

Large-Scale Simulation of Regional Demand Flexibility Implementation and Customer Economic Impact

*Hayden Reeve, Steve Widergren, Robert Pratt, Trevor Hardy, Sadie Bender, Sarmad Hanif, Mitch Pelton, Fernando Bereta dos Reis, Ankit Singhal, and Ahmad Tbaileh, Pacific Northwest National Lab
Bishnu Bhattarai, Department of Energy*

ABSTRACT

The Distribution System Operator with Transactive (DSO+T) study conducted a large-scale simulation of over 60,000 customers in a region the size of Texas to demonstrate the effective coordination of distributed energy resources (DERs) in commercial and residential buildings. The integrated simulation included both the bulk (wholesale generation and transmission) and distribution systems. The DERs (including batteries, electric vehicles, air conditioning, and water heaters) participated in a transactive energy retail market that was integrated into an existing competitive wholesale market. The engineering and economic performance of the resulting demand flexibility was evaluated over annual simulations for both moderate and high renewable generation scenarios. A detailed parametric cost model was developed to enable detailed economic analysis of key stakeholders. In addition, fixed and dynamic customer tariffs were designed and applied to the customer population. This allowed the impact on annual customer bills to be analyzed for various building types (residential versus commercial; single- versus multi-family). This paper presents results showing the relative flexibility of batteries, electric vehicles, and building loads throughout the year and under different renewable scenarios. This feeds a detailed breakdown of the impact this flexibility has on the operating costs of the grid and the resulting net economic benefit. Finally, the study showed that practically all customer classes (including non-participating customers) save money under the proposed demand flexibility scheme. The study found overall net annual economic savings of \$3.3-5.0B for a region the size of Texas equating to average customer bill savings of 10-16%.

Introduction

The operation of the electric grid is becoming increasingly more complex and challenging due to load growth associated with electrification of heating and transportation, deployment of intermittent renewable generation sources (such as wind and solar), and the occurrence of extreme weather events that increase energy demand and reduce the reliability of supply beyond prior experience. Distributed energy resources (DERs) can offer considerable flexibility to grid operation but also presents a key challenge: effectively and economically coordinating large numbers of DERs to provide grid services is non-trivial 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. 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 DERs invest in and operate their assets in ways that support safe and reliable operation of the electric grid.

This paper evaluates the use of transactive energy to coordinate DERs through transparent, value-based means. Transactive energy uses scheduled transactions involving value signals (e.g., prices) and energy quantities to give the feedback necessary to “close the loop” and achieve effective, stable, and scalable coordination of flexible assets. Several field demonstrations of transactive energy have shown its feasibility and benefits at the building, campus, and community scale (Hammerstrom et al. 2007; AEP 2014; Battelle Memorial Institute 2015; Cazalet et al. 2020). However, questions remain about the impact of DER flexibility and transactive energy’s engineering and economic performance when deployed at scale.

This paper summarizes the only large-scale analysis of a transactive framework with fully coupled transmission, distribution and building systems. This ensures the intricate complexities of device dynamics, delivery constraints, market conditions, and economic impacts are captured in an integrated approach. Moreover, this allows for detailed mapping of individual customer and DER behavior and their economic outcomes to region-level load and market impacts and the resulting benefits. In addition, we demonstrate that, at a regional scale, it is possible to operate a fully responsive DSO in real time, with non-trivial penetration levels of DERs participating in the retail market.

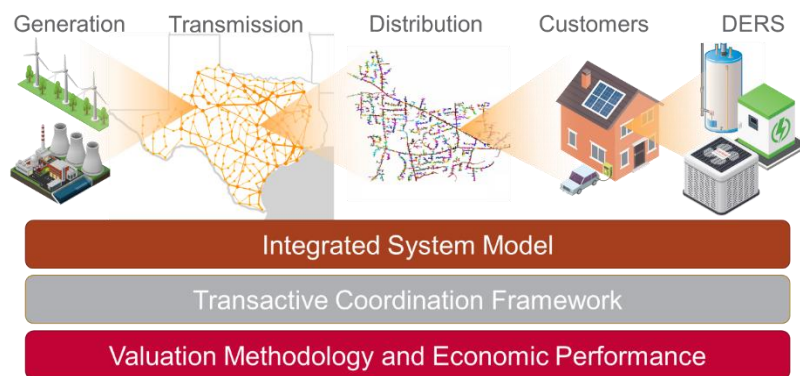


Figure 1. Overview of the DSO+T study breath and key elements.

Study Overview and Objectives

To address these questions the Distribution System Operation with Transactive (DSO+T) study evaluated how a DSO can engage the large-scale deployment of flexible DERs, (such as heating, ventilation, and air conditioning [HVAC] units, water heaters, and batteries) by using transactive energy mechanisms (Reeve et al 2022a). All transactive cases run for moderate and high renewable generation scenarios and were compared to a business-as-usual (BAU) baseline. This assessment was conducted using a highly interdisciplinary co-simulation and valuation framework that encompassed the entire electrical delivery system from bulk generation and transmission, through the distribution system, to the modeling of individual customer buildings and DERs. The assessment framework has three key elements (Figure 1): the design of a transactive coordination and market integration framework; an integrated simulation model; and an economic valuation methodology.

Ultimately the goal of the study was to determine whether the implementation of a DSO and transactive energy retail market: 1) Ensures effective and stable coordination of DERs; 2) Is

cost effective for both participating and nonparticipating customers; and 3) is equally applicable and beneficial to future renewable generation and DER deployment scenarios (for example smart building loads versus energy storage).

Prior and Related Research

The overall simulation is built on prior work including the modeling of DERs in the context of the distribution system to assess the performance and benefits of demand response for various end loads (Fuller et al. 2012). More recent work bridged the transmission/distribution system divide by demonstrating the integrated simulation of DERs responding to and affecting wholesale prices (Mukherjee et al. 2020). Other work has used publicly available data to develop annual hourly load profiles for regions using either physics-based models (Hale et al. 2018) or load profile data (Lee et al. 2021). These studies did not include demand flexibility, while others incorporate estimated levels of performance, for example assuming demand flexibility can be acquired at \$60/MWh (Vibrant Clean Energy 2019) or using projected program participation rates (Lee et al. 2021). This study seeks to demonstrate successful price-responsive DER coordination, thereby requiring the co-simulation of the coupled bulk and distribution system at fine (15-second) time resolution to generate 5-minute load profiles. In addition, physics-based models are required for individual buildings and DERs to assess the magnitude of available flexibility throughout the year and to understand the impact of demand flexibility on customer amenities such as electric vehicle (EV) battery state of charge or indoor comfort.

In terms of estimating overall benefits of demand flexibility, the National Roadmap for Grid-Interactive Efficient Buildings focuses specifically on the gross benefits of response from flexible building loads, in addition to energy efficiency, given an achievable level of deployment through 2030 (DOE 2021). The benefits are based on model projections of power system hourly loads and marginal costs for energy, avoided generation and transmission capacity, and ancillary services through 2050 in 134 U.S. balancing areas. Demand flexibility is dispatched by a price-elasticity model providing optimal timing of load shifting for up to four consecutive hours per day. Other sources of flexibility associated with buildings were not analyzed, such as rooftop solar, batteries, and EV charging. This and other studies (Hale et al. 2021; Hledik 2019) report on overall aggregate benefits but do not assess the expected economic impact on individual customer's net of estimated implementation costs. This study aims to provide both macro- and micro-economic perspectives so aggregate customer savings can be assessed as well as expected impact on individual customers and DSOs as a function of key attributes.

The economic assessment and cost models in this study are informed by prior work on estimating distribution substation (Dagle and Brown 1997) and transmission system costs (WECC 2012). In addition, various means of assessing the avoided costs for transmission and distribution systems as a function of reduced loads are analyzed in (Synapse Energy Economics et al. 2018). Assumed asset costs for flexible loads appear in (Dyson et al. 2015) and cost data from various sources are summarized and evaluated in (Potter and Cappers 2017). Current costs for a wide range of storage technologies can be found in (Mongird et al. 2020). Finally, prior work (Zeng et al. 2017) collected and visualized power sector cost data. This work broke down estimated revenues by load serving entity type, regional transmission organization/ISO region, generator ownership model, and finally generation fuel source.

The remainder of this paper describes the transactive coordination scheme, integrated simulation environment, and the economic valuation methodology. The analysis scenarios are then presented prior to results and conclusions.

Transactive Coordination and Market Integration

The transactive coordination and market integration framework was designed to integrate a retail transactive market into existing day-ahead and real-time wholesale energy markets (Widergren et al. 2022). Central to this approach is the use of dynamic rates that strive to better reflect cost causation and incentivize valuable customer responses. This transactive rate structure captures the DSO costs with a dynamic retail price reflecting the cost of wholesale energy purchases, a volumetric charge to recover variable DSO expenses, a congestion charge to manage distribution system constraints, and a fixed connection charge.

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 that are a function of projected wholesale market prices. Customer DERs have transactive agents that determine an optimal operating strategy (and resulting load quantity) over the next 48 hours based on the retail price, weather, and usage forecasts and customer settings (i.e., preference between comfort and cost savings). The DSO then combines the resulting customer price-quantity demand bids for the forecast horizon. These bids are cleared using a double-auction mechanism and updated price and cleared quantity forecasts are provided to participating customers at the next hour interval in the retail market. 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. This market clearing repeats every hourly interval, 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 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.

Integrated Simulation Model

This scheme's impact on the distribution and bulk power system was modeled in a fully integrated co-simulation environment that included a 200-bus transmission model, 40 DSOs, the 63,729 buildings (58,453 residential and 5,273 commercial), 73,704 HVAC units, and 36,624 water heaters, representing a 1:172 scale. The Electric Reliability Council of Texas (ERCOT) region was selected as a representative system to serve as the basis of this model as it has a generation mix with significant amounts of wind, is summer peaking, served by an ISO wholesale market, and is of tractable size with no synchronous interconnections.

The distribution of commercial and residential buildings was based on the DSO type (urban, suburban, or rural). Each building was procedurally generated with its own unique type (e.g., single family, multifamily, retail, warehouse, or office), vintage, size, and form factor. The insulation levels, thermal mass, and window and HVAC performance were based on building vintage, climate zone, and typical building practices and codes at the time. Operating and occupancy schedules and plug loads were randomized from typical values based on building type. Buildings were simulated in GridLAB-D to ensure dynamics, thermal mass and comfort impacts are captured in the simulation (GridLAB-D 2017). The result is a diverse set of buildings with different time-varying loads that were scaled for each DSO to represent all ~12.2M customers on ERCOT. Figure 2 shows an example of the variation of residential building size and resulting annual load and load factor (the ratio of average load to peak load). More details on the building definition procedure are provided in (Reeve et al. 2022b), Sections 6 and 7. For

simplicity, industrial loads were assumed to be constant for the entire year based on the low variation seen in (Hale et al. 2018), and their magnitude at each node was based on ERCOT utility data.

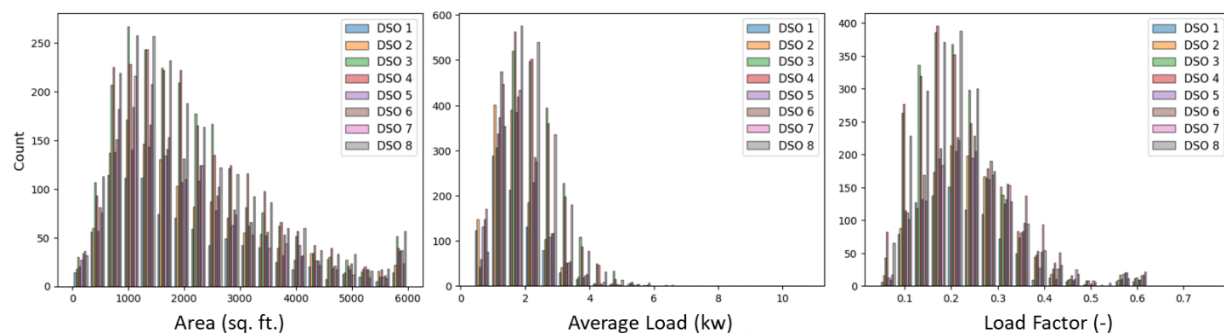


Figure 2. Residential building distributions for size (sq. ft.) and resulting average load (kw-hrs.) and load factor.

For the moderate renewables (MR) scenario this load was met by a generation mix of coal, natural gas, nuclear, and wind. The number, location, and capacity of the bulk system generators are based on the ERCOT test system (Battula et al. 2019) that used U.S. Energy Information Administration data to determine the aggregate amount of generation (by fuel type) at each transmission bus. Literature sources were used to define generator performance parameters such as ramp rate (Gonzalez-Salazar et al. 2018) and startup costs (Kumar et al. 2012) and cost parameters were defined to approximate inferred 2016 ERCOT generator heat rates (Potomac Economics 2017).

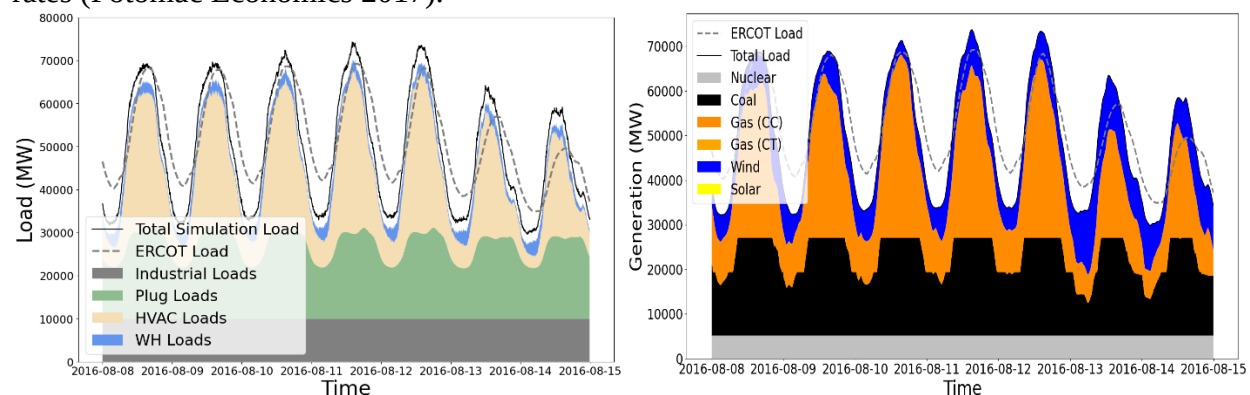


Figure 3. Daily variations in BAU loads (left) and generation dispatch (right) compared to total ERCOT load.

The output of wind generators was based on a stochastic model (Chen et al. 2010) calibrated to 2016 ERCOT hourly wind generation data. Illustrative load and generation profiles are shown in Figure 3 and are compared to actual 2016 ERCOT system load data. The annual simulation predicts peak and average system loads within ~5% percent of reported ERCOT values; however, the minimum total load was overpredicted by ~10%. In addition, the daily variation in load was overpredicted (on average by ~37%). The overprediction of daily load variation has been reported by other researchers who also used physics-based load profile models (Hale et al. 2018). The integrated simulation model ultimately enables the accounting of electricity generation and consumption by generator type, customer class, and end use as shown in Figure 4.

The study a 200-bus transmission models based on the ERCOT test system (Battula et al. 2019) that synthesized generic transmission network designs using population and load data. Figure 5 shows resulting transmission line utilization levels and resulting real-time market prices during the system peak load.

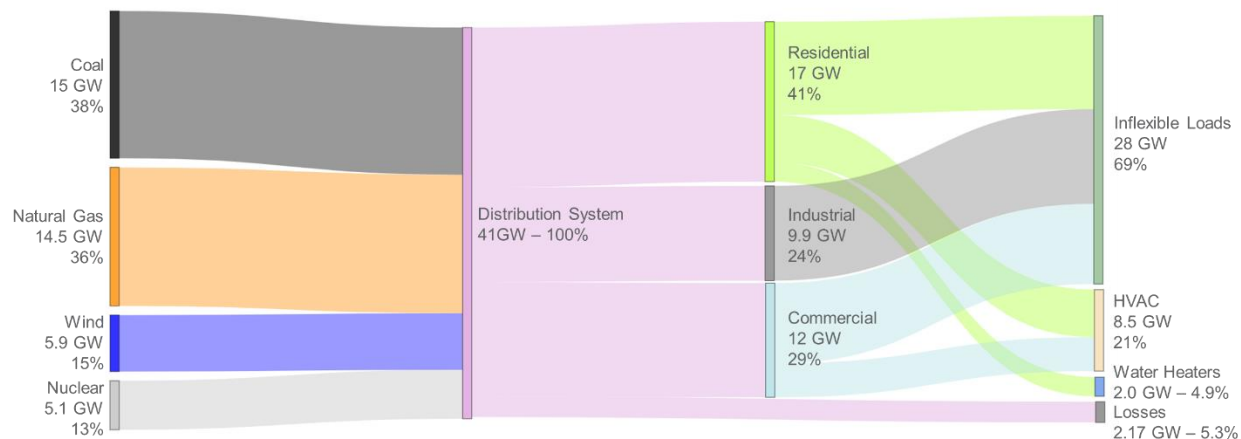


Figure 4. Summary of resulting annual average energy contributions by generator, customer, and end-load types.

Transmission line capacity constraints combined with generator operating cost and performance constraints fed the solution of a security-constrained economic dispatch and unit commitment optimization in AMES (Battula et al. 2019) to calculate day-ahead and real-time wholesale market locational marginal prices (LMPs) for the entire region. This ensured market prices factored in demand changes as a function of daily, seasonal, and geographic variations. The simulated real-time market prices matched actual ERCOT price trends (Figure 5) and the annual simulated day-ahead prices were found to be representative (within $\pm 20\%$) of average prices seen in electricity markets across the country (for example ERCOT, CAISO, and PJM). However, the simulation does not capture less frequent but large price excursions and underpredicts median daily variation in day-head prices by 32-70% when compared to these three regional markets. As such the presented study results likely underpredict the savings that demand flexibility realizes in the energy market.

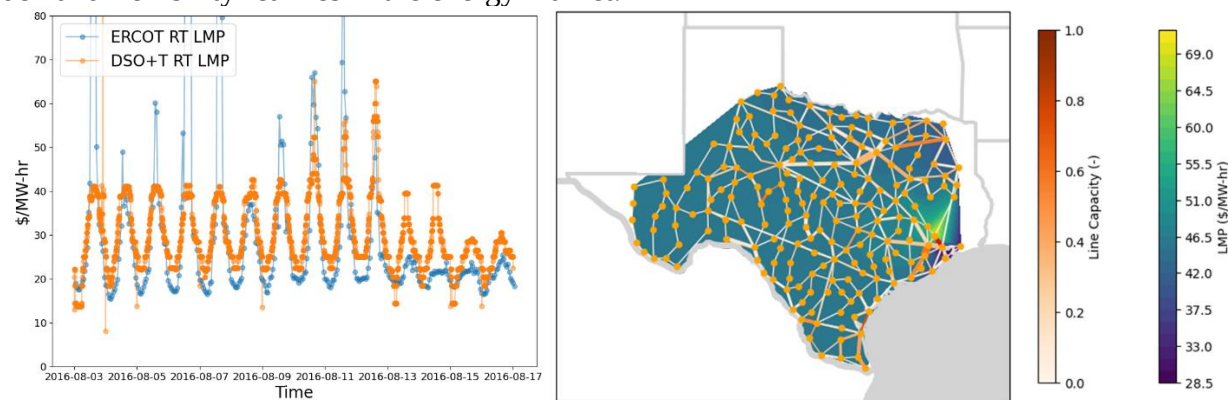


Figure 5. Temporal (top) and geographic (bottom) variations in simulated real-time LMPs.

Economic Valuation Methodology

To assess the economic impact of the transactive scheme on the financial performance of stakeholders, an economic valuation methodology was used based on a rigorous value activity model (Pratt et al. 2022). This analysis determined the annualized cash flow of grid operation participants (customers, DSOs, transmission system operator, generators, and ISO) at a level of granularity sufficient to understand the financial benefits and costs incurred by each party. The result is a rigorous parametric modeling framework that can track value (e.g., cash) flows throughout the entire electrical delivery system (Figure 6). The level of granularity allows analysts to understand the sources of value arising from implementing DER flexibility solutions as well as sources of increased expenditure for implementing the transactive framework.

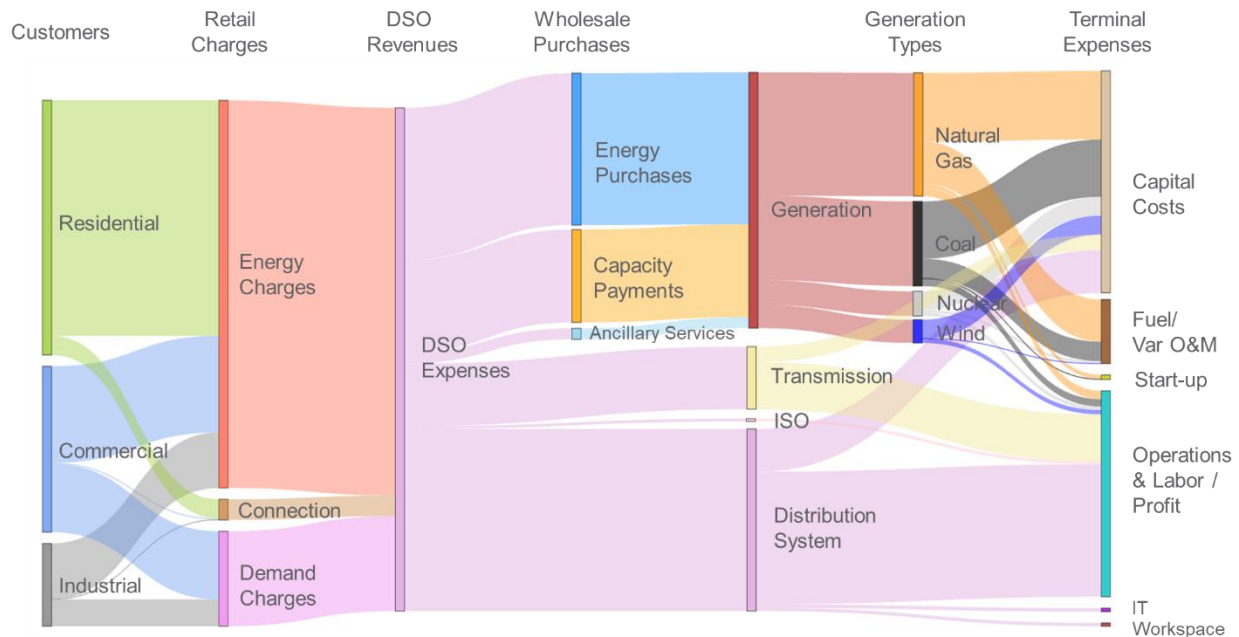


Figure 6. Integrated cash flow analysis of DSO revenues and expenses.

DSO revenues were collected by applying retail rate structures to customers modeled in the large-scale simulation described above. This necessitated development of a transactive retail rate design that incorporated dynamic day-ahead and real-time retail pricing. In addition, nonparticipating customers (and all customers in the BAU case) were subject to a flat-rate tariff.

To determine DSO costs, simulation results were also used to calculate wholesale energy purchases as well as capacity, ancillary services, transmission access, and ISO payments. While this study modeled the ERCOT region, a more generic wholesale market was assumed, including a capacity market. This study assumed a nominal capacity market price of \$75/kW-year based on an examination of reported U.S. capacity market prices over time (Jenkin et al. 2016; Bowring 2013). The study also applied a quantity-price sensitivity factor of 5 based on reported sensitivities to capture the nontrivial impact that reducing the required capacity has on the cleared capacity market price. These assumptions are identical to the values used in (DOE 2021) for their 'High Capacity Value' case. The annual transmission access fees paid by DSOs were assumed to be \$12.30/MWh, based on the California ISO's 2020 postage-stamp rate for transmission access. A portion of this covers transmission infrastructure costs that analysis determined to be \$169/kW. Based on the calculated annual cost of capital of 8.25%, this resulted

in an annual cost of transmission infrastructure of \$13.9/kW-year. This agreed well with the avoided cost of transmission (\$15/kW-year) used in (DOE 2021). ISO fees of \$0.555/MWh were assumed based on published ERCOT rates.

Parametric models were developed to estimate the annualized costs of DSO capital investments, including substations, feeders, meters, and information technology systems. The impact of both greenfield and brownfield growth rates on capital costs was included through development of a dedicated growth rate model. Operating costs were also estimated for labor, workspace, and operations and maintenance materials. Finally, the effect of DSO attributes (rural, suburban, and urban) as well as ownership model (investor-owned, municipal, or cooperative) factored into the parametric analysis including the annualized cost of capital. Cash flow models and analysis methodologies were also developed for customers, generators, ISO, and transmission operator (Pratt et al. 2022).

The resulting system-wide effective cost of energy sold calculated by the study (\$0.11/kWh) was within 7% of the 2016 national average. This confirmed the developed model is representative of typical electrical system operating expenses. It illustrates the ability of these models to estimate savings (for example, in wholesale energy purchases, capacity payments, transmission access fees, distribution capital costs) and increased expenditures (for example, in communication network expenses and retail operations) associated with the deployment of a DER flexibility coordination scheme such as transactive energy.

Analysis Scenarios

The engineering and economic performance of the transactive energy framework was studied for two DER deployments: high penetrations of flexible loads (residential and commercial HVAC units and residential water heaters) and behind-the-meter batteries. For the flexible load case it is assumed that 80% of customers participate to represent a future state with high levels of flexibility. For the battery case, the scenario assumed that 40% of buildings have a battery with an average capacity of ~14 kWh each (a total capacity of 23 GW). The results of each transactive case were compared to a BAU case. These cases were subject to two renewable generation scenarios. The MR scenario was based on the generation definition in (Battula et al. 2019) that achieved 14% annual renewable generation. The future HR scenario doubled the contribution of wind and added 14.8 GW and 21.3 GW of utility and rooftop solar respectively. This resulted in 40% of annual generation coming from renewable sources with >75% renewable generation ~10% of the year. The HR scenario also assumed that 33% of residential buildings had an EV (with 80% participating).

Results

System-Level Impacts

The transactive coordination of flexible assets disincentivizes consumption during periods of high prices (typically associated with high electrical demand during the afternoon and evening) and incentivizes relatively higher electrical consumption (for example, precooling, preheating, and EV charging) during periods of low prices (typically during nighttime). These trends can be seen in the load profiles of Figure 7 showing the impact of flexible load operation on the system peak load experienced in August. The net result of HVAC and water heater flexibility in the MR scenario decreases peak loads by ~8.8% (6.5 GW) while increasing the

minimum system loads and decreases the daily variation in load by ~17% for the peak day. A summary of the annual variation in system loads are shown in Figure 8.

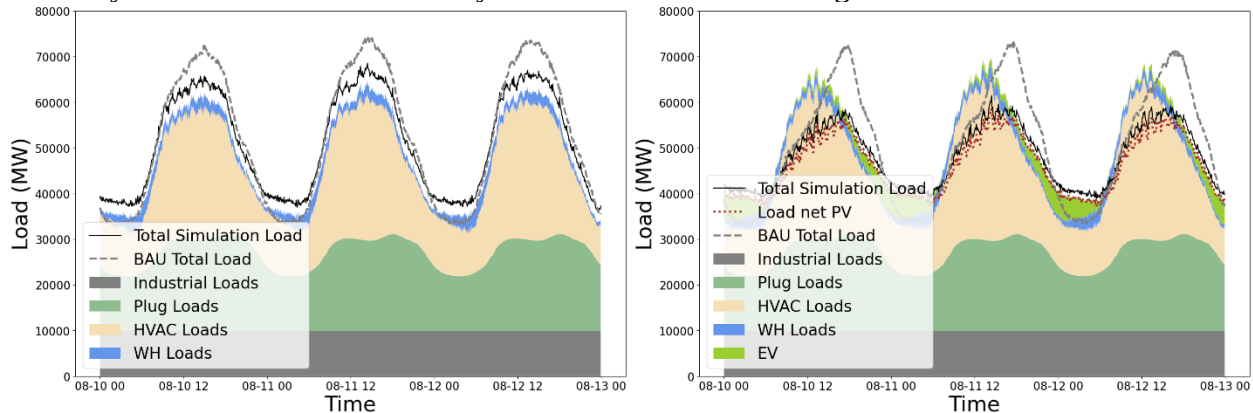


Figure 7. Peak load profiles for the flexible load case under the MR (left) and HR (right) scenarios. The BAU case load profile is shown with a dashed grey line for comparison.

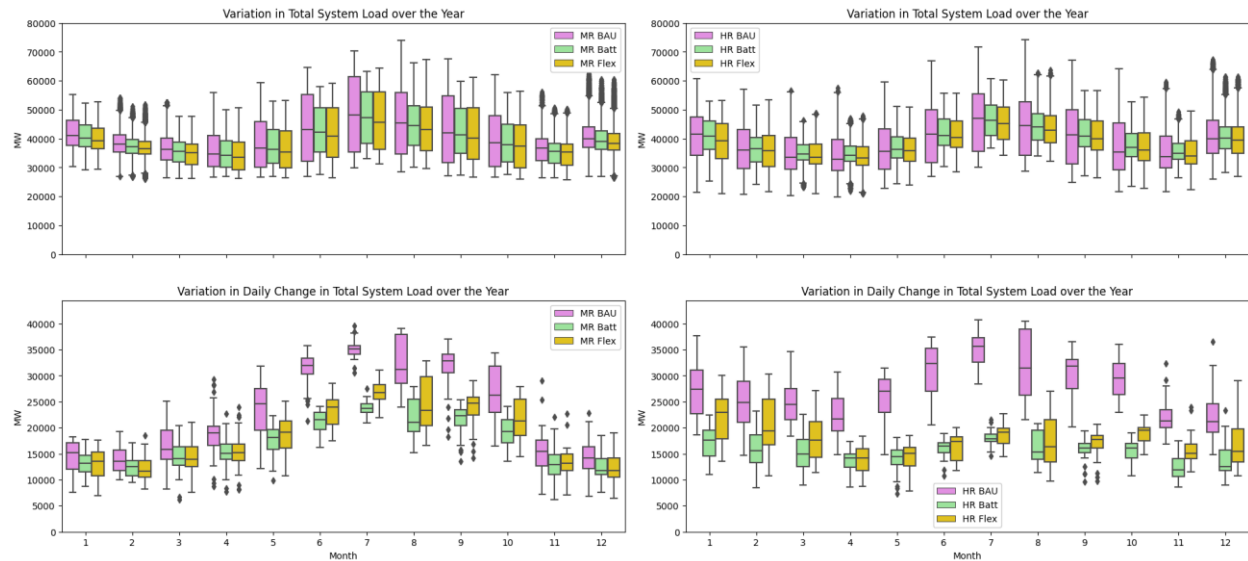


Figure 8. Annual variation of system load (top) and daily load change (bottom) for the MR (left) and HR scenarios (right).

In the HR scenario, the peak load reduction is substantially higher (>14%) for the flexible load case. This is due to the inclusion of smart EV charging (V1G) that also contributes to load reduction as shown in Figure 7 (right). The BAU case experienced a peak EV charging rate of ~6 GW (representing 9% of peak load) in the afternoon of the peak day (August 11). This is reduced to practically zero in the transactive case. The system loads are then further flattened by shifting HVAC load. The total reduction is the difference between the dashed grey line (BAU total load) and the solid black line (flexible case total load). In both scenarios the battery case provided similar levels of peak load reduction.

The HR scenario also added a large amount of rooftop and utility solar. This resulted in the large daily variations in system net load (that normally only occurred in the summer for the MR scenario) persisting throughout the year (Figure 7 lower right). These results also highlight that while flexible loads (EVs, HVAC, WH) are effective resources when their loads align with

periods of system constraints (such as peak load) they are, however, less effective during periods of time when they are unavailable or have less need and capacity of pre- charging, heating, or cooling. Figure 7 shows this trend, highlighting the ability of flexible loads to reduce system peak loads and daily variation during the summer months, but their diminished capability to reduce the HR scenario’s daily variation in system loads during shoulder and winter seasons. This is primarily due to a diminished ability of heating loads (compared to batteries) to shift demand from overnight and morning hours to midday to fill the solar ‘duck’ curve during winter and shoulder seasons.

Annualized Economic Impacts

The simulation results (in particular, system loads and energy market prices) are key inputs into the economic analysis that determines changes in annualized cash flow by stakeholder. Figure 9 summarizes the changes in annualized cash flow between the BAU and flexible load case for the MR scenario. This will be used to illustrate the drivers behind system benefits and implementation costs. Net benefits are then presented for the other cases along with a sensitivity analysis.

The primary benefit of a DSO+T implementation comes from reduction in system peak load and the resulting required generation capacity. Peak load reduction lessens the quantity of generation capacity that must be procured in a capacity market and also substantially lessens the resulting price for this capacity. It is this second attribute that results in large savings. The reduction in peak load also saves transmission and distribution costs resulting from the deferral of growth-driven capital investments in this infrastructure. These benefits have been calculated for general growth rates and transmission and distribution system designs. Actual benefits will be highly dependent on the actual load growth rates and system constraints seen on an operator’s system.

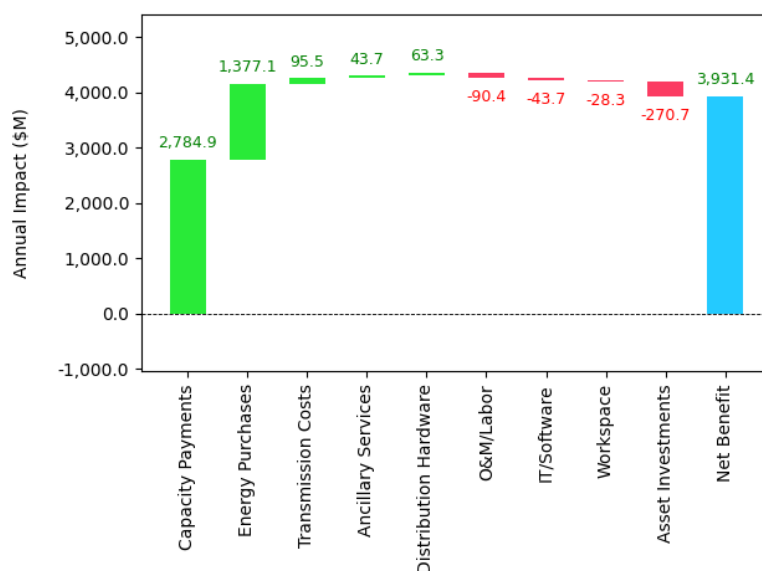


Figure 9. Summary of changes in annualized cash flow between the BAU and flexible load cases showing economic benefits and costs of implementation (MR scenario).

There are also wholesale market benefits from savings in the purchases of energy. These savings are due to the reduction in peak loads (and therefore not having to dispatch expensive

generation) that results in lower average prices. More importantly, however, is the fact that flexible assets shift more of their consumption to periods of lower prices. So, for the MR flexible load case average day-ahead prices dropped 7% and the cost of energy purchases dropped ~14%.

The costs to implement a transactive retail market as well as flexible assets are borne by the DSOs and customers. DSO labor is assumed to increase due to the personnel needed to run the retail marketplace, additional automated metering infrastructure operations capability (+25%), strengthened retail operations (+20%), and cybersecurity (+5%). This increase in employee headcount results in a small increase in workspace costs. Information technology costs are also estimated to increase due to the implementation of a retail marketplace and the required DER communications network. Finally, we assume that the cost to implement or upgrade DERs is borne by the customer and captured in their annualized cash flow. This analysis assumed total installed marginal first costs associated with enabling flexible assets of \$164 for residential thermostats, \$318 for residential water heaters, and \$254 for EV chargers (Pratt et al. 2022). These costs represent the marginal increase in cost over existing baseline systems that lack the required connectivity. Batteries assume a first cost of \$83/kWh. This aggressive estimate assumes that battery prices will continue to fall and other value propositions (resiliency, self-consumption of on-site generation, deferred customer electrical system upgrades, etc.) will account for any remainder of the cost.

The net result of these wholesale and capital infrastructure benefits combined with DSO and customer implementation costs is an annualized benefit of \$3.9B. This value includes all transmission system operator, ISO, and DSO costs and required revenue recovery and is the net benefit that is seen by customers after annualized DER costs have been included. The HR case results in higher overall benefits (\$5.3B) due to the additional load reductions contributed by smart EV charging.

Sensitivity of Annualized Economic Benefits

Since the majority of the system savings are derived from reductions in capacity market payments, the net benefit was also calculated under both high- and low-capacity price assumptions (Figure 10).

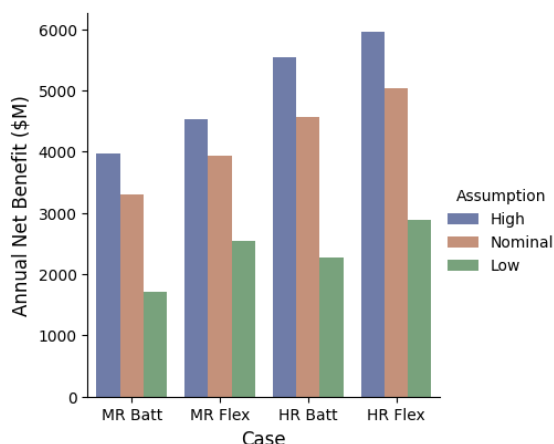


Figure 10. Summary of annualized net benefit to customers for each case under low, nominal, and high-end capacity price assumptions.

Future capacity market prices will likely be driven by the addition of renewable generation (which may suppress capacity market prices), load growth due to electrification of space heating and transportation, and growing needs for resource adequacy for extreme events. Both the load growth and resiliency needs will trend to increase the demand for new generation and potentially increase capacity market prices. For the ‘low’ assumptions we assumed a halving of the capacity cost (\$37.5/kW-yr). This is at the lower end of almost all the regions for which 2030 average generation capacity cost was calculated in (DOE 2021). For the ‘high’ assumptions we use a capacity value of \$91/kW-yr to reflect the full annualized cost of a peaker plant. Even under low-capacity market assumptions, the net benefit was \$1.7-1.9B.

Customer-Level Impacts

The simulation results support the investigation of benefits by individual DSO and customer. The distribution of percentage savings in annual electric bills for customer segments simulated on the largest DSO are shown in Figure 11. Figure 11 (left) shows that participating customers save more than nonparticipating customers, but that practically all customers save on their average utility bill. Across the entire study participating customers save an average of 14-20% on annual electric bills. Nonparticipating customers are assumed to be on a flat declining tiered rate structure designed to collect revenue equivalent to that if they were enrolled in the dynamic transactive rate tariff. As a result, nonparticipating customers save 9-11% on average and practically all customers see a reduction in their annual electric bill.

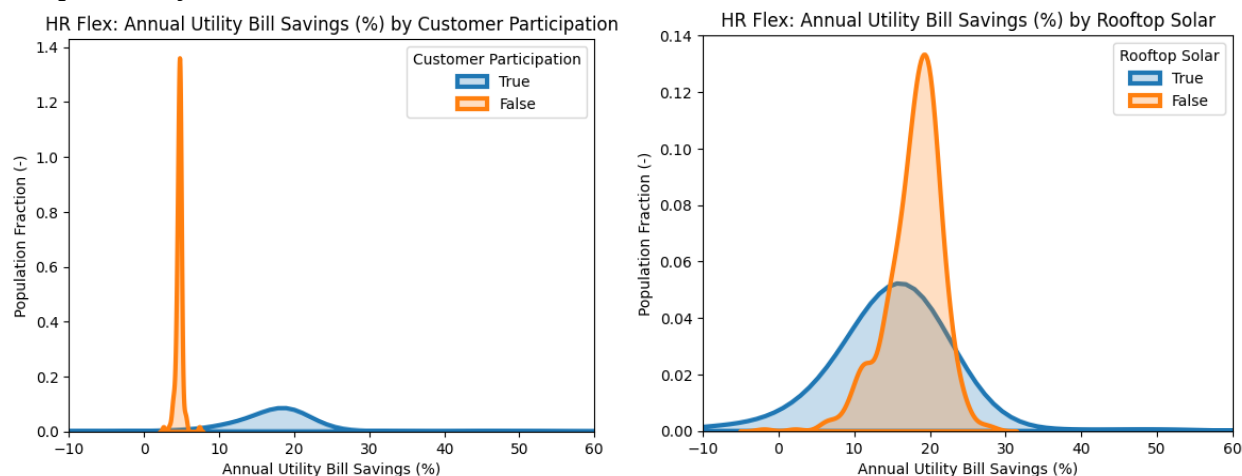


Figure 11. Distribution of annual savings in electricity bills for participating and nonparticipating customers (left) and for participating residential customers with and without rooftop solar (right). (HR flexible load case; DSO #1).

The inclusion of thousands of individual customers and DERs in the simulation allows for the investigation of savings by DER ownership. The impact of HVAC, WH, EV, and battery participation on overall electric bill and investment costs was evaluated in the study. For illustration Figure 11 (right) shows the performance of participating residential customers with and without solar rooftop. In this case even solar customers subject to dynamic rates save money compared to a flat rate. This is because the reduced overall cost basis of the DSO benefits all customers (including non-participating and solar customers) with participating customers seeing greater savings.

Discussion

As the electric grid decarbonizes more of its operating cost will be associated with the recovery of capital infrastructure costs. This study shows (Figure 6) that even today wholesale energy purchases represent less than a third of the grid's operating cost, with variable costs (fuel and variable generation O&M) accounting for less than 15%. Conversely, capital costs represent almost half (44%) of the grid's annualized cost while approximately 40% of the grid's cost structure is associated with labor, maintenance, and operations costs. Flexibility incentives and dynamic rate designs need to effectively address both energy market costs and infrastructure costs. The designed rate and congestion charge do effectively reduce capacity and investment costs but more research is needed (and underway) into dedicated methods for dynamic capital cost recovery. Flexibility incentives also must not unfairly disadvantage any particular customer segment. An important feature of this study's rate design is the fact that nonparticipating customers share in the overall benefits. The customer rate structure assumes that nonparticipating customers remain on a fixed tariff and that this tariff is designed to recover revenue equivalent to the amount that would be collected if nonparticipating customers were on the dynamic transactive rate. This ensures that nonparticipating customers are charged under the reduced cost basis that the DSO experiences due to overall demand flexibility, thereby sharing in the savings. This ensures that customers who may not be able to install flexible assets (e.g., disadvantaged communities, renters, etc.) are not burdened by increased costs.

This study has demonstrated that a transactive retail market is effective for a range of flexible assets, both traditional flexible loads (such as water heaters and HVAC units) as well as stationary batteries and the managed charging of EV batteries. The annual simulation of both cases across the moderate and high renewable scenarios provides insights into the relative suitability and potential of various flexible assets to manage load. Flexible loads provided effective flexibility when grid constraints and price incentives aligned with their operation. This is the case during the system's peak load that occurs during the summer afternoon, which aligns with peak HVAC operation and EV charging. EVs represent both a significant new load and a substantial new source of flexibility. Our modeling showed that if unmanaged EV charging aligned with the system peak load, increasing it 9%. Practically all this load could be shifted from the afternoon and evening peak to overnight hours. Flexible loads were found to be less effective when grid needs did not align with the assets' availability or operation. For example, HVAC heating and EV charging only provided minor increases in minimum winter load caused by the solar 'duck' curve. Batteries provided much greater flexibility and resulting reductions to daily system load variation during these times. This suggests the need for a mix of flexible assets: flexible loads that can alleviate their contributions to system peak loads and local delivery constraints; and batteries and other storage mechanisms that can address excess renewable generation that does not align with nominal loads, either due to mild temperatures not requiring space conditioning or EVs being in-use and away from charging stations. Ultimately this study does not recommend any specific mix of flexible assets or prescribe a renewable future scenario.

Conclusions

The DSO+T study has successfully simulated a representative integrated electricity delivery system and associated economic cost model. This capability allowed the evaluation of the engineering and economic performance of a transactive energy coordination scheme. A distribution-level transactive energy marketplace was designed to integrate into existing

competitive wholesale markets including day-ahead and real-time market operation. Annual simulation results show that the transactive energy scheme provides effective and stable operation of a large penetration of DERs. Peak loads are reduced 9-15% and daily variation in load is reduced 20-44%. In addition, a rigorous economic assessment demonstrates that such an implementation would result in nominal savings to DSOs and customers of between \$3.3-5.0B per year depending on future DER and renewable generation scenarios.

The majority of the economic benefit stems from the reduction in required capacity and associated reduction in capacity price. While sensitivity analysis demonstrates a positive value proposition even assuming low-capacity price assumptions, with its large contribution to benefits and uncertainty about future load growth and generation capacity needs this area warrants further investigation. In addition, while wholesale energy purchases only contribute to approximately 25% of the cost to operate the grid, infrequent scarcity-driven events can cause large variations in wholesale price. Furthermore, the accelerated deployment of renewable generation will increase the period of time wholesale markets experience negative prices. Better understanding the value of demand flexibility during these market extremes will be needed given the increased likelihood of periods of generation scarcity and excess.

This study has also demonstrated that practically all DSO and customer types experience net benefits under a system with large amounts of demand flexibility. Investigating alternative dynamic rate designs and including customer socio-economic attributes will strengthen future investigations in this space.

This integrated co-simulation platform enables the detailed analysis and understanding of integrated bulk and distribution operation and coordination. Such insight will be required to also understand the operation of the grid (and resulting economic impact) in other possible future scenarios including much higher levels of renewables, alternative DER adoption mixes, and analysis of other regions and associated climates.

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