



# Battery Energy Storage Systems for Transmission & Distribution Upgrade Deferral: Opportunities, Challenges and Feasibility in the US Electricity Sector

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## ABSTRACT

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Battery Energy Storage Systems (BESS) are emerging technologies which are opening new opportunities that improve and reduce the costs of electricity. However, exactly where the storage is deployed (generation, transmission or customer) on the electricity system can have an immense impact on the value created by BESS technologies. In this study, we highlight the value created by BESS when installed downstream from a nearly overloaded node at the distribution level by deferring investment in capital-intensive feeder upgrades. The study also examines regulatory policy initiatives in “storage as a transmission asset” and provides recommendations based on the understanding of the regulatory treatment of energy storage to ensure increased deployment of these systems as transmission assets.

**Keywords:** Transmission & distribution, Battery energy storage systems, distribution feeder, load-carrying capability, storage as a transmission asset, load curve, benefit-cost analysis, upgrade deferral.

## 1.0 BACKGROUND

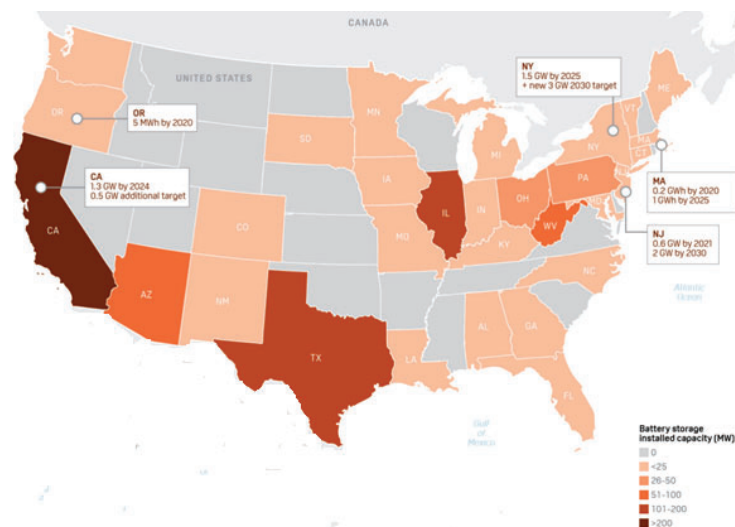
Energy storage has often been called the ‘holy grail’ for a clean energy future because it has the potential to play a pivotal role in the electricity system, especially as the grid ages and new infrastructure is required to maintain reliability. As the falling component and installed costs are leading to favorable economics, policies and market regulations have lagged due to lack of knowledge on the sweeping value streams of energy storage in the current electric grid. The role that energy storage can play in the ever-increasing share of renewables in the fuel mix for the electricity sector is also important to understand.

The electric sector is seeing numerous changes, including the growing adoption of electric transportation and the ever-increasing amount of renewable energy penetrating the grid. These changes will provide many benefits, such as the ability to respond to green public policy goals, increased “diversity of generation options, and increased consumer choice, but these changes will also present several distinct challenges that energy storage can help to alleviate such as (1) increasing consumer demand for reliable, affordable, renewable power options; (2) speed of investment and deployment of variable generation; (3) ancillary services needs resulting from the fact that distributed energy resources (such as storage) create bidirectional power flow that taxes distribution systems which

are reliant upon voltage regulation and protection schemes; (4) “limited transmission capacity which can force resources to be curtailed during their time of peak production, while the expansion of new transmission capacity poses regulatory and environmental challenges.”

The ability of energy storage systems to inherently act like a “sponge,” i.e., absorb energy during excess and discharge energy to the grid when the demand is high, is of paramount importance in today’s grid. Although conventional energy storage systems like pumped hydro (potential energy to electrical energy), have been around for a few generations, battery-based energy storage systems (BESS) are gaining popularity due to their increased efficiency, modularity as well as higher charge density, all characteristics which are suited towards the modern grid. A variety of market reports have emerged hailing grid-scale BESS as the “the next big asset” in the present energy system with annual growth projections of over 10% with a market valuation of \$21.6B in 2018, a number which will grow much higher in the coming years (Adroit, 2019). The U.S. has the world’s largest battery storage market, with 61.8 megawatts of power capacity installed in the second quarter of 2018 with a market growth rate of 60% year to year (Utility Dive, 2019). The U.S. is one of the largest markets in the adoption of battery storage technology at a commercial scale. Currently, 36 states in the U.S. have a combined operational capacity of 1.6 GW of battery storage resources.

**Figure 1: Operational Battery Storage Projects and State Energy Storage Mandates in the US, March 2019**



***Source: DOE Global Storage Database, S&P Global Platts Analytics (March 2019)***

The Federal Energy Regulatory Commission (FERC) defines energy storage as a “resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid (FERC, 2019). This definition is intended to cover electric storage resources capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid, regardless of their storage medium (e.g., batteries, flywheels, compressed air, and pumped hydro). In 2018, FERC finalized two landmark regulations paving the way for the deployment of storage resources in the future. FERC Order 845 proposed reforms to the generator interconnection procedures and agreements to explicitly account for storage resources (like BESS).

FERC Order 841 mandates ISO/RTOs to revise their tariff to facilitate the participation of storage resources in capacity, energy, and ancillary services markets. Transmission entities have filed their comments/compliance plans to these regulations. Recently, ISOs/RTOs such as CAISO (California Independent System Operator) and MISO (Midwestern Independent System Operator) have started deliberations regarding the treatment of “storage as transmission asset” (SATA), which would enable utilities to recover investment costs through transmission rate recovery (TRR). The policy development proceedings are still underway as of June 2019 in CAISO. Based on their location of the application, BESS can be classified into behind-the-meter, which usually entails residential or commercial systems and front-of-the meter which are systems owned and operated by the utilities and independent power producers on the generation, transmission and distribution side of the grid.

In this research, the focus would be on front-of-meter grid-scale (or utility-scale) BESS particularly targeted towards deferring transmission and distribution investments, which can occur due to load growth in a region leading to transmission congestion and rise in electricity prices. The aim would be to evaluate whether grid-scale BESS can allow utilities to defer capital-intensive transmission and distribution upgrades by installing these systems downstream from the transmission/

distribution substation. In this evaluation, it would be essential to cover the characteristics that BESS requires, as well as the opportunities and challenges that it can encounter in this nascent application field. Transmission and distribution upgrades (poles, wires, equipment) have been contentious in the recent past due to high-cost outlay, environmental concerns and high probability of stranded assets which lead to a rise in the actual cost of electricity to the consumers in the service area since the upgrades are added to the rate base leading to an increase in the transmission charge.

## **1.2 Introduction**

With increasing emphasis on reducing global carbon emissions and promoting universal energy access (SE4All, 2017), and long-term concerns over fuel price volatility and energy security (Yergin, 2016), renewable energy technologies, with rapidly declining costs (Kost et al., 2011; Breyer et al., 2013), are becoming an increasingly important part of the future energy system (Jacobson et al., 2009). However, integrating high shares of variable renewable energy sources into power systems can prove to be a challenge (Peters et al., 2011). Out of the several available flexibility measures, energy storage technologies are particularly promising response options because of their unique ability to decouple power generation and load over time. Battery energy storage systems or BESS have emerged as frontrunners to provide a multitude of opportunities for utilities and IPPs to generate revenue through market applications such as energy arbitrage, capacity firming, frequency regulation, etcetera. The development of transmission infrastructure is increasingly facing challenges involving “who pays for” and “who owns” new transmission capacity in part due to the high capital cost, and difficulties in siting transmission infrastructure due to environmental impacts, costs, and aesthetic concerns (Bhatnagar & Loose, 2012). The ability of BESS to provide a secondary source of electrical energy during times of peak overload in a transmission/distribution line or substation has recently been a topic for research, although the commercial viability is still up for debate.

This research tries to understand the techno-economic viability of Battery Energy Storage

Systems (or BESS) by asking three pertinent questions:

1. *What are the general indicators for the viability of BESS as a Transmission & Distribution (T&D) Asset? In other words, why do we need BESS in the T&D sector?*
2. *Can BESS technology be techno-economically viable in deferring capital investments in the T&D sector, i.e., do the economic benefits outweigh the costs when installing & operating BESS as a transmission asset and a transmission + market asset?*
3. *What are the underlying opportunities and challenges for this technology in the T&D system in the future?*

Recent efforts have focused on implementing BESS to serve the load growth in an area where upgrading the transmission & distribution (T&D) infrastructure is difficult due to terrain and other physical conditions. Arizona Public Service (APS) recently purchased a 2 MW/8 MWh Li-ion BESS as an alternative to the traditional approach of upgrading 20 miles of 21-kilovolt cables that service the town of Punkin, AZ (Utility Dive, 2018 (a)). The upgrade required construction through hilly and mountainous terrain, with considerable expense and local disruption, which was avoided with the use of BESS, which would provide the town with peak electricity during the days in which the line was forecasted to be overloaded. Another example, in 2017, a utility that serves customers in Massachusetts announced plans to install a 6 MW energy storage system with an 8-hour duration alongside a new diesel generator on Nantucket Island to provide backup power and postpone the need to construct a costly submarine transmission cable to bring electricity from the mainland to meet anticipated growth in electricity demand (Rusco, 2018).

Another factor that has generated interest is the ability of BESS to avoid stranded assets. System planners must contend with the possibility of stranded T&D assets for infrastructure built in the context of reliability for load growth that never materialized. In South Carolina, ratepayers were saddled with a \$9B bill after two nuclear reactors were abandoned due to cost overruns and lower

than expected electricity demand<sup>1</sup>. Recently energy storage has also been debated in regulatory circles as either a generating asset, transmission asset or both. In November 2018, Generators NRG Energy, NextEra Energy Resources and Vistra Energy filed comments with the Public Utility Commission of Texas (PUCT) last week arguing that transmission and distribution (T&D) utilities cannot legally own battery storage under existing state rules (Utility Dive, 2018 (b)). It has thus become an important issue to define ownership rights around battery storage, which can act both as generation and load on the power grid.

The basic premise for utilizing BESS for the T&D upgrade deferral is fairly straightforward. The utility or the regional planning authority would forecast the peak load periods or days during which the line/substation is overloaded, i.e., exceeds the power handling capacity (in MVA or MW) based on historical load profiles and an annual growth rate. This study is usually conducted in the yearly or 10-year local capacity requirement studies conducted in the transmission planning process. As the demand profile approaches the PHC, congestion in the system increases, as a result of which LMP prices rise. The function of BESS would be to have enough power or energy during these times to serve the load downstream from the transmission/distribution substation. The complexity arrives in the financial valuation of these benefits and costs for the utility and the ratepayers. The literature on BESS application for T&D deferral is scarce and portrays differing values of deferral, making it certain that the value is location dependent. Also, there is a significant gap in literature attributing the benefits of lower-cost transmission upgrades using preferred resources such as BESS for the ratepayers.

Balducci et al. (2018) evaluated the benefits of deferring investment in a substation located on Bainbridge Island, Washington, by nine years, estimating the deferral value at \$162/kW-year. Eyer and Corey (2004) determined the cost of transmission and distribution (T&D) upgrade deferral combined by estimating the cost of the T&D upgrade to be deferred based on \$/kW to be added or the T&D marginal cost (Balducci et al., 2015). The value of

cost deferral can be significant due to the nature of utility cost accounting. For example, if an energy storage system could be used to shave local load peaks resulting in deferral of a \$10 million substation for five years, the benefit would be \$3.2 million if the cost of capital to the utility minus inflation was 8% (Balducci et al., 2018). Another study estimated transmission upgrade deferral benefits at \$36/kW-year based on average annual transmission cost for every unit of reduced peak demand. This estimate is consistent with the average annual transmission cost per kW of summer coincident peak load in ERCOT. On distribution upgrade deferral, it was noted that distribution system costs are driven by non-coincident, local peak loads with deferral value estimated at \$14/kW-year (Schmitt & Sanford, 2018). In this study, the primary metric used has been chosen to ensure a holistic value estimate considering both utility and ratepayer benefits. This would be discussed later in the case study section.

## **2.0 NEED FOR BESS FOR TRANSMISSION & DISTRIBUTION DEFERRAL**

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Battery-based energy storage systems or BESS can become an alternative to building new lines and power plants and help increase the throughput of electricity in existing lines by reducing congestion and unhelpful electric effects, such as voltage issues, thermal overloads, or providing reactive power to the grid. BESS can be positioned downstream from the transmission constraint and charged when the demand for electricity is low (i.e., off-peak or nighttime) and discharge during peak hours. By bringing storage closer to the load, it may also help alleviate high line-congestion and line-loss rates that occur during times of peak demand, this reduces the need for new transmission projects and extends the life of the existing system. It allows grid planners to become more reactive and reduces uncertainty during transmission planning by allowing them to address peaks on a shorter future horizon. But this argument may not hold for locations where the load growth rate is higher than average or where building transmission infrastructure is necessary for reliability and resiliency concerns. Thus, utilities must analyze each situation on a case to case basis

when approaching the idea of implementing BESS before undertaking transmission and distribution (T&D) upgrades. The key factors to consider are briefly examined below:

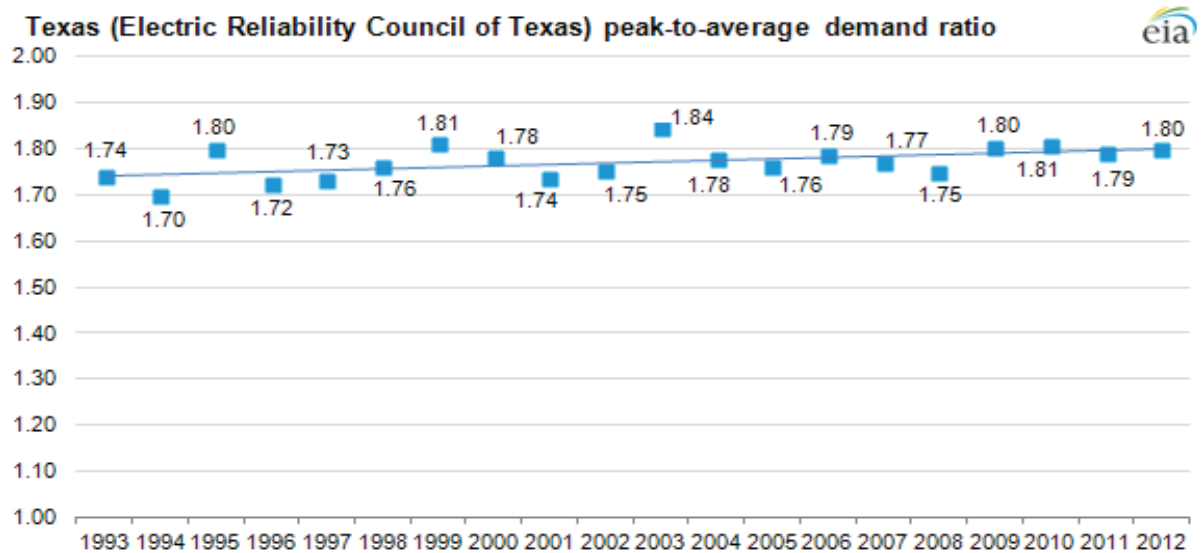
### **2.1 High cost and lead times of T&D investment:**

BESS offers a lower-cost alternative to expensive transmission & distribution upgrades. Infrastructure projects are also prone to cost overruns, environmental concerns, and sometimes public outcry due to right-of-way regulations, this leads to long lead times for approval, construction, and project delivery. All of these constraints could be easily bypassed using energy storage resources, which are much easier to install and operate downstream from a transmission or distribution substation. According to a Department of Energy (DOE) report published in 2015, a typical transmission line could cost upwards of \$1.5M/mile, which is much higher compared to storage alternatives of a similar capacity.

### **2.2 High peak-to-average demand ratio:**

The peak-to-average demand ratio is the ratio of the peak demand to the average demand for a service territory/region. It is a ratio that measures how much higher hourly peak demand is than average hourly demand. A high peak-to-average demand ratio means a large fluctuation in daily electricity demand. A higher ratio also translates into decreasing average utilization levels for generators in a region. Thus, electric systems must maintain sufficient capacity to meet expected peak loads plus a reserve margin. In the US, the peak-to-average demand ratio is increasing (see Figure below) especially in the New England whereas Texas has a flatter curve although it is increasing which is troublesome but offers an opportunity for modular BESS to be operated (discharged) to cover the peak demand periods instead of upgrading the T&D infrastructure just to meet the peak load periods.

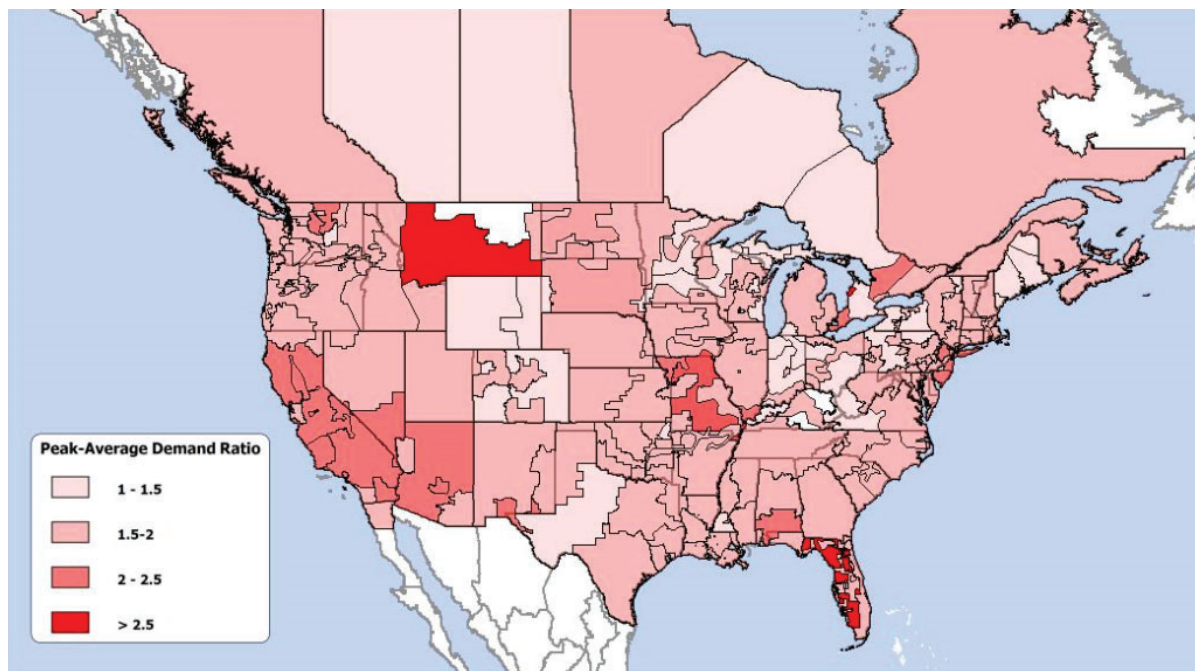
**Figure 2. Electric Reliability Council of Texas peak-to-average demand ratio:**



Source: EIA 2014

From the figure above, it is clear that the peak-average demand ratio has remained around the same level in Texas. However, the higher value of the ratio signifies peak demand exceeds the average demand significantly during peak demand days.

**Figure 3. Peak to average demand ratio for transmission zones across the US**



Source: ICF, ABB Velocity Suite 2019

The figure above shows the high potential viability of BESS in regions such as California, Arizona, Florida, New Jersey, Montana and New England region.

### **2.3 Slow peak demand growth (rate):**

In general, it is more beneficial to defer upgrades using modular resources at hot spots where peak demand is growing slower than it is to defer upgrades of T&D equipment serving the demand that is growing rapidly (specifically, inherent demand growth, not including block load additions such as new commercial facilities and residential development). There are two basic reasons for this. First, if the probability based on historic load analysis portrays that the demand growth will be slow, it usually indicates the need for a relatively small amount of storage resources to defer an upgrade, in a given year. Secondly, since relatively small amounts of storage resources are needed – in a given year – storage resources may be economically viable for more years of deferral if demand growth is low.

### **2.4 Uncertainty about the timing and likelihood of block load additions:**

BESS and other DERs may be attractive alternatives when there is uncertainty about the magnitude and timing of block load additions that would cause an overload. Block load additions are usually related to commercial or residential development or the expansion of existing industrial facilities in a service territory/area. A recent example of uncertain load characteristics in a local service area has been the growth of oil & gas related drilling activities in the ERCOT region (Texas), especially in the Panhandle and West Texas region. The dependence of oil & gas industry electricity usage on the commodity prices of oil also plays a role in shaping the load curve for these regions, which may see spikes during high prices of oil and lower demands when oil prices are low.

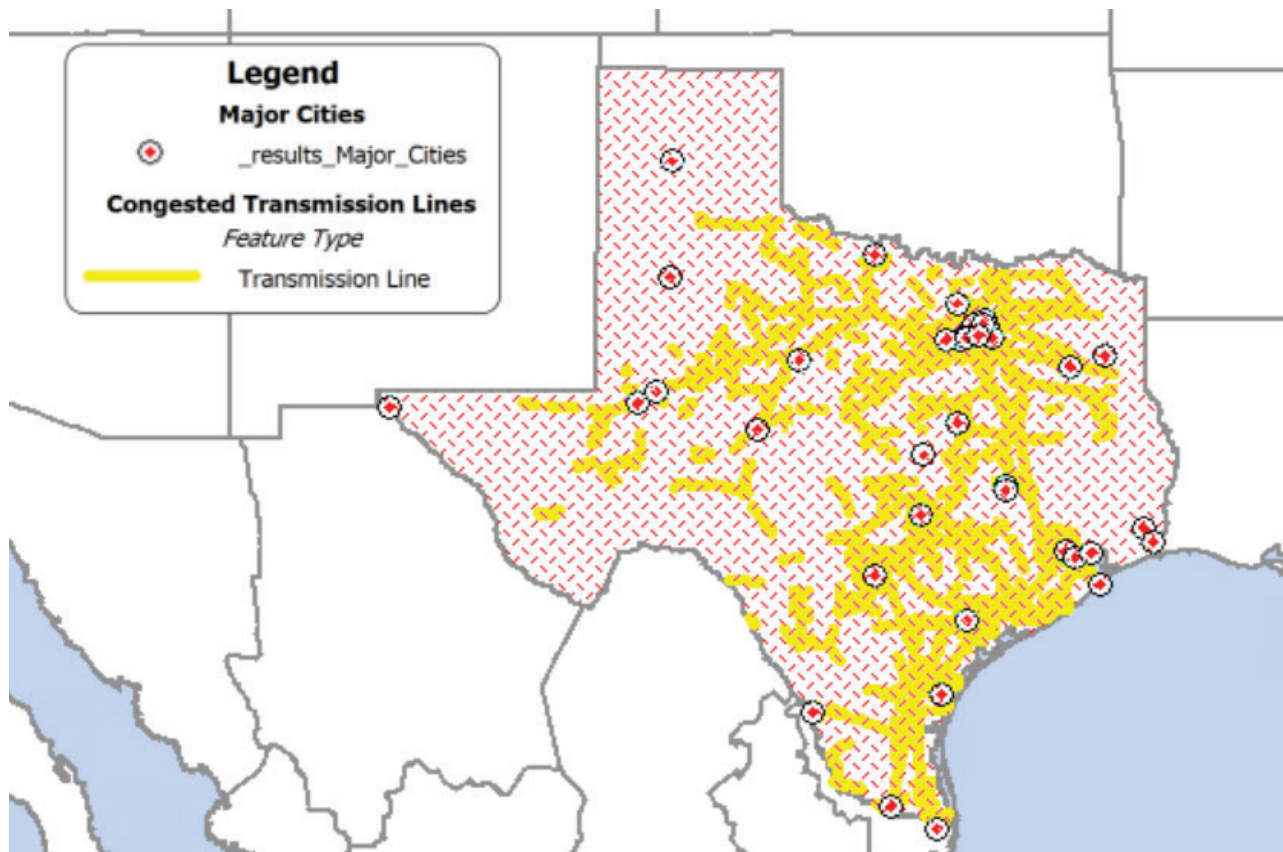
## **3.0 T&D UPGRADE DEFERRAL: A CASE STUDY IN ERCOT SERVICE TERRITORY**

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ERCOT (Electricity Reliability Council of Texas) region has shown a higher demand growth than many other organized markets with a 2.2%/year growth rate compared to US average 1.3%/year from 2000 to 2017 (ICF, 2019). The peak demand in this region is projected to grow at 1.8%/year and total demand at 2.4%/year according to recent market studies. ERCOT is seeing an increase in the amount of energy storage resources being developed for a variety of grid and customer applications in the ERCOT region. As of 2019, 89 MW of utility-scale battery resources, which are a type of energy storage, are registered, and approximately 2,300 MW of new battery capacity was under consideration for the ERCOT region. The recent increase in battery interconnection requests may be due to declining battery technology costs and the availability of Investment Tax Credits for qualifying energy storage systems (ERCOT, 2018).

Many of the battery projects under development are being co-located with solar facilities since batteries can be deployed when solar power is unavailable or at lower output levels to better match load ramps. Batteries also can effectively store wind power that is produced during off-peak hours. A major share of existing battery resources is currently used for Ancillary Services (operating reserves that are procured to respond to variability in load and generation output), which usually means smaller battery systems with short duration discharge capacity (of 30 min – 1 hour). Since FERC Order 841, which encourages greater participation of battery or in general, storage resources in the energy, capacity and ancillary markets does not fall within the purview of T&D deferral, and this value stream has been slow to emerge.

*Figure 4. Congested transmission lines in Texas and their proximity to major cities/load centers.*



Source: Ventyx, ABB.

StorageVET (Storage Value Estimation Tool) is a techno-economic model for the analysis of energy storage technologies and some types of aggregations of storage technologies with other energy resources such as wind or photovoltaic technologies. The tool can be used as a standalone model or integrated with other power system models. The fundamental use of StorageVET is to support the understanding of energy storage project economics and operations. The tool is adaptable to many settings, including policy or regulatory analysis, commercial decisions (by a range of actors), infrastructure planning and research (EPRI, 2018). For evaluation of the financial benefits of deferral to the utility and ratepayers, several cost tests portray the effectiveness of the investment into capital-intensive projects similar to benefit-cost analysis ratios. Each test answers a different question in terms of who and how the investment will assist. A table showing the different tests and their respective purposes and values are shown below:

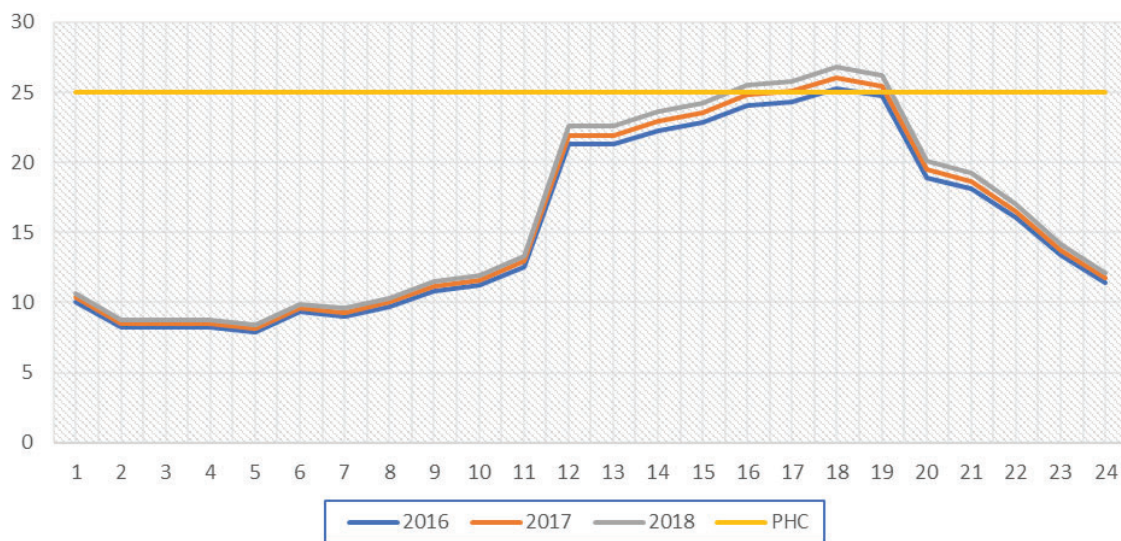
For this case study, a benefit-cost ratio (BCR) test would be most appropriate since the investment into a deferred investment would affect both the utility and ratepayers. A novel concept, i.e., considering “Storage as a transmission asset” (SATA), allows utilities to recover their investment through cost-based revenue recovery by adding the project to their rate-base, which can eventually show up on a customer bill as an extra charge for transmission. The benefit-cost ratio consists of benefits produced by the investment (here avoided cost of T&D investment and market revenues), and the total costs of the BESS include installed, fixed and variable costs, including federal tax incentives. BCR expressed as a net greater than one (1), means that the investment will have a positive impact on the utility’s resource acquisitions. Measures and programs that have a BCR less than one (1) are sometimes adopted because they have value for other reasons such as equity, emergency measures, etcetera. Some residential and low-income programs are examples

of programs that may not pass the BCR test but are still implemented.

The logic for assessing different battery power and energy capacities stems from the observation that different utilities would have different expectations on upgrade investment deferral. This depends on the risk-averse nature of the utility, meaning a more risk-averse utility would like to defer for a lower number of years and invest in T&D upgrades more quickly to meet the projected demand growth

reliably. The battery charge/discharge durations considered in the study are 4 hours and 5-hours due to larger capacity requirements for the ERCOT region due to higher than average load, although this depends on local requirements. The projected load growth rate is representative of the ERCOT region, which is undergoing rapid growth (2-3% growth per year). A higher battery size has been assumed to be selected for a higher projected load growth due to the requirement of more energy capacity.

**Figure 5. Load growth for the 69-kV test feeder during a typical peak demand day with a 3% projected load growth:**



The Figure above demonstrates how the load growth for the 69-kV test feeder during a typical peak demand day with a 3% projected load growth rate. This shows how the load exceeds the load-carrying capability or power handling capability (25 MW) of the distribution feeder post-2016.

## 4.0 RESEARCH DESIGN & METHODOLOGY

The methodology for this case study is focused on providing T&D deferral, although it has been shown in pilot studies that value-stacking with deferral as the primary use-case is possible. The most practical values available to be used with T&D deferral according to the knowledge of battery operation and market dynamics are real-time energy arbitrage and

voltage support, this is discussed in the later sections in more detail. The study is based on the evaluation of different scenarios of battery sizes (power and energy capacity) to defer T&D upgrades by:

1. Analyzing the load profile and power handling capability of a distribution feeder and identifying the peak demand days.
2. Initiating battery storage dispatch algorithm to charge during off-peak hours and discharge during on-peak hours (peak demand) when the demand > PHC of the line/substation.
3. Calculation of number of years that BESS can successfully defer upgrade investments and the benefit-cost ratio by assessing the net present values of “avoided cost” of traditional transmission upgrades and installed cost of BESS from recent DOE and industry reports.

4. Calculation of the number of years that BESS can successfully defer upgrade investments and benefit-cost ratios of BESS operation as both a “transmission” and “market” asset.

It is important to note that if the rated power and energy of the input storage system is larger than the estimated daily minimum to meet the deferral, then the upgrade can be deferred for the year. If partial deferral occurs, then the model outputs the number of hours that overload could not be avoided.

A growth rate is applied to the deferral load profile (load profile from the feeder) to estimate the number of years of successful years that asset upgrades can be deferred. This process repeats until the rated power and energy is lower than the estimated minimum. The corresponding year is recorded as the first year of failed deferral. For solving mixed linear programming (MLP) optimization problem before the first year of failed deferral, the following constraints are added to make sure the storage keeps the net power at the overloaded asset within bounds:

$$(1) \quad \text{maximport}_{\text{deferral}} \geq \text{load} - \text{battery charge} + \text{battery discharge}$$

$$(2) \quad \text{maxexport}_{\text{deferral}} \geq \text{load} + \text{battery charge} - \text{battery discharge}$$

Here ‘battery charge’ and ‘battery discharge’ are optimization variables in the StorageVET Python environment.

For battery optimization under hybrid operation as a transmission and market asset, StorageVET allows the selection of multiple grid services, although the code was modified to only operate on the real-time markets with priority to T&D deferral. The algorithm for energy arbitrage, i.e., buy low and sell high, was utilized for these months, and the profit was calculated as the difference of discharge revenue and charging cost by utilizing historical ERCOT West prices. The model is robust to identify peak overload scenarios in a week-ahead timeframe and limits arbitrage to accommodate discharge during overload periods. Battery replacement costs are not included in the analysis to avoid complexity but will play a role when considering hybrid operation due to increased battery cycling-related degradation.

In typical radial distribution systems, the power is delivered from the substation to the end-users through dedicated feeders. Each feeder has a recommended apparent power limitation. This limit is defined mainly by the feeder conductor size and allowable sag. A feeder upgrade is required when the demand exceeds feeder capacity, or the sagging of overhead conductors reduces the clearance below the minimum required value (Zhang et al., 2016). A different upgrade situation would be caused by the feeder load exceeding the transformer kVA rating. A BESS could also potentially permit transformer upgrade deferral. Feeder upgrade planning is driven by projections of the magnitude and duration of

peak loads, which typically follow daily, weekly, and seasonal patterns, as shown in Figure 6 below.

#### 4.1 Model Assumptions and Limitations:

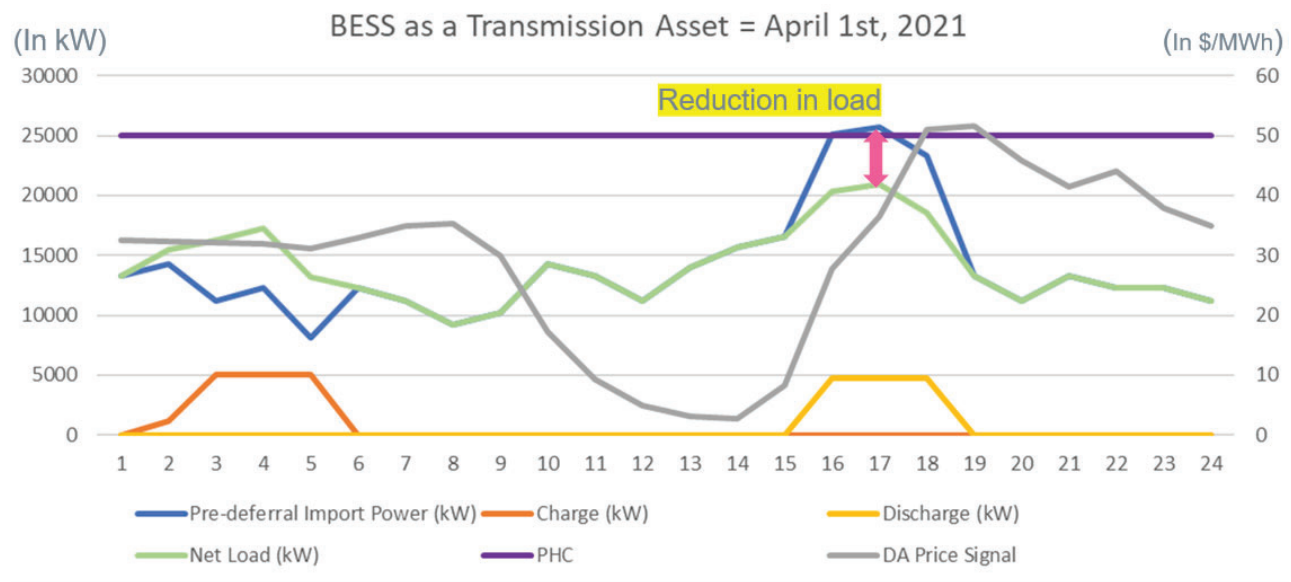
1. Batteries are assumed to last till the entire duration of deferral for transmission cases while a single replacement is considered for ‘transmission + market’ (T+M) operation. Also, it is assumed that T&D upgrades will inevitably have to be implemented after ‘ $t_p$ ’ years of deferral to ensure long-term reliability.
2. The load growth rate for a scenario is applied to all the subsequent years and is not variable for a scenario. In the real world, the load growth understandably would change each year due to block load additions and other reasons.
3. Battery charging costs are assumed to be negligible in the “transmission” case since the batteries are only being utilized for fewer than 100 hours for the entire year and these costs can be recovered through a rate recovery arrangement.
4. The discount rate and loan repayment periods are representative of actual industry metrics but are subject to change on a case-case basis.

5. A successful deferral year does not consist of even a single hour of line overload.
6. The incremental monthly benefits of the first year of failed deferral are not accounted for in the calculations of the economic benefits. Only the benefits accrued till the whole last year of successful deferral are being considered.
7. The BESS optimization model for operation in the day-ahead/real-time market has perfect week-ahead foresight of the market prices and daily load curves.

## 5.0 ANALYSIS & RESULTS

A preliminary analysis of electric load data for the 25 MW distribution feeder showed that the overload period was usually occurring for the 3-hour period during peak demand days. To alleviate this overload period, battery discharge durations of 4 hours are considered in this case study. Three sizes of BESS: 3 MW/12 MWh, 5 MW/20MWh, and 7 MW/28 MWh were considered with three different load growth scenarios of 1%, 2%, and 3% in the region which are representative of ERCOT load growth possibilities. On simulating this battery model on StorageVET, the output values are the hourly battery dispatch of the last year of successful deferral as well as the first year of failed deferral based on the energy capacity of the BESS.

**Figure 6. Battery charging, discharge and load reduction for the test 5 MW/20 MWh BESS for a forecasted overload day in 2021 operating in pure transmission mode.**



The output, i.e., last year of “complete” successful deferral is the input into a techno-economic model developed in MS Excel which accounts for BESS installed costs, feeder upgrade costs and representative discount and loan repayment rates to evaluate the net present values of investment for both the options which is eventually utilized to evaluate the benefit-cost ratio of the investment deferral.

### 5.1 Benefit–Cost Ratio Calculation Methodology:

The benefits of distribution-system-connected energy storage are typically measured concerning the value obtained by the utility owner and operator (Kleinberg et al.,2014). This can be expressed in terms of the value of the “avoided cost” of feeder/substation equipment upgrade and market revenues, if any. The capital cost for a BESS can be divided into two main parts. The first one is

the cost of the power conditioning system and its auxiliaries denoted as the “power” component with unit price in Million \$/MW. The other one is the “energy” component, representing the cost of the actual storage components with unit price in M\$/MWh. The total installed cost of the battery is the summation of power and energy components. To calculate the overall cost of operation of BESS over the deferred year, annual operating expenses (in \$/year), which consists of the fixed and variable O&M costs are added to the installed costs.

The cost components and respective values of Li-ion battery systems have been obtained from NREL’s 2018 PV-BESS cost benchmarks (Fu et al., 2018). The capital cost for the feeder upgrade is a function of the upgraded feeder length. It can be calculated as the product of upgraded feeder length (in miles) and price of feeder upgrade (in \$/mile). The case study assumes the upgrade of a 69-kV overhead line to an underground feeder line. Brown (2009) estimated that undergrounding local overhead distribution lines would cost ~\$1 million per mile, but to account for labor and other administrative expenses, \$1.50 million per mile is assumed to be a reasonable estimate. For comparison, the minimum replacement costs for existing overhead distribution

lines ranged from \$86,700 to \$126,900/mile, with maximum replacement costs ranging from \$903,000 to \$1,000,000 (Larson et al., 2016). The respective cost values were inputted to the benefit-cost model developed to calculate the benefit-cost ratios for different scenarios of BESS deployment.

The method to determine the techno-economic benefit-cost ratio of feeder upgrade deferral is to compare the net present values (Zhang et al., 2016) of the following at the year  $t$  till the last year of successful deferral at year  $t_p$ :

The construction of an additional feeder at the future time  $t_f$  when the load grows beyond the original feeder capacity limitation ( $PV_{feeder}$ ) plus any market revenues obtained from BESS operation in the day-ahead or real-time market ( $PV_M$ ).

The installation ( $PV_B$ ) and total operational cost of a BESS ( $PV_{BOC}$ ) at the time  $t_p$  plus the deferred time  $t_f$  years of new feeder construction at a future time a year following  $t_p$  at a discount rate ‘d’ (typically 7-8%).

$$(3) \quad BCR_{t=t_p} = \frac{PV_{feeder} + PV_M}{PV_B + PV_{BOC} + \frac{PV_{feeder}}{(1+d)^{t_p}}}$$

**Table 1: Last year of successful deferral and benefit-cost ratios for multiple test scenarios assuming BESS only as a “transmission asset.”**

| Scenario | BESS Specification<br>Power & Energy<br>Capacity | Load<br>Growth<br>Rate % | Last Year of<br>Successful<br>Deferral (Base<br>Year – 2018) | Benefit-Cost Ra-<br>tio based on NPV<br>Analysis (at $t_p$ ) | Benefit (\$/kWh) |
|----------|--------------------------------------------------|--------------------------|--------------------------------------------------------------|--------------------------------------------------------------|------------------|
| S1       | 3 MW, 12 MWh                                     | 1%                       | 2026                                                         | 1.44                                                         | \$493/kWh        |
| S2       | 3 MW, 12 MWh                                     | 2%                       | 2021                                                         | 1.15                                                         | \$212/kWh        |
| S3       | 3 MW, 12 MWh                                     | 3%                       | 2020                                                         | 1.08                                                         | \$128/kWh        |
| S4       | 5 MW, 20 MWh                                     | 1%                       | 2027                                                         | 1.34                                                         | \$247/kWh        |
| S5       | 5 MW, 20 MWh                                     | 2%                       | 2023                                                         | 1.12                                                         | \$63/kWh         |
| S6       | 5 MW, 20 MWh                                     | 3%                       | 2022                                                         | 1.01                                                         | \$17/kWh         |
| S7       | 7 MW, 28 MWh                                     | 1%                       | 2039                                                         | 1.28                                                         | \$152/kWh        |
| S8       | 7 MW, 28 MWh                                     | 2%                       | 2024                                                         | 1.10                                                         | \$89/kWh         |
| S9       | 7 MW, 28 MWh                                     | 3%                       | 2023                                                         | 0.91                                                         | -\$32/kWh        |

Table 2: Last year of successful deferral and benefit-cost ratios for multiple test scenarios assuming BESS as a “transmission asset” with operation in the real-time energy market.

| Scenario | BESS Specification<br>Power and Energy Capacity | Load Growth Rate % | Last Year of Successful Deferral (Base Year – 2018) | Benefit-Cost Ratio based on NPV Analysis (last year of successful deferral) | Benefit-Cost Ratio for “T+M” Operation |
|----------|-------------------------------------------------|--------------------|-----------------------------------------------------|-----------------------------------------------------------------------------|----------------------------------------|
| S1       | 3 MW, 12 MWh                                    | 1%                 | 2026                                                | 1.44                                                                        | 2.31                                   |
| S2       | 3 MW, 12 MWh                                    | 2%                 | 2021                                                | 1.15                                                                        | 1.85                                   |
| S3       | 3 MW, 12 MWh                                    | 3%                 | 2020                                                | 1.08                                                                        | 1.44                                   |
| S4       | 5 MW, 20 MWh                                    | 1%                 | 2027                                                | 1.45                                                                        | 2.95                                   |
| S5       | 5 MW, 20 MWh                                    | 2%                 | 2023                                                | 1.12                                                                        | 2.01                                   |
| S6       | 5 MW, 20 MWh                                    | 3%                 | 2022                                                | 1.01                                                                        | 1.97                                   |
| S7       | 7 MW, 28 MWh                                    | 1%                 | 2039                                                | 1.28                                                                        | 4.7                                    |
| S8       | 7 MW, 28 MWh                                    | 2%                 | 2024                                                | 1.10                                                                        | 3.1                                    |
| S9       | 7 MW, 28 MWh                                    | 3%                 | 2023                                                | 0.89                                                                        | 2.95                                   |

Based on the analysis shown in Tables 1 and 2 above, there is a clear tradeoff between the years of required deferral and economic viability of BESS, i.e., benefit-cost ratios. If opting under pure “transmission” operation, a higher benefit-cost ratio does not necessarily signify a more economical alternative since the number of deferred years may be lower, which may be against the utility’s planning objectives for the service area. Battery capital costs and feeder upgrade costs are significant drivers in assessing deferral benefits. As BESS costs reduce further due to technological advancements and economies of scale, the analysis results may change moving towards more favorable economics for larger sized BESS configurations. Increasing BESS capacity leads to more years of deferral. However, higher capital costs offset the deferral benefits leading to lowering BC ratios for a considerable number of years before reaching breakeven compared to smaller sized BESS. Another insight obtained from this study is that under low load growth, it is much more economically viable to go for a smaller sized BESS (as shown in Fig) to ensure the capital costs do not exceed deferral benefits over the deferral period.

Even under a high load growth scenario, it is more economically viable to implement a lower sized BESS considering eventual feeder construction after ‘ $t_p$ ’ years. When load growth is minimal, hybrid-operation as a transmission and market asset is more profitable for larger-sized battery configurations because storage operation as a transmission complements operation in the real-time energy market leading to significant revenues. The revenues are even higher if the price volatility in the energy market is high, but battery replacement costs must be accounted for due to more frequent battery cycling under arbitrage operation.

When load growth increases over 2%, it is more prudent to have dedicated BESS to ensure transmission assets do not interfere with battery charge-discharge cycles and to limit battery degradation. Hybrid operation as a market asset (day-ahead or real-time) adds revenue leading to a substantial increase in benefit-cost ratios, which are possible for the future if sufficient battery optimization techniques are formulated. It is also necessary to implement relevant market mechanisms to notify storage operators for SATA or Market operation on a day-ahead basis such that battery

charge-discharge cycles are not affected in hybrid operations leading to overload or loss of revenues. This may be in the form of a load-based notification test pursued by CAISO. It has been discussed in the later sections.

## 5.2 Opportunities and Challenges

Apart from the traditional usage of batteries to store off-peak energy and discharge during peak demand times, i.e., energy arbitrage or time-shifting, there are several other opportunities for BESS to be employed for key grid applications. Although the value of these services may not be quantified completely in the present market and regulatory structure, these benefits offer utilities a cost-effective solution to a variety of grid issues ranging from high capital costs to congestion. Three major opportunities have been mentioned below:

### 5.2.1 Modularity

A significant advantage of BESS as a transmission asset is its modularity and transportability. A potential business model that a utility or transmission operator can consider is transferring BESS physically to different areas for upgrade deferral or any other ancillary purposes inside its service territory area where issues such as peak load growth, low power quality or reactive power injection can be treated. Grid battery systems are extremely modular. Cells are assembled into *modules*, and then the modules are mounted into cabinet *racks* (mostly 19-inch), and racks are installed into a standard-sized *container* (mostly 40 feet long) (Hesse et

al.,2017). A typical container usually stores 1-5 MWh of energy. A large battery plant is essentially a bunch of containers synchronizing to provide energy and capacity services. This modularity is not only good for BESS customization, but also the control and maintenance down to the single-cell level. It also buys significant time for the utilities to assess the demand profile of a service territory for a future line or substation upgrades.

### 5.2.2 Value Stacking with Complementary Services

As of now, batteries utilized as transmission assets are not allowed to operate in the wholesale market due to the current regulatory structure of ISO/ RTOs. Some transmission operators such as CAISO and MISO have initiated proceedings to formulate rules regarding the hybrid operation of storage for transmission and market purposes. An important aspect of considering value-stacking for BESS with the primary use of peak-shaving which can defer upgrade investments in existing lines, feeders or substations is the “compatibility” of the secondary use-case with the primary use case.

### 5.2.3 Integration with PV

Integrating BESS with on-site PV can provide additional flexibility and revenue streams for a utility deferring T&D upgrade. The dispatch algorithm for the PV-BESS can be adjusted to include PV generation during daylight hours or can be adjusted

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to store PV-based energy in the storage to dispatch during peak demand hours finally. Eq (1) and (2) can be changed as:

$$(4) \quad \text{maximport}_{\text{deferral}} \geq \text{load} - \text{battery charge} + \text{battery discharge} - \text{PV generation}$$

$$(5) \quad \text{maxexport}_{\text{deferral}} \geq \text{load} + \text{battery charge} - \text{battery discharge} - \text{PV generation}$$

Although the added cost of PV may prove to be a deterrent initially, PV combined with storage is eligible for tax deduction under US’ Business Investment Tax Credit or commonly known as ITC which reduces 30% of the capital cost of the combined system in the form of a tax deduction for the utility or tax equity investor. Currently, projects which would start construction before December 31<sup>st</sup>, 2020, are eligible for a 30% deduction, which will eventually be faded to 22% after 2022. An important caveat here is that to become eligible for the tax credit under this law, and the BESS must be charged entirely from the PV system attached to it, or else the 30% credit drops down to the % of energy charged using solar energy. Also, the charging cost reduces when PV is supplying energy to the BESS. To potentially utilize hybrid systems

for T&D deferral, additional studies need to be conducted to analyze the resource potential and variability of solar energy in the region to ascertain whether it would be technologically viable or not. In areas where peak demand periods coincide or succeed hours with high solar output potential, hybrid systems may offer an attractive opportunity to reduce charging costs from the grid as well as defer capital investments on upgrading T&D infrastructure such as feeders, transformers etcetera.

Energy storage systems have the potential to disrupt the electric grid as we know it for years to come due to its expanding growth, falling costs, and awareness among policymakers and industries. To achieve that, the storage ecosystem needs to be aware of some key challenges which can decelerate the phenomenal growth it has seen over the last decade. These barriers and challenges have been mentioned below.

### **5.3 Irregular Demand Forecasts**

A major challenge for utilities investing in storage systems for T&D deferral would be to assess the demand forecast for upcoming years to design and dispatch the battery system accordingly. Across the US, electricity demand has slowed in some places (PJM) and exploded in other areas (ERCOT) due to a variety of reasons such as increasing demand response measures and rapid residential and industrial growth. The role of emerging technologies like energy efficiency, industrial demand response, and explosive growth of the EV industry will create problems for utilities to predict load across their service territories due to the intermittent nature of the demand. Utilities had struggled with flat demand for the last decade, but analysis by the National Renewable Energy Laboratory (NREL) predicts steady growth across the next three decades, largely driven by the adoption of electric vehicles. Although a challenge, the flexible nature of BESS will eventually help the electric grid in providing energy during peak demand times when other supply options can't be ramped up. For this to happen, better algorithms and optimization models need to be developed to keep the technical characteristics of the battery and the grid in mind to adjust for uncertain situations.

### **5.4 Uncertain electricity market design and regulatory framework**

One of the major barriers present in the US markets is the classification of electrical energy storage systems as a “generation asset” by federal authorities. Energy storage resources are technically capable of providing services in each of the functional classifications of generation, transmission and distribution (T&D) of electricity. Although recent FERC rulings (FERC Order. 841) have allowed ISO/RTOs to formulate regulations on allowing energy storage to participate in the energy and ancillary markets effectively, there still remains concerns on the T&D side due to lack of federal guidance on how to deploy storage as transmission asset (FERC Order 1000). Regulatory restrictions, along with accounting practices and requirements and the lack of clarity and transparency in these practices and requirements, effectively prevent a utility or developer from obtaining revenue with a resource providing service under multiple classifications. These issues are particularly prevalent in ISO/RTO regions in the US since, in non-ISO/RTO, a vertically integrated utility can recover the costs and profit by delving into all the value streams possible in each functional classification.

### **5.5 Material and Operational Safety**

Although the adoption of storage has been increasing, safety codes and standards for storage are still under development, and questions have been raised about safety risks and how to mitigate those risks, according to a recent government study (Rusco, 2018). Efforts are underway to ensure that safety codes and standards address energy storage systems, but these types of standards tend to lag behind the development of storage technologies.

In addition, concerns about the operational safety of large storage systems as a fire hazard can be a barrier to their deployment in urban areas or proximity to other grid resources such as substations, and local entities such as city EHS and fire departments may not allow the deployment of storage on certain sites. This happens when an electrical short develops inside the cell, causing a thermal runaway rendering the external protection ineffective in nullifying

this threat. For the lithium-ion battery runaway, it is caused by the exothermic reactions between the electrolyte, anode and cathode, with the temperature and pressure increasing in the battery, the battery ruptures (Wang et al., 2012). Since 2012, there have been three instances of fire explosions involving BESS, most recently in APS' 2 MW facility outside Phoenix, AZ.

A major issue brought to the fore from these experiences is that local jurisdictions and emergency responders, along with storage system installers, insurers, and others may not have a complete understanding of the hazards associated with storage and best approaches to addressing these hazards, such as the appropriate fire protection measures. Besides, local entities' review of energy storage systems, for example, can add additional time to the permitting process, given that these entities may not be familiar with storage systems and potential safety concerns. Although stricter standards are required for battery packs to lower the risk associated with electric short-circuiting, another important aspect is research on effective ways to educate firefighters to douse battery fires efficiently.

## 6.0 CONCLUSION & POLICY IMPLICATIONS

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The strongest impacts on deferral benefits are the capital costs of the storage battery and the feeder upgrade, followed by other factors like the rate of load growth/increase and loan durations for BESS and feeder. Larger BESS sizes lead to more deferred years, but since capital costs of BESS are high, this leads to lower benefit-cost ratios and longer payback periods when storage is operated only as a transmission asset. It is also important to understand that factors such as utility objectives specified in the IRPs or transmission plans dominate the decision-making process to decide whether to invest in upgrades or not. So, if a utility is more inclined to defer for a larger period, then storage configuration can be optimized accordingly. In terms of techno-economic viability and long-term needs, it is better to utilize a smaller sized BESS, especially under low growth scenarios, as shown by the analysis results. Although utilities are allowed to recover

costs from rate recovery, it is prudent to consider that utilizing storage would improve their financial situation. On the other hand, larger battery sizes are significantly more profitable when storage acts as both a transmission and market asset due to market revenues, but the charging/discharging cycles need to be optimized carefully so as not to hinder with the primary value-stream of application, in this case, i.e., transmission asset to reduce overload periods. The recent regulatory implications discussed below offer a solution for storage to act as both a transmission and market asset, which would propel utilities/transmission operators to implement larger battery sizes.

Energy storage is often presented as a solution to the challenges utilities face in trying to promote clean energy resources, which reduce the effects of global warming and climate change. The U.S. Energy Storage Monitor Q4 2018 estimates that installations totalled 338 megawatts in 2018, and will grow to 3.9 gigawatts by 2023, much of it front-of-the-meter utility-scale projects. Despite this growth, most utility-scale battery installations are occurring in vertically integrated utility service areas outside of the organized power markets serving two-thirds of all U.S. electricity consumers. Storage can indeed encourage the penetration of intermittent and variable renewable energy resources through its time-shifting characteristics. A corollary to the assumption that storage is necessary for the integration of clean energy resources is that storage would also lead to a reduction of greenhouse gas emissions because it can store the excess energy generated at times of low market demand and inject it to the grid at a later time, reducing the need for generation from fossil-fuel-powered bulk system generators (Condon et al., 2018).

Other than FERC activities described in the previous sections, to date, federal policies involving energy storage have been limited, and most policy actions involving energy storage have been at the state level. State-level policy actions include setting procurement mandates, establishing incentives, and requiring incorporation of storage into long-term planning mechanisms such as integrated resource plans (IRPs) that demonstrate each utility's ability to meet long-term demand projections using a combination of generation, transmission, and

energy efficiency investments, while minimizing costs (US EIA, 2018). Recent policy discourse on integrating energy storage resources to the electric grid has revolved around regulatory hurdles inhibiting its deployment in multiple organized markets across the US. Even in vertically integrated markets, storage has been stifled due to the inability of the utilities to define storage value, particularly questions like “how to ask for storage in RFPs?”. As shown through this study, positive benefit-cost ratios and investment deferral has the potential for utilities to save money and increase expenditure in the proliferation of renewable energy systems.

The real challenge lies in formulating an effective structural framework to integrate multiple services for BESS and streamline the cost allocation process. This may involve allowing BESS to be classified as a generator, load as well as a transmission asset. The need of the hour is a separate classification scheme for energy storage assets to value all these services fairly and reasonably. SATA with market operation can provide a huge boost to utility revenues and save billions of dollars in the avoided cost of upgrade investment if and only if RTO/ISOs come up with structural changes to their market operations. CAISO has taken progressive steps in this regard by initiating a scheme for SATA to recover costs and operate in the real-time and day-ahead market through policy proceedings for developing rules and regulations for SATA operation. MISO also opened proceedings for considering storage as a transmission asset in 2018, although it has made little headway in formulating actionable steps due to push back from state legislators. Federal and state policymakers must understand the benefits to the utilities as well as ratepayers that can be accrued from utilizing energy storage options and take concerted action towards formulating policies supporting their deployment rather than looking at obsolete options for transmission and distribution investments.

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