
The Value of Distributed Electricity Storage in Texas

Proposed Policy for Enabling Grid-Integrated
Storage Investments

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Executive Summary

Electricity storage is attracting much attention as storage manufacturers begin to announce rapid reductions in the technology's costs, utilities publicize upcoming deployments, and states evaluate new policy initiatives.¹ Interest in electricity storage is driven by a range of potential applications that include avoiding power outages for customers, reinforcing the grid, reducing other transmission and distribution (T&D) costs, shifting power consumption away from costly peak-load periods, balancing intermittent renewable energy resources, and providing ancillary services and emergency response services in the wholesale power markets. While the potential value of these and other storage applications have long been recognized, electricity storage costs have not been competitive with alternative technologies and resources that can provide comparable services. Therefore, electricity storage investments to date have been deployed primarily as demonstration projects.

Now, it appears that electricity storage is on the verge of becoming economically attractive. Battery storage manufacturers and industry reports indicate that costs will decrease substantially over the next few years. Current forecasts estimate cost declines from the current \$700–\$3,000 per kWh of installed electricity storage in 2014 to less than half of that over the next three years.² Some analyst projections and vendor quotes indicate that the installed costs of battery systems will drop to approximately \$350/kWh by 2020.³ At these much lower costs, many innovative applications of electricity storage could become cost effective.

In this context of declining battery costs, Oncor Electric Delivery Company (Oncor), a Transmission and Distribution Service Provider (TDSP) in Texas, has engaged us to explore the economics of grid-integrated storage deployment in Texas. We evaluate this question first by examining the many potential value streams of storage, including those achieved in the T&D systems and those achieved through participation in wholesale energy and ancillary services markets. We then evaluate whether and at what deployment levels storage can be cost-effective from the perspectives of wholesale electricity market participants, retail customers, and the combined system or society as a whole.

¹ For example, see Public Utility Commission of the State of California (2013), p. 2.

² Navigant notes that current storage costs for a four-hour battery are \$720–\$2,800/kWh depending on the scale of the battery. According to Sam Jaffe of Navigant Research, battery-only costs are currently around \$500–700/kWh with the remaining installation costs due to system costs. Also see Dumoulin-Smith, *et al.* (2014), p. 1.

³ The \$350/kWh installed cost projection is based on Oncor's discussions with vendors, consistent with industry sources. For example, Morgan Stanley predicts that battery-only costs may reach \$125–\$150/kWh in the near future, down from the \$500/kWh currently. See Byrd, *et al.* (2014), p. 40. If battery costs are capable of reaching the low costs projected by Tesla Motors Inc., this would imply a battery-only cost of \$110/kWh. See Jaffe (2014), p. 30.

We then evaluate whether new business models and public policies supporting those electricity storage business models in Texas would be needed and appropriate, given the Electric Reliability Council of Texas's (ERCOT's) deregulated market structure, and if so, what policies might be necessary for Texas to realize the full economic and reliability benefits of grid-integrated, distributed electrical energy storage.

Overall, our analysis shows that deploying electricity storage on distribution systems across Texas could provide substantial net benefits to the state. We estimate that up to 5,000 MW (15,000 MWh, assuming a three-to-one ratio of storage to discharge capability) of grid-integrated, distributed electricity storage would be cost effective from an ERCOT system-wide societal perspective, based on a forecast of installed cost of storage of approximately \$350/kWh. Our analysis assumes that the storage deployment plan and the business model enabled by public policy will be developed to capture as many benefits as possible by integrating value from increasing customer reliability, improving the T&D systems, and transacting in the wholesale power markets.

Our analysis accounts for the net impact that deploying storage would have on generation investments in ERCOT's "energy-only" wholesale electricity market. We show that adding 5,000 MW (or 15,000 MWh) of storage would reduce the need for new generation by approximately 3,100 MW. This generation investment response **sustains market prices high enough to fully support the development of the additional new generating capacity necessary to maintain resource adequacy in ERCOT.** Our market simulations also show that integrating storage into the ERCOT market reduces price spikes during the most severe scarcity events, resulting in fewer high-priced scarcity hours, but increases prices during non-scarcity peak hours and during the lowest-priced off-peak hours. As a result, conventional generation plants recover their fixed costs during more hours of the year and in somewhat more predictable fashion than on the system without storage.

We also evaluate the benefits of grid-integrated storage deployed by TDSPs from an average electricity customer's perspective. Our analysis shows that deploying 3,000 MW (9,000 MWh) of storage across ERCOT (with 1,000 MW on Oncor's system) would reduce residential customer bills slightly and provide additional reliability benefits in the form of reduced power outages for customers located in areas where storage is installed. **Considering both the impact on electricity bills and improved reliability from grid-integrated storage, total customer benefits would significantly exceed costs.** However, while beneficial from an integrated, system-wide perspective, an efficient scale of storage deployment would not be reached if deployed solely by merchant wholesale market participants, by retail customers, or only for capturing T&D benefits.

Storage investments could not be undertaken at an efficient scale solely by merchant developers in the Texas restructured electricity market because the value that a merchant storage developer can monetize through transacting in the wholesale power market alone is too low compared to costs. For instance, we find that approximately 30–40% of the total system-wide benefits of storage investments are associated with reliability, transmission, and distribution functions that are not reflected in wholesale market prices and, therefore, cannot be captured by merchant storage investors. Even at the low projected storage costs, the opportunity to arbitrage wholesale

power market prices and sell ancillary services would not likely attract merchant storage investments at the efficient scale. This means that relying only on merchant investors to develop storage in ERCOT would result in under-investment in storage from a state-wide perspective. Moreover, without being integrated in T&D planning and operations, merchant electricity storage would be under-utilized and unable to capture the high additional value offered by targeted deployment within the transmission and distribution systems.

Similarly, while individual customers would be able to capture the backup-power benefits of storage, they are not likely to directly monetize the larger grid-wide and wholesale power market benefits. Finally, developing storage to capture only the T&D system benefits would likely result in under-investment and under-utilization of electricity storage for wholesale power applications.

In contrast, deploying storage in a manner that can be integrated into the distribution system and also capture wholesale market benefits would allow TDSPs to capture high-value applications such as providing backup power and voltage support on distribution feeders with below-average reliability or high-value end uses; reducing wear on critical distribution assets; and deferring T&D investments. Given that deploying storage on specific locations on the distribution system is important for capturing the full value of benefits that storage can provide, a grid-based deployment strategy will be most effective if it is integrated with: (1) planning transmission and distribution system investments; and (2) targeted efforts to use electricity storage backup to reduce customers' distribution-system-related power outages. In addition, to capture the full value of distributed storage assets would require that they be dispatched into the wholesale power markets.

Given the significant benefits that storage can bring to the system as a whole, enabling cost-effective investments in electricity storage will require a regulatory framework that helps investors capture both the wholesale market and the T&D system values associated with the storage devices. We identify a range of policy options and business models for enabling cost-effective storage without relying on subsidies that would create a net cost for ratepayers or taxpayers.

Because allowing TDSPs to integrate storage with its transmission and distribution planning will help capture storage's benefits and concerns related to this approach can be mitigated, we focus on the policy framework that would involve: (1) enabling electricity storage investments to be deployed by TDSPs on their systems as part of T&D planning that seeks to capture T&D and reliability-related values; and (2) allowing independent wholesale market participants to offer the storage devices into the wholesale power market. This regulatory framework would involve allowing the transmission and distribution companies to "auction off" to independent third parties the wholesale market dispatch of the electricity storage deployed on the T&D system. This approach would maintain the clear delineation between the TDSP's role as a T&D service provider and wholesale market participants who transact in the market. The auction proceeds would be used as an offset to retail customers' T&D costs, which include paying for the storage facilities. Such a regulatory framework would facilitate an economically-efficient level of storage investments in Texas, and reduce investment barriers by allowing the storage technology to be

deployed when the combined benefits from the wholesale market, transmission, and distribution systems exceed the expected costs by a sufficient margin.

The focus of this study is limited to: (a) analyzing the potential economic benefits of electricity storage; (b) assessing the likely market size for cost-effective storage in ERCOT; and (c) recommending a high-level regulatory framework to support such a cost-effective deployment. We have not yet analyzed which of the different electricity storage technologies might be suitable to capture most of the identified value, nor have we evaluated how different usages of the storage devices might affect the costs. Additional work will be needed to develop a phased-in deployment plan and demonstrate the cost effectiveness of any proposed plans. The details of a regulatory structure and a roadmap of various approval processes and safeguards to support a successful deployment of storage assets will also need to be developed.

I. Introduction and Background

Oncor Electric Delivery Company (Oncor), a Transmission and Distribution Service Provider (TDSP) in Texas, engaged us to explore the economics of grid-integrated, distributed storage in Texas. We evaluate this first by estimating whether and to what extent storage could be cost-effectively deployed on distribution systems in the state from the perspectives of retail customers, wholesale electricity market participants, and the combined system or “society as a whole.” We then evaluate the merits of different business models and whether new public policies would be needed to support electricity storage in Texas, given the Electric Reliability Council of Texas’s (ERCOT’s) deregulated market structure, and if so, what policies might be necessary to realize the full economic and reliability benefits of grid-integrated, distributed electrical energy storage.

This report is organized as follows. Section I discusses the different perspectives that can be applied to measure the value of electricity storage and provide a summary of the types of individual benefits that can contribute to the overall value of adding storage to the electricity system. Section II reviews and summarizes recent industry studies on this subject area. Section III presents the analytical approaches used to estimate the values that deploying grid-integrated storage in ERCOT can provide on a system-wide basis. Section IV presents the estimated merchant value of storage in ERCOT as well as the aggregate value grid-integrated storage (including transmission, distribution, and reliability benefits) from both system-wide societal and retail customer perspectives. Section V summarizes our overall findings and discusses their implications. And finally, Section VI explores possible business models and regulatory policies that could be implemented to enable economic storage investment in ERCOT and operationally and financially unbundle the regulated and competitive uses of the storage devices.

A. PERSPECTIVES FOR MEASURING THE VALUE OF ELECTRICITY STORAGE

One of the major differences between electricity and other energy sources such as oil and gas is that electricity supplies must be balanced with consumption at all times. Aside from parts of the country (and world) where pumped hydro storage is abundant, there has been very little ability to economically store excess electricity supplies and discharge the power back into the grid when needed.⁴ Depending on the technology, electricity storage can provide a number of services to

⁴ The grid-level storage of electricity is not a new concept. However, as of today, pumped hydro is the only form of storage that has seen widespread deployment in electricity markets throughout the U.S. Although it is severely restricted by geography, there are currently 36 pumped hydro facilities in the U.S. with a combined capacity of approximately 20,000 MW, see DOE Global Energy Storage Database (2014). Other forms of storage, such as batteries, have two major advantages over pumped hydro: (1) they are not restricted by geography, and (2) they can be deployed at a smaller scale. If costs can

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the grid beyond what is known as “energy arbitrage” or charging when demand is low and discharging when demand is high. Some of these other applications include providing ancillary services as storage can be fast-acting in response to a grid emergency; deferring the need for transmission and distribution (T&D) investments; and, improving reliability by providing discharging power during an outage.

Due to recent technological developments, it appears that electricity storage is becoming economically attractive. In fact, industry projections indicate that battery costs may fall to half of their current levels by 2020. Large storage additions have the potential to greatly change the dynamics of the grid and the roles of generators, T&D utilities, and grid operators. As costs of grid-level electricity storage decline, many innovative applications could become cost effective. In this report we quantify a selection (but not all) of these potential benefits, and compare them to the costs of deploying storage.

When evaluating the benefits of electricity storage, it is important to establish from whose perspective the benefits are measured. From the perspective of a wholesale market participant, the primary question is whether the benefits of merchant participation in the ERCOT electricity markets exceed investment costs. From the perspective of T&D providers and their ratepayers, it is important to evaluate the benefits that T&D customers would receive in comparison to the costs they would incur. Finally, from the perspective of policy makers, it is most relevant to compare the system-wide benefits with system-wide costs as the primary metric, although the impacts on and the value implications for electricity customers, generators, regulated T&D companies, and other market participants must all be considered.

The definition and significance of these three distinct perspectives are described below and summarized in Figure 1:

- **Merchant Benefits** are the net profits that a private investor could monetize by participating in the wholesale markets for electric energy and ancillary services. The net merchant value is the most relevant metric from a wholesale market participant’s perspective because one would make the storage investment only if one can obtain adequate profit from it. As we will discuss in more detail later, if the capital expenditure of the storage were paid for by electricity customers through regulated cost recovery, the merchant value could be captured and shared with customers to reduce their electricity bills.
- **“System-Wide” or “Societal” Benefits** are the overall benefits of storage to the electricity system as a whole, regardless of whether those benefits and costs accrue to the asset owner, retail customers, market participants, or other entities. After subtracting the costs of electricity storage, the net societal benefits indicate whether the investment in storage would be in the overall public interest. This

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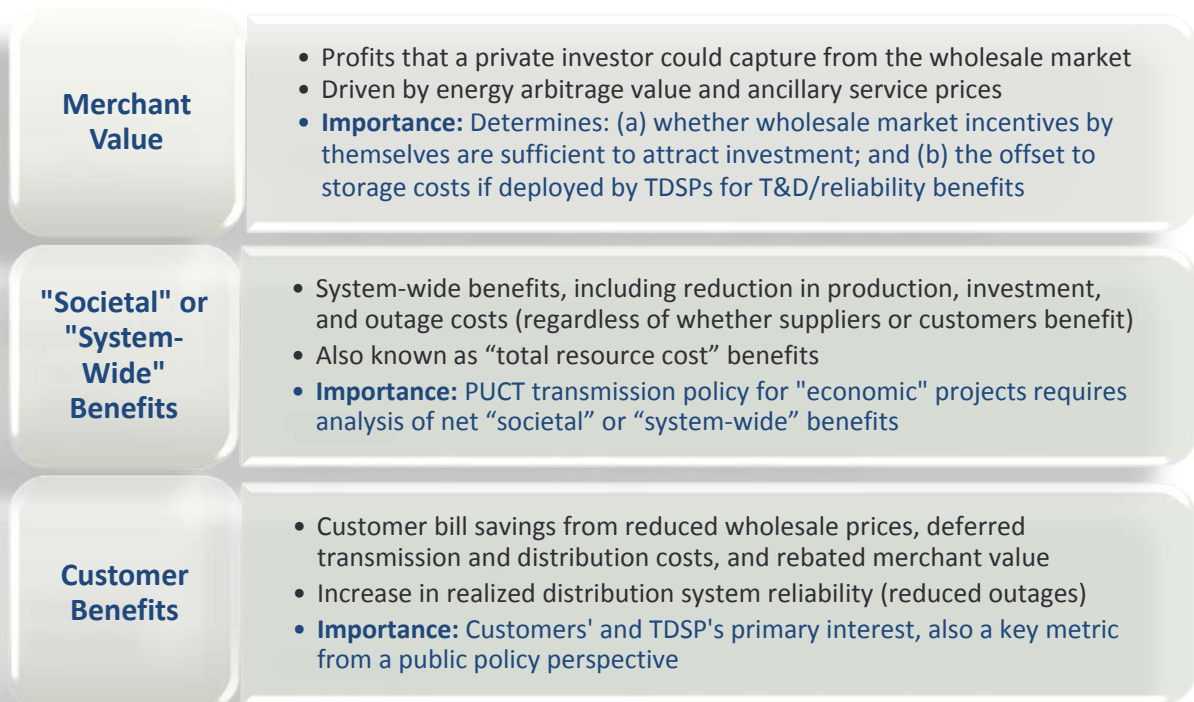
be reduced, electricity storage can dramatically change how energy storage is viewed for grid deployments.

system-wide benefits perspective is the most common metric on which policy-makers and regulators rely in making policy choices. It is also the metric used in Texas for evaluating the economics of transmission investment decisions, as codified in the Public Utility Commission of Texas’s (PUC’s) decisions.⁵

- **Customer Benefits** are the benefits that accrue directly to electricity users. In the context of electricity storage deployment, these benefits may include lower electricity bills, improvements in reliability for customers that can take advantage of storage as a backup power source, and improved power quality due to storage’s ability to control voltage. Net customer benefits (after accounting for the costs incurred) are likely to be the most important metric for ERCOT TDSPs and their customers when determining whether a capital expenditure should be made and added to a TDSP’s rate base.

We evaluate the magnitude of potential benefits from each of these three perspectives compared to anticipated costs, when determining whether and how Texas can benefit from electricity storage investments.

Figure 1
Three Perspectives on Measuring the Value of Electricity Storage



⁵ See PUCT (2012).

The potential value of storage from each perspective and in aggregate depends greatly on how that asset is deployed and operated. Because storage can provide value in both the regulated and competitive segments of the electricity market, in a fully deregulated market like ERCOT, a number of regulatory challenges present themselves. Conversely, without a proper regulatory framework, storage values may not be captured in a deregulated and therefore, segmented market place.

Acknowledging these challenges, the regulatory framework under which energy storage operates at both the federal and state level has been evolving in recent years. At the Federal Energy Regulatory Commission (FERC), regulatory changes have included setting new rules on how ancillary services are priced that account for the capabilities of energy storage to provide this service, and including energy storage devices in *pro forma* Small Generator Interconnection Procedures, which will help ensure the cost and time associated with interconnecting them to the grid are just and reasonable.⁶ FERC has also addressed the question of whether and when electricity storage assets can be treated for regulatory purposes as a component of the regulated transmission system (rather than part of the deregulated wholesale market).⁷ These changes are in part intended to support the development of storage technologies and recognize the uniquely valuable storage capabilities compared to conventional generation technologies.

Under Texas's current regulatory framework, if an electricity storage asset intends "to be used to sell energy or ancillary services at wholesale" it is considered to be a generation asset. Therefore, it cannot currently be owned by a TDSP if any of the value in the energy and ancillary services market should be captured.⁸ This PUCT rule is a barrier to storage deployment in ERCOT because it limits the amount of value that can be derived from storage to being either just a generation asset or just a T&D asset, but not both.⁹ In this report, we evaluate the impact that this functional separation has on the value for storage deployed on Texas's grid and compare it to a case where the full value of storage can be realized by combining the wholesale market value and the transmission, distribution, and customer reliability values.

⁶ See FERC Orders 755 and 784.

⁷ For example, in 2011 FERC encouraged system operators to modify their ancillary services markets to allow for participation of fast-responding storage devices (FERC Order 755). The Commission also approved the inclusion of storage devices into the transmission ratebase if the primary purpose of the devices was to support the transmission system, and the market revenues associated with the devices dispatch were credited back to transmission customers (130 FERC ¶ 61,056). In a separate ruling, FERC ordered that a large new pumped-hydro plant could not be treated as a transmission asset (122 FERC ¶ 61,272).

⁸ See Texas Utilities Code (1999).

⁹ See Bhatnager, *et al.* (2013), p. 9.

B. TYPES OF VALUE THAT ELECTRICITY STORAGE CAN PROVIDE

Electricity storage can be deployed for a wide range of different applications to create different types of value, some of which can be additive to each other and some not. These value streams range from reducing electricity costs to end users, improving the utilization of the existing generation and T&D assets, responding quickly to changes in electricity loads and generation, and increasing customer reliability. The wide range of partially-overlapping benefits that can be provided by electricity storage devices falls into categories including:

- **Energy Market Arbitrage** is the ability for electricity storage to absorb electric energy during low priced periods and discharge to produce energy during high priced hours.
- **Providing Ancillary Services** is the ability of electricity storage to support the real-time operations of the electricity grid by charging and discharging in granular time intervals, or maintaining readiness to respond to the need of the system to maintain reliability.
- **Reducing Ancillary Services Needs** is the ability of fast-acting storage technologies to reduce the quantity of operating reserves that system operators' need to hold aside to balance loads and generation on the power system.
- **Reducing Production Costs** is the ability of storage to reduce system-wide fuel and variable operating costs by charging during periods with low-cost generation costs and discharging during periods with high generation costs.
- **Avoiding Generation Investments** is the ability for storage to reduce the need for conventional resources, such as additional generating plants or demand response resources, to meet system-wide peak load with a reserve margin.
- **Deferring of Transmission and Distribution Investments** is the ability for storage to defer T&D system investments (and reduce the wear and tear on T&D equipment) by discharging energy to reduce load on constrained transmission and distribution components.
- **Increasing Customer Reliability** is the ability of storage devices to provide backup energy to reduce the frequency and duration of power outages faced by electricity customers.
- **Increasing Power Quality** is the ability of storage devices to improve the quality of power delivered to customers, such as by injecting real or reactive power to reduce voltage drops and stabilize local system conditions.
- **Integrating Intermittent Renewable Resources** is the ability of storage to smooth out the generating pattern of intermittent resources and thereby enable the grid to accommodate more intermittent resources while maintaining system reliability and increasing the capacity value of the intermittent resources.
- **Reducing Cycling of Conventional Generation** is the ability of storage to reduce the frequency by which conventional resources need to shut down and start up to manage low-load conditions on the power grid.

- **Reducing Emissions** is the ability for storage to reduce the operation of certain fossil fuel-based generation and thereby reduce air emissions and other pollutants from power plants.
- **Reducing Line Losses** is the ability of storage devices located close to load to reduce the energy lost in transmitting power from generating resources to load by charging during off peak conditions (with low system losses) and discharging energy during on-peak periods (with high system losses).

The location of the electricity storage has implications on the type of benefits and the magnitude of the values that may be realized. Utility scale storage located on the transmission system would naturally be capable of providing energy market arbitrage and ancillary services, integrating grid-scale renewables, and deferring specific transmission investments, among others. Deploying storage throughout the distribution system may allow for capturing more value because distributed storage can potentially perform all of the functions that utility-scale storage performs, while also deferring distribution upgrades, improving distribution reliability, and reducing line losses. We focus on estimating the value of this type of distributed storage in this study. In Section III, we estimate the value of four types of benefits: energy arbitrage and associated production cost savings, providing ancillary services, reducing generation investment needs, and deferring T&D investments. We also briefly discuss other storage-related benefits for which we have not yet estimated a value.

II. Prior Analyses Estimating the Value of Electricity Storage

Several prior studies have analyzed a range of potential economic benefits associated with electricity storage. The benefits analyzed include energy arbitrage, ancillary services, avoided generation and demand-side capacity investments, T&D improvements and deferral, improving grid reliability, and integrating renewables.

A. SUMMARY OF VALUATION APPROACHES

Several of the recent studies have been prepared by Sandia National Laboratories (Sandia) as a part of the Department of Energy Storage System Program.¹⁰ Other studies, such as the recent study conducted by Southern California Edison (SCE) or the study commissioned by the California Public Utility Commission (CPUC), focus on the potential benefits of adding storage to a specific electricity system.¹¹ Most of these prior studies concluded that even with a wide range of economic benefits, the costs of electricity storage were too high compared to the then-current investment costs. In addition, though several studies identified and quantified the likely range of economic benefits associated with electricity storage, because grid-based electricity storage is not yet a cost-effective investment (except under certain limited market conditions), the studies have

¹⁰ For example, see Sandia (2010).

¹¹ For example, see Kaun and Chen (2013).

not “packaged together” all of the benefits in such a way that investors could monetize the benefits and build a robust business model at a significant scale that would yield a return commensurate with the associated costs and risks.

Almost all prior studies that examine the economic benefits of electricity storage consider that electricity storage installed on the distribution system can improve distribution reliability and defer future investments. The studies that discussed distribution-related benefits include Sandia (2009), Gyuk (2003), and SCE (2011). They explain that if installed downstream of a distribution system failure, electricity storage can avoid customer outages. Outages, whether planned or unplanned, can be avoided by discharging the battery to serve the load that would otherwise have lost power during the outage. The outage reduction benefit is then calculated by multiplying the value of lost load (VOLL) with the MWh-size of outages avoided. SCE (2011) and other studies point out that benefit estimates depend heavily on the VOLL, which varies widely across customer types.¹²

Some prior studies also explain that storage can defer large and infrequent distribution system upgrades. For example, an expensive distribution system upgrade to handle load growth, which will be needed only for a few hours of the year, can be deferred by installing a battery. By discharging at periods of peak demand, the battery is able to reduce peak load and thereby increase the capability of the existing distribution system. In a few of the studies we reviewed, the batteries are sized to defer the upgrade one or two years, with the savings from T&D deferral estimated based on the levelized cost of the T&D upgrade multiplied by the number of deferral years.¹³

While many of these studies discuss, in a general manner, that a deployment strategy should aim to maximize value (for example by deploying for energy arbitrage or T&D deferral value), almost all of them stop short of conducting a more detailed examination of where and how in the T&D systems storage can be used most effectively, considering specific system configurations and load growth patterns. One exception is a SCE (2011) study that evaluated the benefits of deploying storage at different locations on SCE’s transmission and distribution system, including near generation locations, end-user sites, and various points within the T&D system. A Sandia report (2009) describes the type of transmission and distribution costs that can be deferred when an existing transmission network is constrained to serve “load pockets” (where the load is greater than the amount of transmission needed to transfer lower-cost energy from outside of the load center) and when distribution substations are or will become overloaded due to load growth.¹⁴

Energy arbitrage is another of the primary storage values most commonly analyzed in prior studies. For example, Byrne and Silva-Monroy (2012), Denholm, *et al.* (2013) and Kinter-Meyer, *et al.* (2013) analyzed the impact of using electricity storage on wholesale markets. They

¹² See SCE (2011), p. 47.

¹³ See Sandia (2009, 2010), Energy Storage Association (2014), and EPRI (2010).

¹⁴ See Sandia (2009).

simulated the use of electricity storage in the ERCOT, CAISO, MISO, and NYISO markets by conducting wholesale market simulations and estimating the revenues that the storage operator/owner would receive from the wholesale markets by charging the storage during low-priced hours, producing energy in the high-priced hours, and providing ancillary services such as frequency regulation.

Some studies explain the differentiating factors across different storage technologies and discuss the strengths, weaknesses, and suitability of certain technologies to certain grid-based applications.¹⁵ Sandia (2010) categorizes applications into either providing power (MW) or energy (MWh). Power applications (such as providing frequency regulation) require the technologies that are able to inject and absorb large amounts of power for a short period of time (*e.g.*, flywheel storage). Energy applications (such as price arbitrage) require technologies that are able to hold and discharge large amounts of energy over a longer period of time (*e.g.*, traditionally provided by pumped-hydro storage and more recently, by compressed air storage).¹⁶

Most of the studies we reviewed do not “add up” all of the different types of potential benefits due to concerns that some of the benefits cannot be realized simultaneously. Sandia (2010) notes that, while a grid-based battery can provide both frequency regulation and electricity time shifting (energy arbitrage and T&D deferral), operational constraints will limit the extent to which both services can be provided simultaneously.¹⁷ For instance, as recognized in our study, while storage can often provide regulation while either charging or discharging, it cannot provide regulation up if it is already discharging at its maximum rate. To provide regulation up while producing energy, the storage may need to set aside some discharging capability and limit the amount of energy it can produce simultaneously. The same is true for absorbing energy and providing regulation down. By not “adding up” the values associated with electricity time shifting and frequency regulation, the authors of the Sandia report avoid overstating the benefits of electricity storage.¹⁸

Nevertheless, at least some of the individual value streams can be realized simultaneously and therefore “added up.” In that regard, some studies have noted that when storage is deployed a certain way or at a certain location, many of the benefits can be realized simultaneously. For example, the Sandia (2010) study states that using batteries to decrease peak load can simultaneously defer both T&D and generation investments.¹⁹ According to the authors of that

¹⁵ There are a variety of technologies that are classified as energy storage, including: pumped-hydro; solid state batteries which use electrochemical reactions to store energy; flow batteries where energy is stored in electrolyte solution; flywheels, which store energy as rotational energy; and compressed air storage, which uses a compressor and the compressed air is converted back to energy typically through a combustion turbine. For example see, Sandia (2010), p. 11–12 and Carnegie *et al.* (2013).

¹⁶ See Sandia (2010), p. 21–22.

¹⁷ See Sandia (2010), p. 124.

¹⁸ See Sandia (2010), p. 124.

¹⁹ See Sandia (2010).

report, by discharging during peak hours (as the storage devices would already do to maximize the value of energy arbitrage), the storage will naturally tend to help defer some T&D and generation investments.²⁰

We describe three of the most detailed and comprehensive studies by SCE (2011), Sandia (2010), and the Electric Power Research Institute (EPRI) (2010) in more detail below.

The SCE study identifies 20 operational uses for electricity storage and organizes these as “building blocks” to provide “practical applications.”²¹ Examples of these applications include: off-to-on peak intermittent energy shifting and firming; on-peak intermittent energy smoothing and shaping; ancillary services provision; black start provision; transmission infrastructure; distribution infrastructure; transportable distribution-level load mitigation; peak load shifting down-stream of distribution system; variable distributed generation integration; end-user time-of-use optimization; uninterruptable power supply; and micro grid formation.²² The SCE study also includes estimates of the benefit-to-cost ratios of each application and how much the costs of the storage must decrease and/or the values must increase to achieve benefits-to-cost ratios greater than 1.0.²³

The SCE study finds that the ability of storage to provide energy during peak times increases the system’s peak generating capability as well as providing other related benefits. Accordingly, the SCE study finds the peak serving capability as the most cost-effective application by creating multiple simultaneous value streams including energy arbitrage, smoothing of renewable output, reducing outages, and deferring T&D upgrades.²⁴ The authors of the SCE study state that the storage benefits when deployed on the T&D system can be very large, but the opportunities to take advantage of them may be limited and highly subject to individual circumstances because the T&D system upgrade costs can vary dramatically, even across different locations within a single system.²⁵

Examining a wide spectrum of the value proposition, the Sandia (2010) report is one of the most in-depth analyses of the range of benefits of energy storage. The study identifies 26 types of benefits and estimates the economic value of each. Similar to the SCE study, the Sandia (2010) report identifies which of the potential benefits may be achieved simultaneously. Specifically, they find that T&D deferral, energy time shifting (which also helps integrate intermittent renewable energy by smoothing its generation), and avoided capacity investment can be captured simultaneously. However, the report states that these benefits cannot easily be

²⁰ See Akhil, *et al.* (2013), p. 116.

²¹ See SCE (2011).

²² See SCE (2011), Figure 5.

²³ See SCE (2011), pp. 36–61.

²⁴ See SCE (2011), p. 9.

²⁵ See SCE (2011), p. 8.

combined with obtaining the full benefits of improving system reliability. As we recognize in our analysis, this is because a storage device that is fully discharged after reducing peak load conditions would no longer be able to supply customers during a transmission or distribution system outage.²⁶ As a result, storage that is used to participate in energy markets and to reduce peak loads in order to defer T&D upgrades will be able to provide only a portion of the full outage-related value.

While Sandia (2010) provides a theoretical and methodological foundation for estimating various types of benefits associated with electricity storage, the authors do not make conclusions about what costs, when compared to the magnitudes of the benefits, would yield financially-viable storage investments.

In another study conducted by EPRI (2010), the authors estimated the present values of deploying electricity storage for T&D support applications to be approximately \$500 per kWh of storage. The T&D applications analyzed by the authors included the ability for storage to simultaneously improve system reliability, provide generating capacity during peak, and support distribution systems. The same EPRI report states that if the same storage facilities can provide frequency regulation, generating capacity, and defer transmission investment, the present value of benefits would be in the range of \$1,228–2,755 per kWh.²⁷ The study also estimates some of the benefits (such as deferred transmission investment, arbitrage, and selling ancillary services) separately for an “average” system as well as in different independent system operator (ISO) regions, which gives the study more regional granularity than most others and enables reviewing where storage would be most valuable. With such high benefits estimates, it is one of the few studies to imply that energy storage could be economical at then-current capital costs. However, that EPRI study calculated these values individually and did not address the potentially associated operational issues that would likely arise by “adding up” all the benefits.

One important theme from these studies is that because there are many different beneficiaries to electricity storage deployment, it would be difficult to coordinate the stakeholders to capture the bulk of the benefits in such a way that the overall benefits would exceed the costs to yield financially viable projects. Several studies have stated that investment in electricity storage has been hindered by the inability to simultaneously involve all stakeholders to cooperate in ways that allow all storage-related benefits to be captured.²⁸ For instance, Sandia (2010) notes that storage benefits “tend to be difficult to aggregate in practice because, for example, different benefits accruing to several stakeholders must be coordinated for a given value proposition to be financially attractive and operationally viable.”²⁹ We address this specific challenge in Sections V and VI of our report.

²⁶ See Sandia (2010), p. 124.

²⁷ See EPRI (2010).

²⁸ See Hoffman, *et al.* (2010), Sandia (2010), Kaun and Chen (2013), and Akhil, *et al.* (2013).

²⁹ See Sandia (2010), p. 123.

B. ESTIMATED VALUE OF ELECTRICITY STORAGE IN PRIOR STUDIES

The estimated benefits associated with electricity storage have ranged widely across many studies, even within individual categories of benefits, as summarized in Table 1. Some studies quantified the values in terms of dollars per kW of a storage device's generating capability, similar to the method used to evaluate the financial viability of generators, while others estimate benefits on an annualized \$/kW-year or express benefits per kWh of storage.

The wide discrepancy in analytical assumptions and the resulting wide ranges of estimated value estimates make the comparison of the findings less meaningful than had the metrics been entirely consistent. Nevertheless, these study results provide helpful reference points. Estimated benefits range over an enormous span from \$5/kW of storage for providing voltage support to \$6,400 per kW of storage for deferring T&D upgrades. A smaller number of studies estimate the range of annualized benefits from \$20/kW-year to \$130/kW-year of storage. Many of these studies analyze only one type of benefit, which accounts for some of the discrepancies. Table 1 below summarizes the wide range of storage benefits estimated in various prior studies we have reviewed.

As shown in Table 1, Kaun and Chen (2013) found that the breakeven cost for energy storage ranged from \$1,000 to \$4,000 per kW of storage (with battery lives of 5, 7, and 10 years), which includes all societal benefits (not just the benefits that can be captured by the storage owners).³⁰ Sandia (2010) estimated the benefits of storage to be ranging from \$31/kW to \$3,000/kW over a ten year period.³¹ Since the authors did not explicitly combine their value estimates, they do not produce an estimate of the maximum value of storage per MW of battery as we do in this study (although they do suggest that numerous benefits might be achievable simultaneously).

Denholm, *et al.* (2013) estimated the energy and reserve values of a 100 MW storage device installed in Colorado to be approximately \$128/kW-year for a battery that could provide reserves while it was charging and \$115/kW-year if it could not.³² They also compiled a list of other studies' estimates on the value of energy storage in numerous U.S. electricity markets (none of which specifically studied ERCOT), with values ranging from \$29/kW to \$429/kW.³³ Kinter-Meyer, *et al.* (2013) estimated that the annual energy arbitrage values from storage in ERCOT range from \$101 to 116/kW-year. The authors concluded that electricity storage focused solely on arbitrage was not viable in ERCOT, given the current cost of storage.³⁴

³⁰ Note that storage benefit values are reported as they appear in the study. A few are in \$/kW and most are in \$/kW-year. See Kaun and Chen (2013), p. v.

³¹ See Sandia (2010), p. xix.

³² See Denholm, *et al.* (2013), p. 32.

³³ See Denholm, *et al.* (2013), p. 3.

³⁴ See Kinter-Meyer, *et al.* (2013), Table 8.8.

Table 1
Storage Benefits Estimated in Other Studies

Type of Benefits	Study	Value in \$/kW	Value in \$/kW-yr
Ancillary Services			
Load Following	Sandia (2010)	\$785–\$2,010	
Area Regulation	Sandia (2010)	\$600–\$1,000	
Regulation	EPRI (2010)	\$255–\$426	
Regulation	Denholm and Letendre (2007)	\$236–\$429*	
Regulation	Walawalkar, <i>et al.</i> (2007)	\$163–\$248*	
Regulation	Byrne and Silva-Monroy (2012)	\$117–\$161*	
Operating Reserves	Sandia (2010)	\$57–\$225	
Spinning Reserves	EPRI (2010)	\$80–\$220	
Contingency Reserves	Denholm and Letendre (2007)	\$66–\$149*	
Voltage Support	Sandia (2010)	\$400	
Voltage Support	EPRI (2010)	\$9–\$24	
VAR Support	EPRI (2010)	\$4–\$17	
Ancillary Services	Denholm, <i>et al.</i> (2013)		\$115–\$128
Arbitrage			
Retail Time-of-Use Energy Charges	Sandia (2010)	\$1,226	
Retail Time-of-Use Energy Charges	EPRI (2010)	\$1,508–\$3,258	
Energy Arbitrage	Sandia (2010)	\$400–\$700	
Energy Arbitrage	EPRI (2010)	\$134–\$800	
Energy Arbitrage	Sandia (2004)	\$49	
Energy Arbitrage	Kirby (2012)	\$46*	
Energy Arbitrage	Figueiredo, <i>et al.</i> (2006)	\$37–\$45*	
Energy Arbitrage	Walawalkar, <i>et al.</i> (2007)	\$29–\$240*	
Energy Arbitrage	Byrne and Silva-Monroy (2012)	\$25–\$41*	
Energy Arbitrage	Kinter-Meyer, <i>et al.</i> (2013)		\$101–\$116
Energy Arbitrage	Sioshansi, <i>et al.</i> (2009)		\$60–\$110
Energy Arbitrage	Jenkin and Weiss (2005)		\$50–\$75
Production Cost Savings	Denholm, <i>et al.</i> (2013)		\$23–\$75
Capacity			
Avoided Capacity Investment	Sandia (2010)	\$359–\$710	
Avoided Capacity Investment	EPRI (2010)	\$88–\$726	
Retail Demand Charges	EPRI (2010)	\$710–\$5,049	
Retail Demand Charges	Sandia (2010)	\$582	
Renewables			
Renewables Capacity Firming	Sandia (2010)	\$709–\$915	
Wind Integration, Short Duration	Sandia (2010)	\$500–\$1,000	
Wind Integration, Long Duration	Sandia (2010)	\$100–\$782	
Renewable Energy Integration	EPRI (2010)	\$104–\$1,866	
Renewables Energy Time-shift	Sandia (2010)	\$233–\$389	
T&D			
T&D Upgrade Deferral	EPRI (2010)	\$1,242–\$6,444	
T&D Upgrade Deferral 90 th Percentile	Sandia (2010)	\$759–\$1,079	
T&D Upgrade Deferral 50 th Percentile	Sandia (2010)	\$481–\$687	
Transmission Support	Sandia (2010)	\$192	
Transmission Congestion Relief	EPRI (2010)	\$114–\$2,208	
Transmission Congestion Relief	Sandia (2010)	\$31–\$141	
Substation On-Site Power	Sandia (2010)	\$1,800–\$3,000	
Electric Reliability and Power Quality	Sandia (2010)	\$359–\$978	
Power Reliability	EPRI (2010)	\$47–\$537	
Power Quality	EPRI (2010)	\$19–\$571	
Multiple Benefits			
Arbitrage and Contingency Reserves	Drury, <i>et al.</i> (2011)	\$38–\$180*	
Arbitrage and Regulation	Kirby (2012)	\$62–\$75*	
T&D, Capacity, Arbitrage, A/S	Kaun and Chen (2013)	\$1,000–\$4,000	

Note: *Compiled in Denholm, *et al.* (2013), Table 2-1.

III. Analytical Approach to Estimating Storage Costs and Benefits

In this section, we describe our analytical approach to estimating the costs and benefits of deploying storage throughout the ERCOT distribution systems and dispatching it into the ERCOT wholesale power markets. We show various projections of the expected reduction in storage costs—consistent with the installed cost of \$350/kWh that we use in our study—and describe our financing assumptions for translating these costs into levelized annual costs. We then describe our analytical approach to estimating the wholesale power market value streams of storage, including avoided production costs and avoided capacity investments, as well as distribution system value streams such as deferred T&D costs and avoided outages experienced by end-use electricity customers. These value streams are generally additive as we analyze them, with some types of value quantified differently, depending on the benefits perspective taken.

A. STORAGE COSTS

Historically, the costs of storage have been prohibitively high for many applications, but recent trends and current projections indicate substantial cost reductions that will make storage more economically attractive in the near future. As illustrated in Figure 2, current projections indicate that lithium-ion battery costs will decline from the current \$700–\$3,000 per kWh of installed electricity storage in 2014 to less than half of that over the next three years.^{35,36} Two other projections, from Morgan Stanley and UBS analysts, point to even more significant cost reductions, forecasting battery-only costs of \$125–\$150/kWh in the near future, which would likely correspond to total installed costs of somewhat below \$350/kWh by 2020.³⁷

A primary driver of declining costs is the large scale and technological improvements expected with electric vehicle (EV) development and deployment, particularly by Tesla Motors. Tesla is currently constructing a “Gigafactory,” which will have the capacity to manufacture 35 GWh of

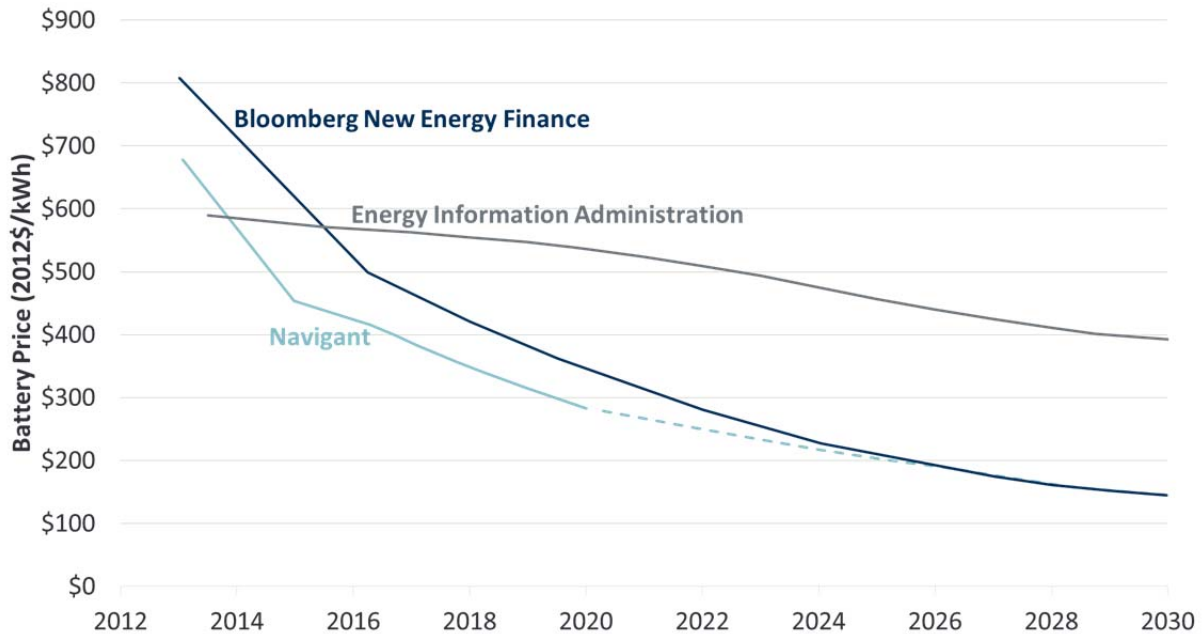
³⁵ Many storage developers quote costs on a per kWh or MWh basis. This represents the capital cost in terms of how much energy it can store, as opposed to the maximum instantaneous power output that would be quoted in kW terms. For example, a 300 kWh device at \$350/kWh would have a capital cost of \$105,000. The capacity that it can output instantaneously depends on the energy to power (or kWh:kW) ratio of the device, which we assume to be 3:1 in our study. That means, the 300 kWh device would be capable of outputting a maximum of 100 kW for three hours continuously.

³⁶ Navigant notes that current storage costs for a four-hour battery are \$720–\$2,800/kWh depending on the scale of the battery. According to Sam Jaffe of Navigant Research, battery-only costs are currently around \$500–700/kWh with the remaining installation costs due to system costs. Also see Dumoulin-Smith, *et al.* (2014a), p. 1.

³⁷ The \$350/kWh projection of the installed cost of a battery system is based on Oncor’s discussions with vendors, consistent with industry sources. For example, Morgan Stanley and UBS predict that battery-only costs may reach \$125–\$150/kWh in the near future, down from the \$500/kWh currently, see Byrd, *et al.* (2014), p. 40, and Dumoulin-Smith, *et al.* (2014a). See also Jaffe (2014), p. 30.

batteries each year starting in 2020. This is more than the entire world-wide production of lithium-ion batteries in recent years.³⁸

Figure 2
Lithium Ion Installed Battery Cost Projections



Sources and Notes:

Projections are based on a learning curve for lithium-ion batteries derived from historical and projected consumer electric vehicle production. Dashed lines indicate a lower level of confidence by the original source. Reproduced from Rocky Mountain Institute (2014), Figure 19.

In our analyses, we use two benchmarks for the installed costs of grid-integrated storage in 2020. Our primary benchmark cost is \$350 per kWh of storage, consistent with vendor quotes received by Oncor and other industry projections for the year 2020. We also compare benefits to a higher benchmark cost of \$500/kWh, presuming the projected cost reductions do not fully materialize. While we have not independently studied whether these projected storage costs are achievable by 2020, these are consistent with the industry projections shown above. We also have not independently analyzed the extent to which the storage’s charge and discharge cycles necessary to obtain the benefits we estimate are achievable by the available storage technologies at the assumed costs. More precise estimates of the installed costs and operational characteristics of specific technologies and associated equipment would be needed before deployment plans could be developed.

We annualize the investment costs using the financial assumptions summarized in Table 2. These annualized costs can then be compared to the expected annual benefits. We apply this annualization on a “level-real” basis, reflecting a trajectory of annual costs that increase with

³⁸ See Dumoulin-Smith, *et al.* (2014a) and N.V. (2014).

inflation. This level-real annualization approach allows us to compare a single year's capital costs (2020) against a single year's benefits (2020) in a way that is proportionally-equivalent to comparing the net present value (NPV) of costs and benefits over the life of the battery asset, assuming that annual benefits increase with inflation.

We annualize costs in two different ways: (1) levelization is based on an 8.0% after-tax weighted-average cost of capital (ATWACC) and a 15-year asset life, consistent with the cost of capital of a merchant generation investment;³⁹ and (2) a second levelization reflects annualized investment costs using a regulated TDSP's 6.3% ATWACC, assuming a 15-year battery life and a 30-year life for the balance-of-plant components.⁴⁰

Table 2
Financial Assumptions and Levelized Cost of Storage for 2020

		Merchant	Utility
Benchmark Battery Costs			
Installed Costs	(\$/kWh)	\$350	\$350
Fixed O&M	(% of Installed)	1%	1%
Higher Battery Costs			
Installed Costs	(\$/kWh)	\$500	\$500
Fixed O&M	(% of Installed)	2%	2%
Financial and Technical Parameters			
Energy to Power Ratio	(kWh:kW)	3:1	3:1
After-Tax Weighted Average Cost of Capital	(%)	8.0%	6.3%
Battery Asset Life	(yrs)	15	15
Balance of Plant Asset Life	(yrs)	15	30
First Year Capital Carrying Cost Rate	(% of Installed)	13.1%	10.0%
Levelized Fixed Costs			
Benchmark Costs	(\$/kW-yr)	\$139	\$106
<i>Higher Costs</i>	<i>(\$/kW-yr)</i>	<i>\$200</i>	<i>\$160</i>

Sources and Notes:

Battery costs and characteristic assumptions were provided by Oncor, as were the financing assumptions relevant for a regulated utility. First year carrying cost rates are reported only for the benchmark \$350/kWh battery costs. The merchant ATWACC of 8.0% is from Newell, *et al.* (2014a).

³⁹ The 8.0% ATWACC reflects the estimated cost of capital of merchant generation investments as reported in Newell, *et al.* (2014a).

⁴⁰ This levelization includes the cost of replacing worn-out battery cells during the 15-year period. Financial parameters and ATWACC are consistent with Oncor's revenue requirement structure under which annual cost recovery declines over time, but are converted into an NPV-equivalent level-real cost recovery in which payments increase with inflation.

B. WHOLESALE POWER MARKET VALUES OF STORAGE

We discuss the various business models for electricity storage in Texas and the regulatory framework necessary to enable those business models in Section VI. For the purpose of evaluating and aggregating the values of storage, we assume that grid-integrated storage assets are allowed to be dispatched into the wholesale ERCOT energy and ancillary services markets. We simulate the storage assets' participation in these wholesale markets under 2020 market conditions and under varying levels of storage penetration. We then estimate the impact of adding storage on wholesale prices, customer costs, storage asset operating margins, investments in new conventional generation, and system-wide production costs.

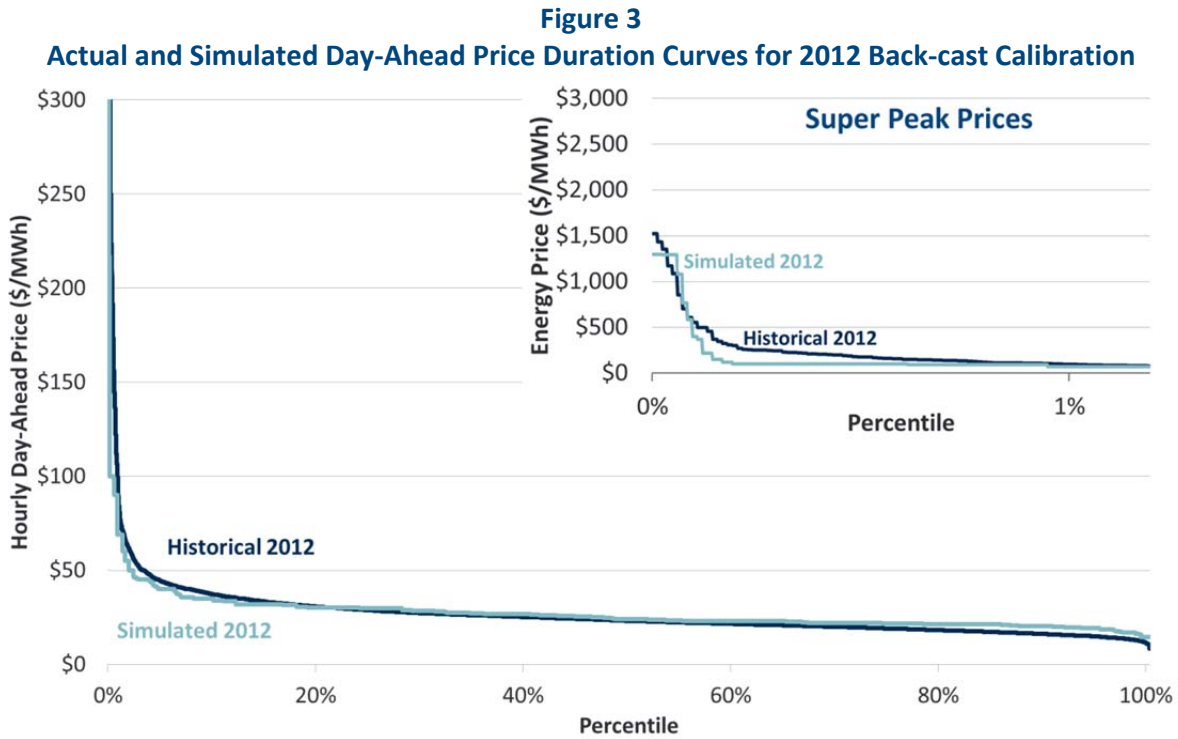
1. Overview of ERCOT Energy-Only Market Modeling Approach

As the basis for estimating each of the value streams stemming from storage participation in the wholesale power markets, we conduct market simulations to estimate how storage would participate in the market and how it would impact the market and market participants.⁴¹ We conduct this simulation using the Polaris Systems Optimization (PSO) model. Key inputs and simulation parameters include fuel prices, ERCOT's scarcity pricing mechanisms, ERCOT generation mix, and load shapes reflecting a range of weather conditions. We first simulated a historical year (2012) to calibrate the model and then simulated 2020 under equilibrium market conditions for different levels of storage deployment as discussed further below.⁴² We use ERCOT's 2014 load forecast and Capacity Demand and Reserves (CDR) report to project future load and supply mix changes respectively, while adjusting supply appropriately to reflect equilibrium conditions.⁴³ Figure 3 compares the price duration curves that we realized in our historical calibrated simulation analysis, to actual day-ahead market prices in 2012, showing a relatively accurate reflection of prices across high, moderate, and low price hours.

⁴¹ We conduct an hourly simulation model consistent with ERCOT's day-ahead wholesale market. We do not attempt to estimate the potentially higher value that might be realized if storage were able to capture additional value from the shorter-term price fluctuations and uncertainties in the ERCOT real-time market. Our hourly market simulations also consider the ability of electricity storage to provide ancillary services.

⁴² Monthly fuel prices are expressed as a basis above Powder River Basin and Houston Ship Channel forward curves for 2020 pulled as of July 30, 2014 (plus historical basis differentials escalated with inflation). The annual average delivered fuel prices we implemented are \$2.54/mmBtu for sub-bituminous coal, \$2.77/mmBtu for bituminous coal, and \$5.60/mmBtu for natural gas. Prices are based on data from Bloomberg and Ventyx, see ERCOT (2014c) and Newell, *et al.* (2014b).

⁴³ For load forecast data see ERCOT (2014b). For CDR see ERCOT (2014c).



Sources and Notes:

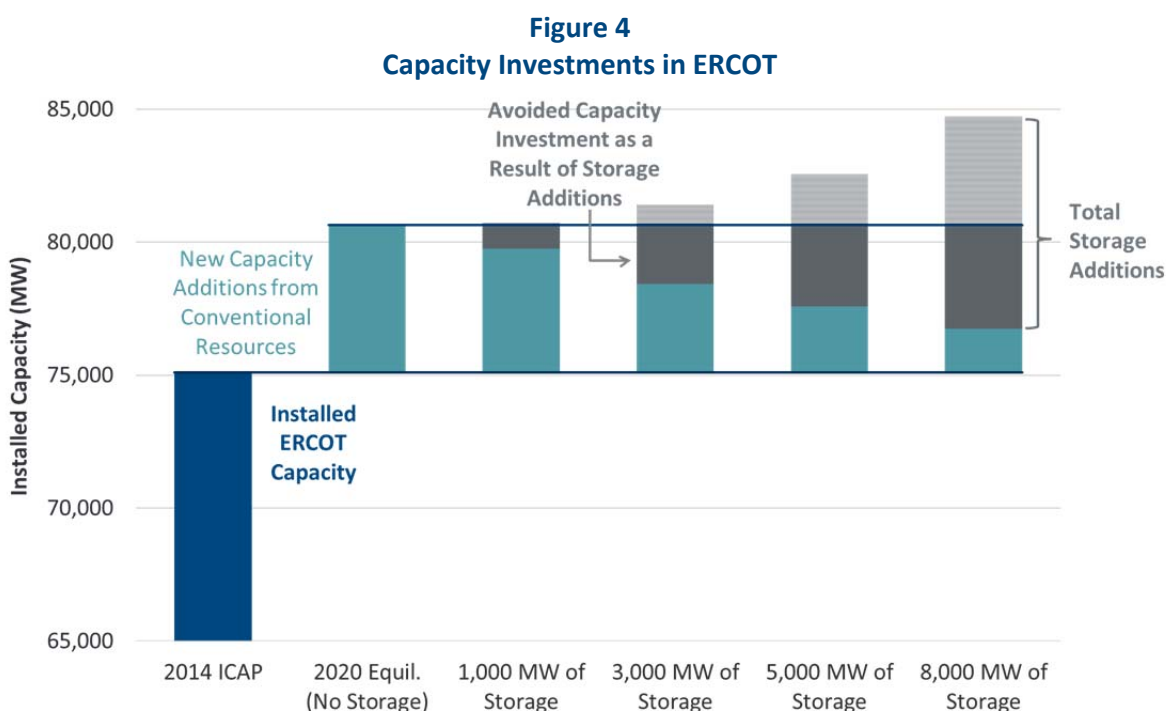
Historical prices are from the North Hub, from Ventyx (2014).

We calculate the expected average system costs and wholesale energy and ancillary-service revenues in 2020 as a weighted average of the simulated results using 2012 and 2011 weather conditions, with 2012 weather assumed to reflect a normal weather year and 2011 to reflect an extreme weather year.⁴⁴ The simulations reflect equilibrium conditions in ERCOT’s energy-only market at each level of storage deployment analyzed that takes into account how investment in conventional generation would likely respond to the deployment of storage in the ERCOT market. Specifically, we account for the effects of adding storage to the system that triggers a supply-side response, reducing the amount of generating plant additions such that the combined amount of generation and storage investments yields market prices sufficient to continue to support investment in necessary conventional generation assets. Under these equilibrium market conditions, a new natural-gas-fired, combined-cycle (CC) plant will fully recover its investment and operating costs in ERCOT’s energy and ancillary services markets. The investment and fixed

⁴⁴ Weather years are given 70% and 30% weightings for the normal and extreme weather years respectively, with the extreme weather year weight selected such that “average” customer costs, production costs, and CC energy margins would be 108%, 101%, and 119% respectively above “median” or “normal” year values. These ratios were calibrated to be approximately consistent with the ratio between average and median as obtained from our prior study that examined many weather years and also considered the year-to-year variations in reserve margins expected in an energy-only market. See Newell, *et al.* (2014b).

operating costs of a new CC plant are estimated to be equal to a levelized cost of new entry (CONE) of \$149/kW-year.⁴⁵

Figure 4 below shows our estimate of the total installed ERCOT generating capacity at different levels of storage deployment. The chart shows that in the 2020 Base Case scenario (without any storage), 5,500 MW of net generation additions will be needed between 2014 and 2020 to meet 2020 peak loads (with additional generation additions needed to replace any potential retirements). The chart also shows the estimated levels of generation investment under different levels of storage deployment. At these generation investment levels, ERCOT market prices would remain at a level sufficient to fully support cost recovery of the necessary generation additions. As also shown, each MW of storage displaces less than one MW of conventional generation.



Sources and Notes:

Year 2014 installed capacity from ERCOT (2014c). Capacity additions from new conventional generation report the net additions that we estimate would be added into the ERCOT market under our simulation modeling for the year 2020. Under the no-storage case we estimate 5,500 net additions would be needed (or 6,300 MW of gross additions once considering the more than 800 MW of retirements reported in the CDR, which are not explicitly shown in the chart. Actual retirements may significantly exceed the 800 MW already reported in the CDR)

Deploying 1,000 MW of storage in ERCOT would displace approximately 900 MW of conventional generation; deploying 5,000 MW of storage would reduce new generation

⁴⁵ Our study assumptions are adapted from a CONE study for PJM with necessary adjustments for ERCOT, see Newell, *et al.* (2012) and Spees, *et al.* (2011). Updated estimates apply escalation rates derived from Newell, *et al.* (2013).

investment needs by approximately 3,100 MW. This means that at the 5,000 MW storage deployment level, 2,400 MW of generation investments would be needed just to meet load growth. Additional new generation would be required to replace retirements, which are not reflected in the chart. The 2014 ERCOT CDR projects an additional 840 MW of retirements by 2020, while the ERCOT Long-Term System Assessment projects 7,600 MW of coal and gas steam retirements by 2029 in its Base Case scenario or upwards of 20,000 MW of total retirements in its 2029 stringent environmental scenario.⁴⁶

It is important to note that in both cases, with and without storage, new generation investment will be forthcoming only if the operating margins earned in ERCOT's energy and ancillary services markets are sufficient to support the investment. Our simulations show that, once we account for investment response (*e.g.*, recognizing that 3,100 MW of less new generation would be built in response to deploying 5,000 MW of storage), the remaining generation investments and the existing generation will be equally profitable with or without storage deployment. If that were not the case, market participants would respond by further reducing generation investment until such equilibrium is approximately reached. From a societal perspective, the avoided capital investments from conventional capacity additions represent a category of benefit that offsets the total societal costs of adding storage, with the avoided capacity investments valued at \$149/kW-year.

Our analysis shows that, even at the 8,000 MW storage deployment level examined in our study, approximately 1,600 MW of new generation investment would still be necessary by 2020 to reach equilibrium market conditions. The ERCOT energy-only market supports new generation investment through prices sufficient to recover the investment costs, including an adequate return on the investment. This means that even a very large deployment of storage is not likely to create excess supply conditions that would suppress market prices below equilibrium levels, with related adverse consequences for existing generation suppliers. This is particularly true if the deployment plans are publicly available and the anticipated gradual increase in storage investments can be anticipated by generation investors. The share of traditional generation investment need that would actually be displaced by storage may be even less than we have estimated, because storage will be deployed gradually and the TDSPs will require many years—likely beyond 2020—before reaching multiple thousands of MWs of storage investments.

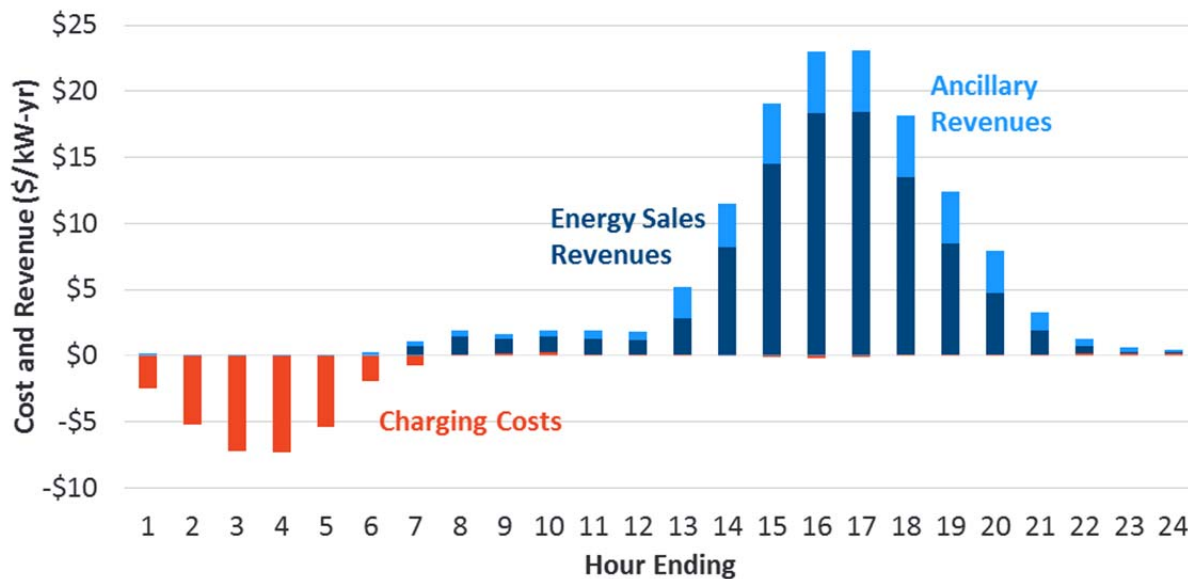
2. Storage Dispatch into Energy and Ancillary Markets

We simulate the storage assets' participation in the ERCOT wholesale market similarly to other resources. Like with other generators, the PSO model optimally dispatches the storage to charge, discharge, and provide ancillary services in a way that minimizes system-wide production costs. Based on that market-dispatch-based schedule and the realized market prices for energy and ancillary services, we determine the storage assets' realized market-based costs and revenues.

⁴⁶ See ERCOT (2014c) and ERCOT (2014e).

The annual costs incurred and revenues obtained by hours of the day (on average) are summarized in Figure 5. Of course, the actual charging and discharging patterns differ across days and seasons. For example, during the winter the storage may charge-discharge two cycles per day in response to distinct morning and evening peaks.

Figure 5
Storage Charging Costs and Revenues for Providing Energy Arbitrage and Ancillary Services
 (Average Annual Values Based on 5,000 MW Storage Deployment)



Notes:

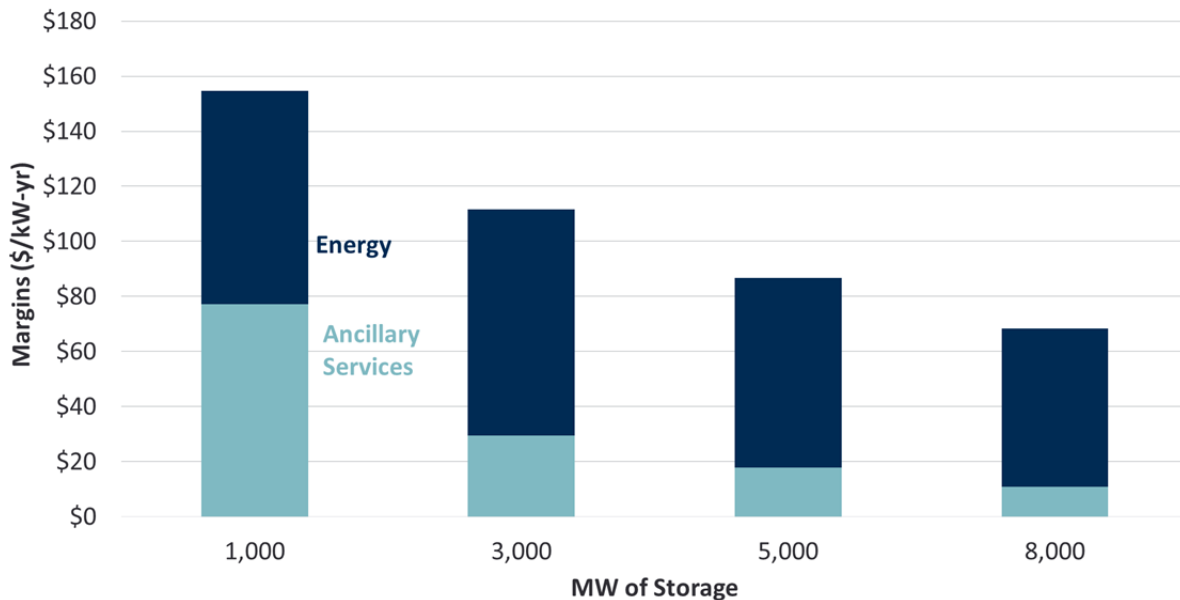
Ancillary Services Revenues include regulation, responsive, and non-spinning reserves. The small amount of charging during the day and discharging at night primarily occurs in the winter months. The small amount of positive charging “revenues” during a few hours are a result of charging in hours where the price is negative (and therefore the storage receives revenues to charge, instead of paying for the energy charged).

The hourly energy-arbitrage values obtained by the storage follow daily pricing patterns. Energy prices vary significantly throughout the day and across days. Storage is able to take advantage of these price variations by storing low cost energy during off-peak hours and then discharging the stored energy when the prices are higher. While these energy arbitrage values can be quite substantial, they are limited by the storage’s technical constraints, including the 15% round-trip efficiency loss associated with the charge-discharge cycle, the capacity rating which is determined by the maximum instantaneous discharge capability, and the maximum energy rating. We assume that the maximum energy and power ratings to be consistent with a three-hour discharge at maximum capacity. The storage assets are also regularly scheduled to sell ancillary services, but can only sell a combination of energy plus ancillaries up to the maximum capacity rating and provide most ancillary services only if the devices are charged.

Figure 6 summarizes the total annual net revenues per kW of storage that the device would obtain in the ERCOT wholesale markets at different storage deployment levels. The chart shows that participation in the ancillary services market would provide approximately half of the total value at a 1,000 MW storage deployment level, with the other half coming from energy market arbitrage. The flexibility and fast response times of storage make it a natural fit to provide

ancillary services, which leads to relatively large ancillary services revenues. With their ability to switch from charging to discharging almost instantaneously, batteries can provide regulating (or frequency) reserves quite effectively.

Figure 6
Annual Net Revenues per kW of Storage (2020)



As shown in Figure 6, the portion of net revenues from ancillary services declines at higher storage deployment levels due to the limited size of the ancillary services markets. Overall, ERCOT requires only 400–500 MW of regulation up and down service, 2,800 MW of responsive reserves, and 1,500 MW of non-spinning reserves, although the realized contingency reserve quantities will differ and will affect the contingency reserve pricing as a function of the Operating Reserve Demand Curve (ORDC).⁴⁷ The limited market size, and that there are other relatively low cost ancillary services providers, results in the decline of the relative size of ancillary services revenues per kW of storage at battery deployment levels beyond 1,000 MW.

Net energy revenues earned by the storage asset also decline at higher storage deployment levels, although not as rapidly as ancillary services revenues. This decline is because storage has the

⁴⁷ We implement the ORDC in the hourly day-ahead simulations. Although ERCOT only implements the ORDC in its real-time market, we implemented it on a day-ahead basis reflecting that market participants will incorporate their expectations about real-time market conditions into their day-ahead market participation. For a more comprehensive description of ORDC, see Newell, *et al.* (2014b), Section II.F.5; and ERCOT and Hogan (2013). For a summary of ERCOT’s ancillary service requirements see Potomac Economics (2014), p. 31. We do not incorporate any of the ancillary market revisions that might be adopted as a result of ERCOT’s future of ancillary services proposal, see ERCOT (2014d).

effect of reducing peak prices and increasing off-peak prices, such that increasing deployment reduces the arbitrage opportunities.

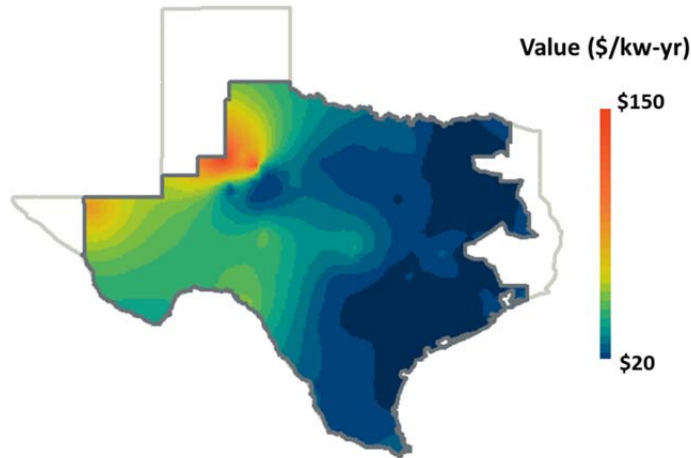
Our analysis of storage merchant value in the ERCOT day-ahead energy and ancillary services markets is based on a zonal representation of the market.⁴⁸ Our analysis does not yet capture the additional value that can be obtained by participating in the more volatile real-time market or deploying in targeted locations where arbitrage values may be higher. Because price changes in the five-minute real time market tend to exhibit more volatility, storage would be able to capture an additional arbitrage value in the more volatile but short-lived real-time pricing events. However, the additional charge and discharge cycles of real-time operations may negatively impact the lifespan of the batteries, a factor that we have not yet analyzed.

Higher merchant values might be achieved by targeting storage deployments to locations with greater arbitrage opportunities. Figure 7 below shows locational arbitrage values of storage devices based on actual 2012 real-time market prices. This diagram provides an indication of the range of locational differences in arbitrage values that could be realized within the ERCOT market. At the relatively low market prices that existed in 2012, many locations in ERCOT would have yielded only \$20–50/kW in annual arbitrage revenues. In some export-constrained regions of western Texas, however, annual revenues from arbitrage value could have been as high as \$150/kW-year. These highest-value locations in west Texas experienced very low or sometimes negative prices during a portion of the day due to high levels of wind generation and transmission constraints that prevented the export of that generation to the rest of ERCOT. However, these congestion patterns have been mitigated as major new transmission lines interconnecting western Texas with the load centers in the east were placed into service during 2013.⁴⁹ As additional renewable generation is added to the system, similar congestion patterns may reemerge over time and thereby increase the arbitrage value at certain locations.

⁴⁸ We model twelve different zones with generation and load mapped into each zone, consistent with ERCOT weather zones and major cities.

⁴⁹ The effects of these transmission upgrades are reflected in our modeling, which represents the system in year 2020.

Figure 7
Illustrative Example of Locational Price Arbitrage Value based on 2012 Market Prices



Note:

Reflects a price-taking dispatch simulation against historical 2012 hourly, real-time nodal prices. Results represent a battery charging in the three lowest price hours and discharging in the three highest priced hours per day.

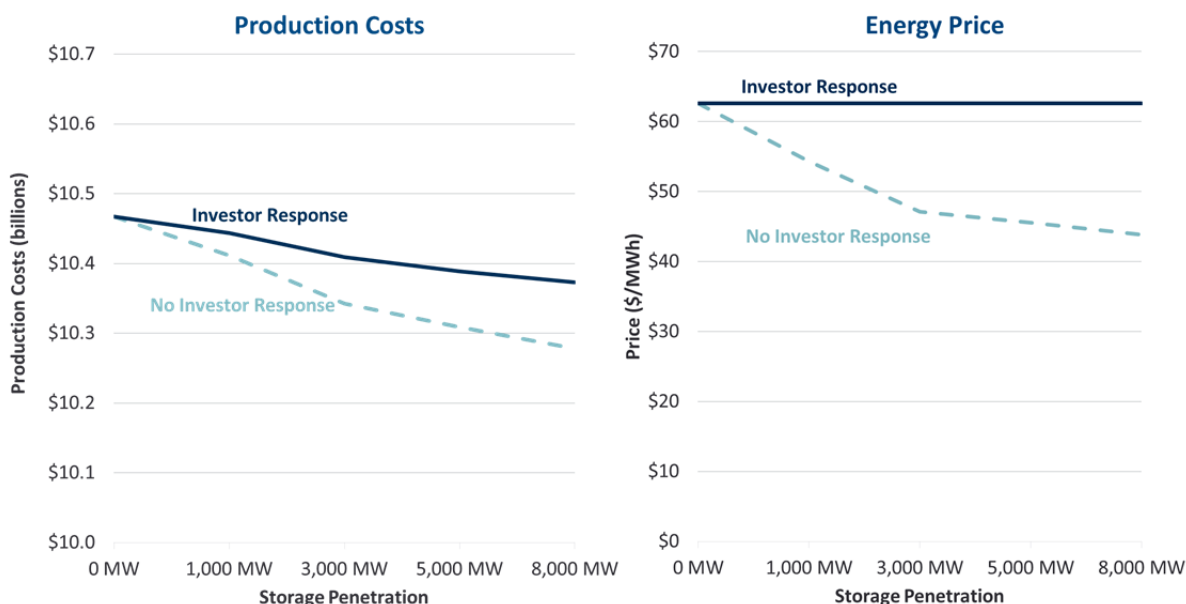
3. Market Price and Production Cost Impacts

Integrating a substantial amount of storage into the wholesale power markets can have a strong impact on system-wide costs and market prices. Our simulation-based estimates of these impacts are shown in Figure 8 below. The left chart in Figure 8 shows system-wide production cost for the different levels of storage deployment, while the chart on the right shows load-weighted average market prices.

From a system-wide or societal perspective, production cost savings are the relevant metric for measuring the benefits of storage in terms of its impact on fuel costs, variable operations and maintenance (O&M) costs, and demand response deployment costs. Storage will reduce some of these costs by reducing the dispatch of high-cost peaking resources and increasing the dispatch of lower-cost baseload resources. Our estimate of total production costs is shown as a solid line in the left chart of Figure 8.

Figure 8

Production Costs and Load-Weighted Energy Prices and vs. Storage Penetration Level



Notes:

“No Investor Response” results reflect a simulation in which storage is added to the system without implementing any offsetting decrease in traditional generation supply, thereby pushing the system into an excess supply condition.

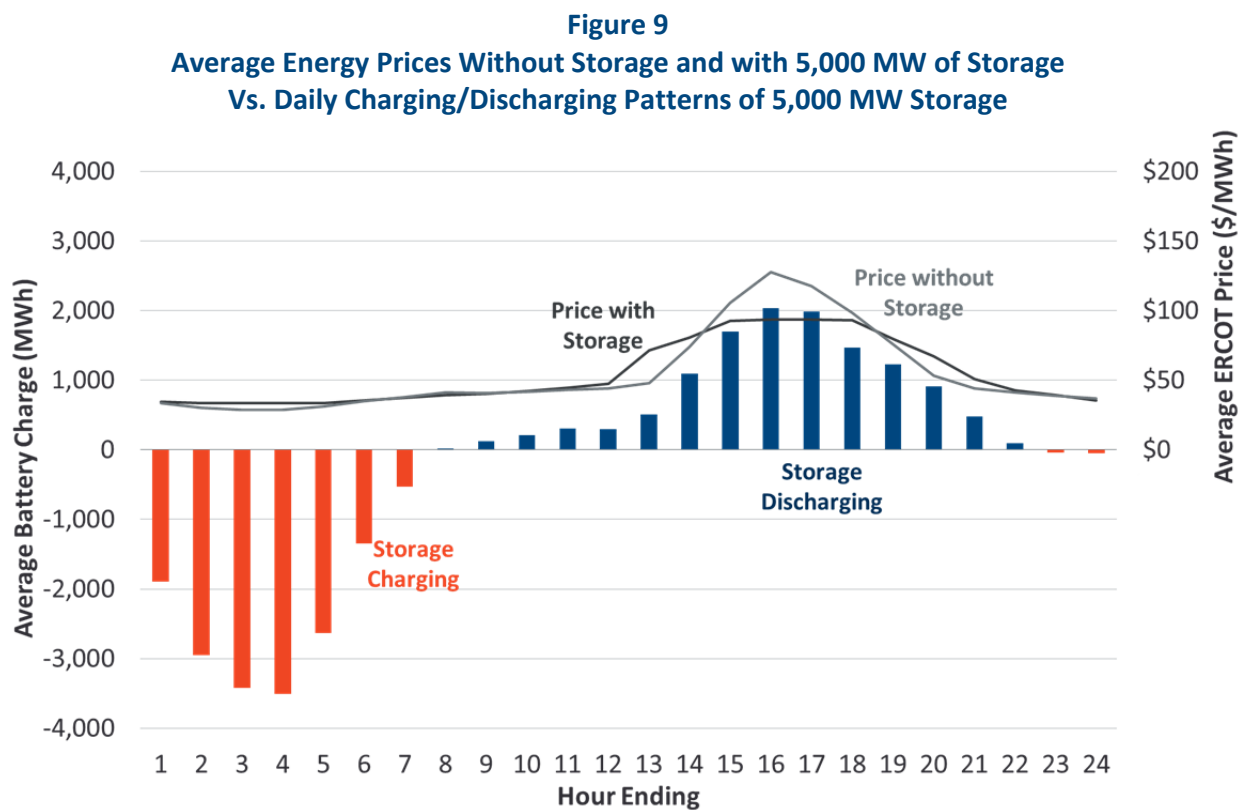
“Investor response” results reflect those that we have used for our study, and account for the reduction in traditional generation investments that would be expected, such that prices would be restored to equilibrium levels.

The deployment of storage facilitates results in a substantial amount of load shifting, which would result in significant production cost savings if one were to assume that investment in conventional generation would be entirely unaffected by storage additions. Such a result, however, is quite unrealistic and would significantly overstate achievable production cost savings by failing to account for generation investment response. The lower peak loads and peak prices would certainly be anticipated and reduce the need and market incentives for conventional generation investment. Because of reduced future generation investments, prices will remain sufficiently high to support the remaining generation investment. Thus, the net impact on production costs is much more modest than in static studies that do not consider generation investment response. The dashed line shown in the left chart of Figure 8 shows the substantially higher production cost savings that we would have estimated without accounting for this investment response. Because our analysis accounts for the impacts of reduced generation investment that will occur in response to storage deployment, we estimate a modest level of production cost savings compared to other similar studies.

The impact on wholesale market prices is the most important metric from the perspective of market participants, including both customers, merchant storage investors, and other generators. Customers can benefit from such price impacts because the use of storage can reduce power purchase costs by reducing power prices during system peaks—although these savings are partly offset by increased prices during off-peak periods. However, as shown in the right chart of Figure 8, after considering generation investment response, average market prices change very little and power purchase cost savings are quite small across a wide range of storage deployment

levels. Again, for illustrative purposes, we show a dashed line representing the much greater price impact that we would have estimated without accounting for generation investment response. By accounting for the impact of generation investment response, our simulation results reflect a more realistic market outcome in which market prices continue to be at a high enough level to fully support investment in necessary additional generation resources.

Figure 9 below summarizes average market prices and storage charging and discharging patterns over the course of a day. The grey solid lines in Figure 9 show hourly market prices over the course of a sample average day in an ERCOT system without storage and a system with 5,000 MW of storage. As expected, charging during the off peak hours slightly increases prices, while discharging during the on peak period lowers peak prices. Interestingly, however, the reduction in peak prices broadens and flattens the peak pricing profile; while peak prices are lower, they are realized during more hours of the day, resulting in almost the same price on average over the course of a day.



Notes:

This graph reflects hourly average schedules and prices in each hour of day, averaged across the year.

4. Impacts on Other Generation Suppliers

One important consideration when adding a substantial quantity of storage to the power system is the impact those additions might have on other generation suppliers. This is of particular concern to ERCOT’s energy-only market and its ability to maintain sufficient incentives to attract necessary investments in conventional generating resources. Existing generation suppliers will have an interest in whether storage additions will materially affect the value of

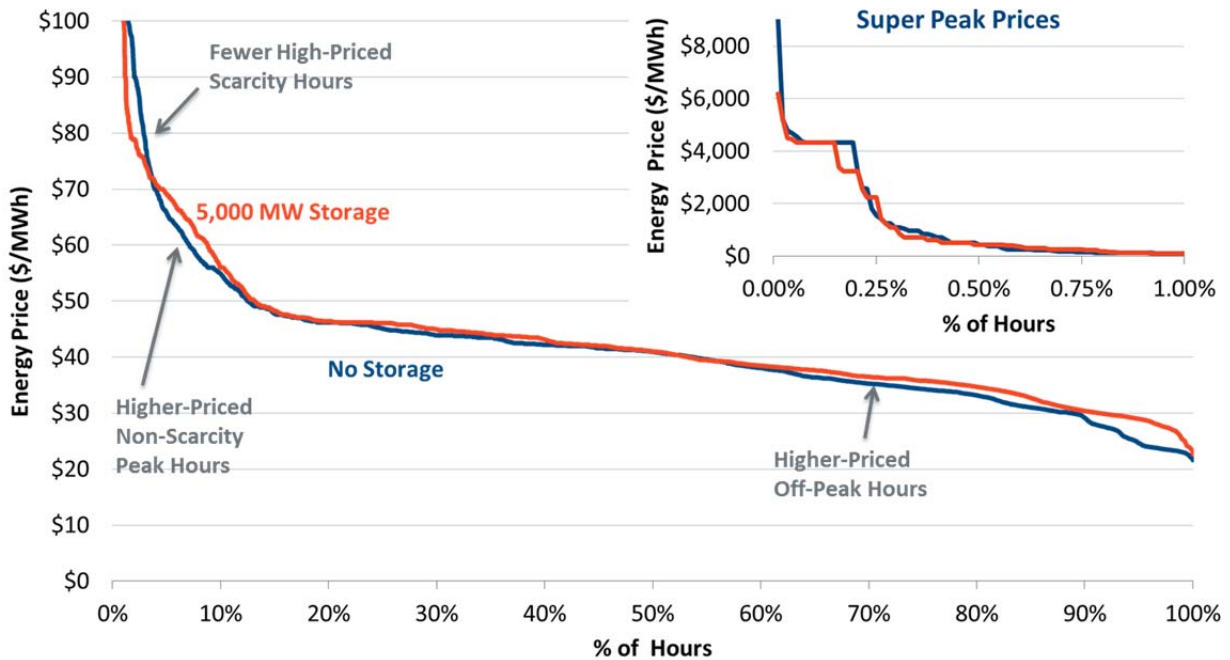
their assets. From a public policy perspective, it is important to ensure that developing storage will not inefficiently distort energy markets, undermine investment incentives, or create regulatory uncertainties.

The primary worry, for both policy-makers and generation suppliers, might be that adding a large quantity of storage could create excess supply that would artificially suppress market prices. While we share these concerns, our analysis shows that a substantial quantity of storage can be developed in ERCOT without creating these problems and introducing such distortions. This would require storage additions to be anticipated by market participants and phased in over a sufficiently long period such that these additions will not fully replace the need for new generation capacity. Doing so will avoid excess supply conditions in which prices would be suppressed below the levels needed to attract new generation investments.

As we explained in Section III.B.1, even deploying 8,000 MW of storage in ERCOT by 2020 would not displace all of the necessary new generation additions. A deployment level of 3,000 to 5,000 MW would represent even less risk. While some developers of new generating plants would be unable to proceed with the development of their projects during this time period, prices would nevertheless need to remain high enough to attract the necessary generation resources. Therefore, the net revenues for efficient existing and new generating plants would remain approximately the same with and without storage.

Despite the net revenues of efficient new and existing generating plants remaining approximately the same once generation investment response is taken into consideration, adding storage to the ERCOT system would change the profile over which these revenues are earned. This impact is shown in Figure 10 and Figure 11 below for deploying 5,000 MW of storage on the ERCOT system. The first chart shows the differences in price duration curves over the year for our market simulations with and without storage. Similar to the results presented above, this price duration curve shows that off-peak and non-scarcity on-peak prices would increase, while frequency and magnitude of extreme scarcity prices would decline. Generation suppliers would benefit from a slight increase in price stability, while enjoying very similar average prices and anticipated operating margins in aggregate across the year.

Figure 10
2020 Price Duration Curve Without Storage and With 5,000 MW of Storage

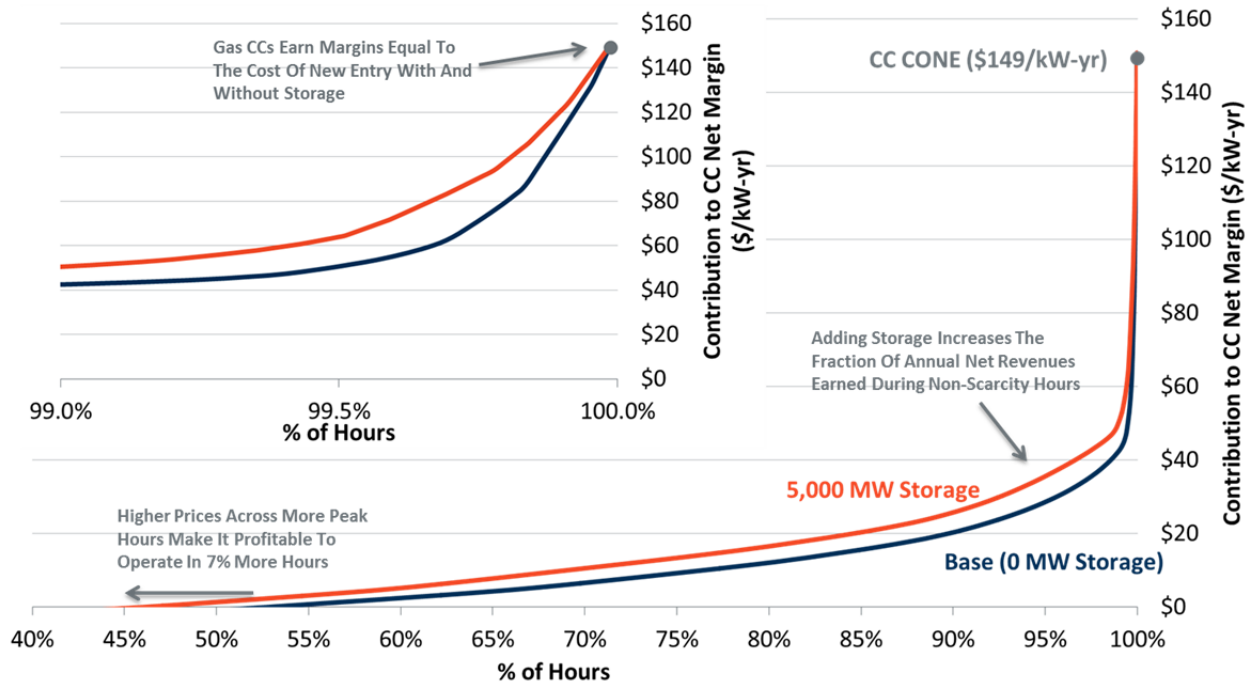


Notes:

Prices sorted from highest price (on the left) to lowest price (on the right) over all simulated hours of the year.

Figure 11 below shows the cumulative operating margins for a natural-gas-fired, combined-cycle plant. Operating margins are zero for the lowest 50% of hours of a year, reflecting the fact that a gas CC will operate profitably only during approximately half of all hours. Then cumulative operating margins increase as more profitable hours are added until total annual margins reach the annualized investment and fixed operating cost of the plant, which we estimated as \$149/kW-year. This cumulative value is the same with or without storage but, as shown, energy margins will be earned during a larger number of hours of the year, which will make investment cost recovery less dependent on the small number of extremely high-priced hours.

Figure 11
2020 Cumulative Gas CC Margins Without Storage and With 5,000 MW of Storage



Notes:

Chart shows cumulative net revenue accrued over the year summing from the lowest net revenue hours (on the left) to the highest net revenue hours (on the right).

C. TRANSMISSION AND DISTRIBUTION SYSTEM BENEFITS

The deployment of storage on a distributed and grid-integrated basis would allow the TDSPs to deploy storage in locations where storage can defer the need for some T&D investments and provide reliability benefits to electricity users. The T&D utilities are uniquely well-positioned to determine the best locations for deploying storage on the distribution grid as a part of their integrated distribution and transmission planning processes. TDSPs can also focus deployment of electricity storage to the most beneficial distribution system locations, such as at feeders with poor reliability where storage can substantially reduce the frequency and duration of retail power outages. A TDSP would be able to locate the electricity storage on its distribution system’s right-of-way, where the devices are easily accessible and where they can be deployed and maintained in concert with the utility’s other distribution equipment.

This section of our report focuses on estimating two distinct benefits related to grid-integrated deployment of storage: (1) the benefit of deferring traditional transmission and distribution system investments; and (2) the reliability benefit of reducing the frequency and duration of distribution-system-related retail customer outages.

These T&D-related benefits are additive to the wholesale market values of storage discussed in the prior section for two reasons. First, price-driven energy sales that reduce distribution system peak loads will also reduce the peak loads on the supporting T&D system, thereby reducing T&D investment needs. Second, distribution outages are infrequent and the outages rarely occur

during peak-load periods, and therefore reducing distribution outages would not typically affect T&D investments that are driven by peak load. However, to be certain that we are not too aggressive in assuming no overlap between the two types of benefits, we heavily discount our estimate of theoretically-achievable reliability value (if the TDSP had perfect foresight of the time and locations of all outages) to account for times when the storage devices may already be discharged or when a distribution outage may occur downstream from the storage location.

1. Deferred Transmission and Distribution Investments

As we discussed in our review of prior studies, deploying grid-integrated storage devices can help defer T&D investments. Because storage can be discharged during high-price periods that typically correspond to peak load conditions, the storage will reduce the net load that the T&D system must support. Since we contemplate a distributed deployment of storage, the injection of energy from storage would be co-located with end-user loads on the distribution system. The net load that distribution substations and major transmission facilities would need to support would then be the end-user load minus the energy injections from storage.⁵⁰ Consequently, the peak-shaving impact of storage will reduce the pace and magnitude of the T&D investments that otherwise would need to be made to meet growing system loads. We describe our approach to estimating the magnitude of these investment deferrals first in the transmission system, and then in the distribution system.

Deferred Transmission Investments. Storage can defer transmission system upgrades by reducing peak load net of storage's energy discharge. Electricity storage also may defer some necessary transmission investments by providing reactive power, voltage support, and by injecting energy into the transmission system on a temporary basis to reduce the impact of contingencies that would otherwise create thermal overloads that limit the capability of the transmission system.⁵¹

To exactly estimate the magnitude of transmission investment deferrals enabled by electricity storage, one would need to conduct a detailed transmission planning analysis and examine each potential deferral opportunity. We have not conducted such a transmission planning analysis. Instead, we assume that the benefit of achievable future transmission investment deferrals is approximately equal to the average annual system-wide transmission cost for every unit of peak demand reduced. Thus, to estimate the value of potential transmission investment deferral, we

⁵⁰ Note that storage devices located at generator nodes in the transmission system would not reduce the net peak load that the T&D system would need to support. However, storage deployed at other targeted locations in the transmission system may be able to defer other types of transmission upgrades.

⁵¹ For a discussion of these types of transmission-related benefits, see the proposal by Western Grid Development for which FERC has approved incentive rates of returns in January 2010 (see 130 FERC ¶ 61,056).

used the average annual transmission cost per kW of summer coincident peak (CP) load at \$36/kW-year, multiplied by the peak load reduction at each storage deployment level.⁵²

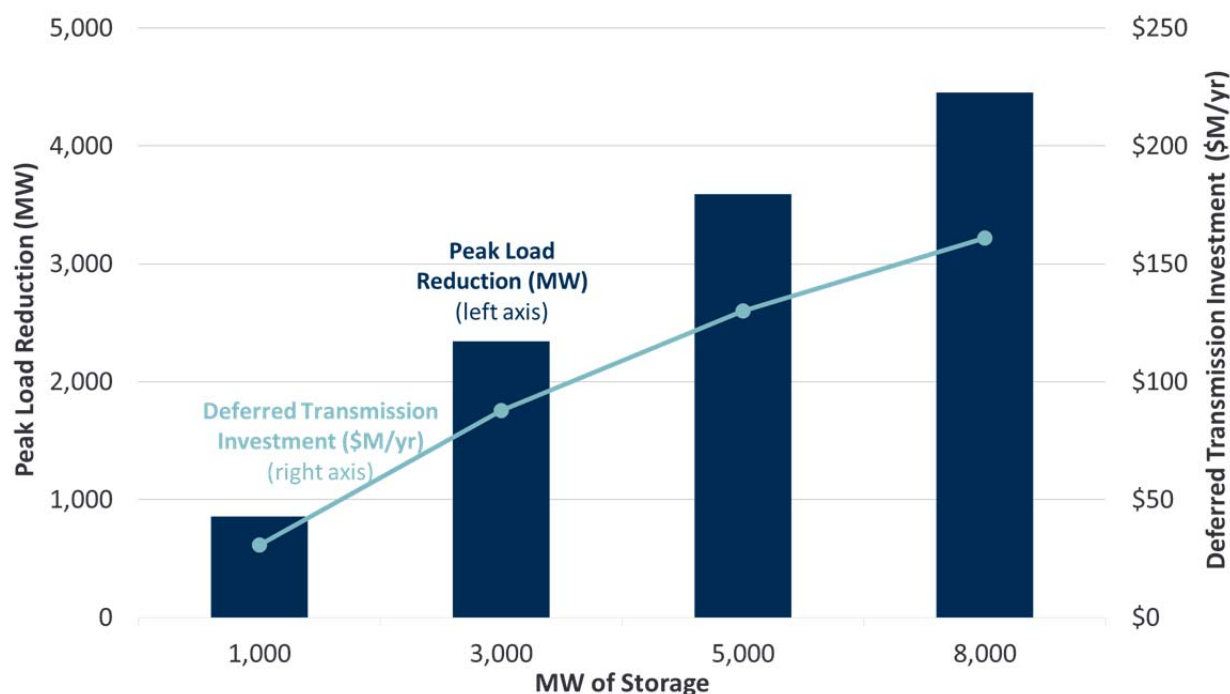
For locations where the incremental cost of transmission upgrades per kW of peak load is less than the average cost of the existing system, using this average cost will overstate the value of deferred transmission upgrades. On the other hand, for locations with high upgrade costs, our approach will understate the value. Our average cost approach is a conservative proxy for transmission investment deferral benefits because: (a) the marginal costs of upgrading a constrained system tend to be above the average cost (thus not yet already upgraded); (b) the average transmission rates in ERCOT have been increasing, indicating that marginal costs are in fact above average costs; and (c) targeted deployments may make it possible to focus storage development into high-value locations or grid services beyond just peak load reductions.

To estimate the magnitude of peak load reductions from storage, we rely on the results of our wholesale power market simulation, comparing peak load without storage to net peak load with storage. As shown in Figure 12 below, each incremental unit of storage reduces peak load by a declining amount. This decreasing effect occurs because electricity storage is energy-limited and the number of discharge hours needed to further reduce peak load increases (*e.g.*, the load duration curve becomes flatter with more storage).⁵³ The chart shows that deploying 5,000 MW with 15,000 MWh of storage in ERCOT would reduce peak loads by approximately 3,600 MW. It also shows that using the average cost of \$36/kW-year in transmission investment deferral benefits yields a storage-related value of approximately \$130 million per year at the 5,000 MW storage penetration level.

⁵² Transmission costs reflect the transmission rate applicable to one class of customers in Oncor's system as of 2014 (\$2.840117 per 4CP kW), escalated with inflation to 2020 nominal dollars. This 2014 transmission rate is in line with the transmission rates applied to other customer classes and in other distribution systems across ERCOT, see PUCT (2014).

⁵³ We examine this interaction among storage power, energy, and load duration curve only as aggregated to the ERCOT wholesale market level. A more detailed examination of individual customer segments' load profiles on each feeder in concert with distribution system capabilities would need to be conducted as part of a distribution system plan to identify the best placement of storage to achieve the most beneficial net load reductions. Once such a detailed assessment is done, it could also account for the discrete nature of distribution system upgrades such that some threshold level of load is a trigger point for a major upgrade as discussed further below.

Figure 12
Peak Load Reduction and Deferred Transmission Investments



Notes:

Peak Load reductions are measured as load minus discharge from storage during the coincident peak hour.

Deferred Distribution Investments. In addition to transmission investment deferrals, deployment of storage on the distribution system will also reduce peak load growth on the distribution feeders. While the overall distribution system spending will increase with the deployment of distributed storage devices, the deferral of some of the traditional distribution investments will create a partial offset to those cost increases. As a substitute for conducting a full location-specific distribution system needs assessment with and without storage, we assume that each kW of discharge capability from storage can reduce one kW of distribution system load growth and defer incremental distribution system investments.⁵⁴

We estimate the value of distribution investment deferrals on the Oncor system using two approaches. The first approach is based on targeted investments at specific substations and the second approach is based on an average system investment cost similar to the approach we use for estimating the transmission investment deferrals. Conducting the distribution system deferral using these two approaches allows us to benchmark the range of distribution upgrade costs that electricity storage is likely to defer. Once we have a range of deferral cost, we assume that the highest-value deferral opportunities would be pursued first.

⁵⁴ Unlike transmission costs, which we assume are driven primarily by ERCOT coincident peak loads, we assume that distribution system costs are driven by non-coincident peak loads on each feeder so that each kW of storage would reduce distribution feeder peak loads by one kW.

First, to obtain substation-specific estimates, we worked with Oncor to identify the number of high-value distribution investment deferral opportunities within the Oncor system, where reducing the distribution peak load would defer a major substation investment. The types of upgrades we examined were the installation of new distribution substations to expand existing feeders, adding new transformers to existing substations, and upgrading existing transformers to a larger size. While there are many other types of distribution system cost deferrals that could be considered, we focused only on these three types of investments for the purpose of our analysis. We then sized a potential storage asset at each substation such that it would be large enough to offset 15 years of load growth, thereby deferring the need for the identified upgrade for 15 years. Table 3 below provides an illustrative calculation of these values for two locations with the same upgrade costs (the approximate cost of building a new distribution substation), in locations with low and high load growth. As the table illustrates, locations with low load growth will have a higher investment deferral value when measured on a \$/kW-yr basis because distribution investments can be quite lumpy, and under low load growth, even a small investment in storage can defer a costly substation investment for many years.

We estimated the total number and size of these substation cost deferral opportunities based on Oncor's current distribution plan, which includes upgrades of varying costs and in locations with different levels of load growth. We also considered that some storage deployments may occur at locations that would not have needed upgrades in the immediate year, but that would have needed upgrades one to four years in the future. Locations where the upgrade would not be needed until a later year have lower realized deferral value. Using this approach, we estimated 210 MW of storage applications with high deferral value on the Oncor system, or approximately 580 MW when extrapolated to all of ERCOT.

Table 3
Example of Location-Specific Distribution Cost Deferral in High and Low Load Growth Locations

			High Load Growth Location	Low Load Growth Location
Starting Peak Load	[1] (MW)		10	10
Peak Load Growth Rate	[2] (%)		3%	1%
Peak Load in 15 years	[3] (MW)		15.6	11.6
Battery Size to Defer Upgrade 15 Years	[4] (MW)		5.6	1.6
Substation Upgrade Cost	[5] (\$)		\$3,000,000	\$3,000,000
Investment Cost Avoided by 15-Yr Deferral	[6] (%)		60%	60%
Deferral Savings	[7] (\$/kW)		\$323	\$1,118
Charge Rate	[8] (%)		7.9%	7.9%
Deferral Savings	[9] (\$/kW-yr)		\$25	\$88

Notes:

[1] and [2]: Illustrative assumptions are approximately consistent with substation in Oncor's system.

[3]: $[1] \times (1 + [2])^{15}$

[4]: $[3] - [1]$

[5]: Illustrative assumption approximately consistent with the cost of building a new substation.

[6]: NPV of deferring investments for 15 years, consistent with Oncor financing cost rates.

[7]: $([6] \times [5]) / (1,000 \times [4])$

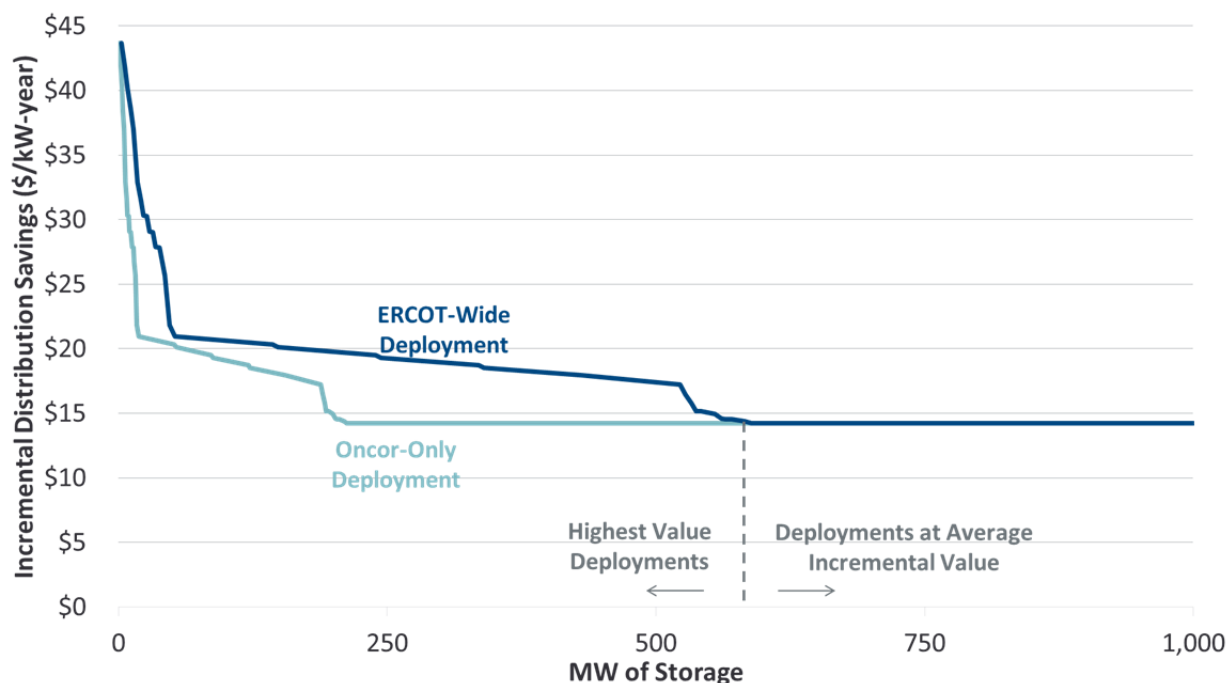
[8]: Payment on a level-real annualization of [7], levelized over a 30-year distribution investment life.

[9]: $[7] \times [8]$

Second, we assumed that in addition to these high-value opportunities, storage deployment in any location would be able to provide some average level of distribution investment deferral. These average-value investment deferrals would be achieved in proportion to peak load reductions, given that peak load growth is the primary driver of incremental distribution investment costs. Based on Oncor's average annual distribution investments and average load growth in 2014, we estimated a levelized annual distribution-investment-deferral value of \$14 per kW of storage (\$14/kW-year).⁵⁵ Figure 13 below summarizes these incremental values of distribution deferral opportunities, assuming that the highest-value opportunities are pursued first.

⁵⁵ Annual distribution investment on the Oncor system will likely increase relative to the recent past few years for which we have investment data. Thus, the estimated value of distribution investment deferral benefits likely is conservatively low.

Figure 13
Estimated Incremental Distribution-Investment-Deferral Savings



Sources and Notes:

Distribution deferral savings decline to the \$14/kW-yr average incremental value at approximately 580 MW for ERCOT-wide deployment and 210 MW for Oncor-only deployment.

Total Deferred T&D Investment Savings. Our estimates of the combined average annual benefits of deferring transmission and distribution investments through storage range from \$35 to \$48 per kW-year of storage deployed. The higher end of this range (\$48/kW-year) is associated with 1,000 MW of storage on an ERCOT-wide basis because the highest-value opportunities are pursued first, while the lower end of this range (\$35/kW-year) is associated with 8,000 MW of storage.

These estimates are on the lower end of the T&D deferral savings reported in other studies of storage-related benefits. For example, a 2013 study of the peak-load reducing benefits of energy efficiency policies found that the average annual benefits of T&D deferral savings ranged from approximately \$20 to \$170 per kW of peak-load reduction for utilities in New England.⁵⁶ Sandia (2010), which we reviewed in Section II of this report, estimated T&D savings in the context of energy storage and found one-year-deferral values ranging from \$481 to \$1,821 per kVA of storage, which would annualize to savings of approximately \$40–\$140/kVA-year under Oncor’s financing assumptions. An earlier report, Sandia (2004) estimated deferred T&D savings at \$880/kW-year for the first deferred year and \$264/kW-year for the second deferred year, but did not calculate the average savings over the life of typical distribution system investments.⁵⁷ EPRI

⁵⁶ See Hornby, *et al.* (2013).

⁵⁷ See Sandia (2004), pp. 16–20.

(2010) estimated that the value of mobile energy storage could defer transmission investments at a value of \$208–\$354 per kW of storage per year of deferral.⁵⁸

Our estimates are much lower than those in some of these studies primarily because these other studies examine only the benefits associated with short-term deferrals (two years or less) where a large amount of savings can be realized with only small storage size. We assume that storage devices would be sized to defer investment by the life of the storage (which we have assumed to be 15 years), which means that we assume a much larger size of storage for a longer-term deferral than in some of the other studies that focus only on the first incremental deferral. Thus, the estimated benefits associated with distribution investment deferrals are conservative in our study. Further, our estimated distribution-related benefits are quite small compared to Oncor's average distribution annual revenue requirement per kW of peak load, which was \$84/kW-year in 2014,⁵⁹ because many of the costs associated with distribution would not be deferred by storage deployment. Such distribution system costs would include meters, meter-reading, tree-trimming, other operations and maintenance, and many administrative costs.

There have been several regions in the U.S. where electricity storage has been proposed as a potential way to defer T&D spending. For example, Puget Sound Energy is installing a 3 MW battery on Bainbridge Island, WA, to defer distribution investment to accommodate forecasted load growth for about 9 years.⁶⁰ Puget found this to be cost effective even at a battery cost of \$2,300/kW. Consolidated Edison, serving the metropolitan New York area, has filed a proposal with the New York State Public Service Commission to defer the cost of building \$1 billion in major distribution and sub-transmissions upgrades to meet future load growth in Brooklyn and Queens by using a range of distributed resources, including storage, energy efficiency, and distributed generation.⁶¹

Similarly, SCE has applied to the CPUC for approval of 23 storage offers totaling 264 MW that it selected from four counterparties in response to a request for offers to address its capacity needs in the West Los Angeles Basin region of its service area.⁶² The diverse set of storage applications will be deployed both in-front-of-the-meter and behind-the-meter locations on the company's T&D system, and SCE would control the charge and discharge of the storage device. SCE's contracts with storage providers are reported to incorporate guaranteed energy efficiencies on the charge and discharge cycles, operating characteristics (*e.g.*, number of cycles per month or year, number of deep discharges per day/month/year, number of MWh of discharge per year), and responsibilities for charging energy versus auxiliary load for onsite energy needs. While

⁵⁸ See EPRI (2010), p. A-17.

⁵⁹ Data provided by Oncor staff.

⁶⁰ See Balducci, *et al.* (2013).

⁶¹ See Heslin (2014).

⁶² See Cordner (2014).

SCE's solicitation was in response to a CPUC mandate, the storage portion of the SCE-selected capacity resources amount to over five times the minimum amount required by the CPUC.

2. Reliability Improvements on the Distribution System

Grid-integrated electricity storage can improve the reliability and resiliency of supplying electricity to end users at both the transmission and distribution levels. For example, the ability to inject energy can help maintain grid reliability and provide black-start services to help re-energize the transmission grid after wide-spread outages.⁶³ Further, on the distribution system, electricity storage can be located near or at customers' sites to provide backup power during transmission or distribution system outages, with the proximity to customers introducing relatively little or no environmental or customer impact compared to other types of backup power. In the event of an outage on a distribution line, the system can be almost instantaneously switched to the battery, thereby providing uninterrupted power supply for several hours while the fault is investigated and resolved.⁶⁴ The causes of these distribution outages can range from storm damage to unexpected equipment failures. Oncor has already installed 25 kW, 25 kWh batteries in South Dallas neighborhoods for the sole purpose of providing backup power. Each battery can provide power for three to five houses for three hours.⁶⁵

To deploy electricity storage in the most effective and efficient manner for reducing customer outages, a distribution utility would first install storage devices at locations with low reliability or high-value end users, thereby avoiding the most costly and frequent outages. Depending on the location of the storage devices and the location of the fault, there may be instances where a storage device is unable to completely eliminate interruptions to customers' service. At times, the outage may last longer than what can be covered by the storage.

The value of avoiding power outages is generally estimated at customers' VOLL, which is an estimated measure of how different electricity users value access to reliable electricity. We have reviewed a number of studies estimating VOLL by customer classes and found that the VOLL of residential customers tends to range from \$1,000 to \$5,000/MWh, while the VOLL of commercial and industrial (C/I) customers tends to range from \$10,000 to \$80,000/MWh.⁶⁶ For

⁶³ The Long Island Power Authority (LIPA) included storage as part of a 1,630 MW resource procurement effort, in which up to 150 MW of storage will be procured to assist black-start operations. See LIPA (2013).

⁶⁴ For example, a 1 MW sodium-sulfur (NaS) battery installed in a remote town in British Columbia allows the town to operate islanded from the grid in the event of a transmission line outage. Two weeks after its installation, the town experienced the first outage and the battery system provided backup power for 7 hours while utility crews repaired the line to the town. See S&C Electric Company (2014).

⁶⁵ See Cameron (2014).

⁶⁶ For example, Sullivan, *et al.* (2009) conducted a meta-analysis that combines the results of 28 individual VOLL studies, finding an average VOLL of \$2,600/MWh for residential customers and an

the purpose of this analysis, we assume that the average VOLL for commercial and industrial customers is \$20,000/MWh and the average VOLL for residential customers is \$3,000/MWh. These assumed values are consistent with the \$9,000/MWh system-wide VOLL that the PUCT and ERCOT use for wholesale market pricing purposes.⁶⁷

To assess the value of reducing customer outages, we analyzed historical outage statistics on Oncor's distribution substations and feeders, approximately 3,000 locations in total. We estimated the number and duration of customer interruptions that could have been avoided if Oncor had deployed storage assets on each distribution feeder to maintain customer power supply during outage events.⁶⁸

We use five years of historical outage patterns to simulate a storage deployment targeted at feeders with lower than average reliability, recognizing that historical outages are an imperfect predictor of future outage patterns. Using three years of the available historic data, we developed a targeted (but imperfectly-optimized) storage deployment strategy by first selecting locations to install storage at feeders with the highest outage frequencies. During this process, we ignored the impact of storm-related outages in the historical outage data as storms can result in large outage events that may not be indicative of a feeder's typical level of reliability. We assume a minimum storage installation equal to the average load at each feeder. This minimum installation requirement based on feeder size generally exceeds the typical outage size, which significantly reduces the estimated outage benefit per MW of installed storage device relative to the hypothetically achievable level where storage deployment is optimized to the outage size.

We then use the remaining two years of outage data to estimate the customer interruptions that the selected storage deployment would likely avoid if fully-charged storage devices could be used to supply all of the customers that experience an outage on that feeder.⁶⁹ Recognizing, however, that storage devices will not always be fully charged or may not be able to deliver power to all

Continued from previous page

average value of \$25,000/MWh for medium and large C/I (in 2008 dollars). Similarly, a literature review by MISO (2006) found that estimates of VOLL ranged from \$1,500 to \$3,000/MWh for residential, \$10,000 to \$50,000/MWh for commercial, and \$10,000 to \$80,000/MWh for industrial loads (in 2005 dollars). A recent study undertaken on behalf of ERCOT by London Economics International (2013) found VOLLs ranging from \$3,000/MWh to \$53,907/MWh for C/I customers and from \$0/MWh to \$17,976/MWh for residential customers.

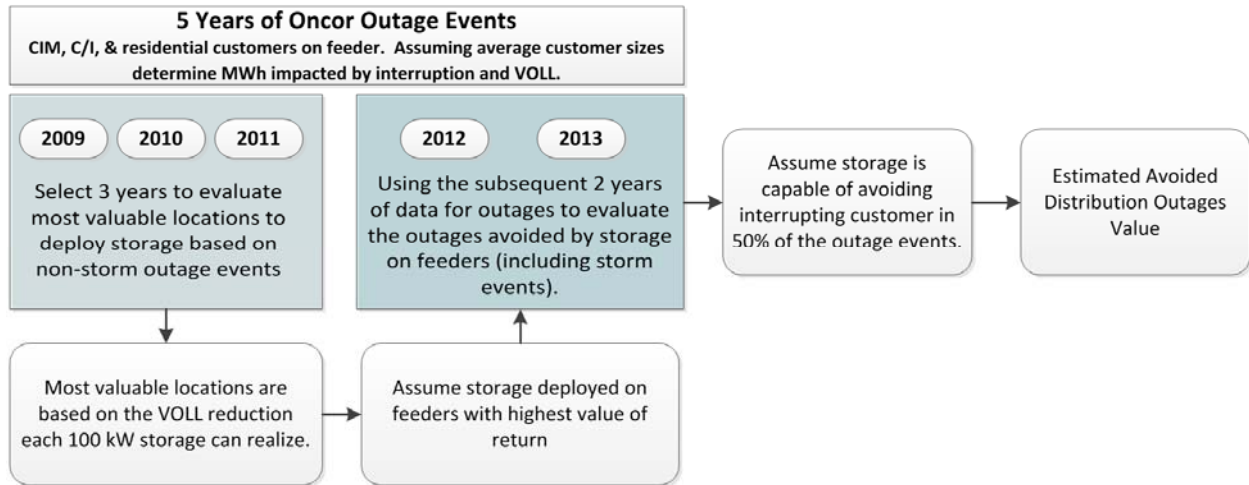
⁶⁷ See ERCOT (2014a).

⁶⁸ The raw data were based on customer interruption-minutes that we converted into MWh of interruptions based on the number of customers by class at each feeder and the average customer sizes of 17.6 kW for C/I customers and 1.8 kW for the average residential customer. Average residential customer size of 1,300 kWh/month was provided by Oncor, and average C/I customer size of 12,720 kWh/month is based on EIA data, see EIA (2014).

⁶⁹ We conducted this same analysis using three years of outage "training data" and two years of outage "test data" using every combination of possible years, although to simplify our description we report only one combination of training and test data.

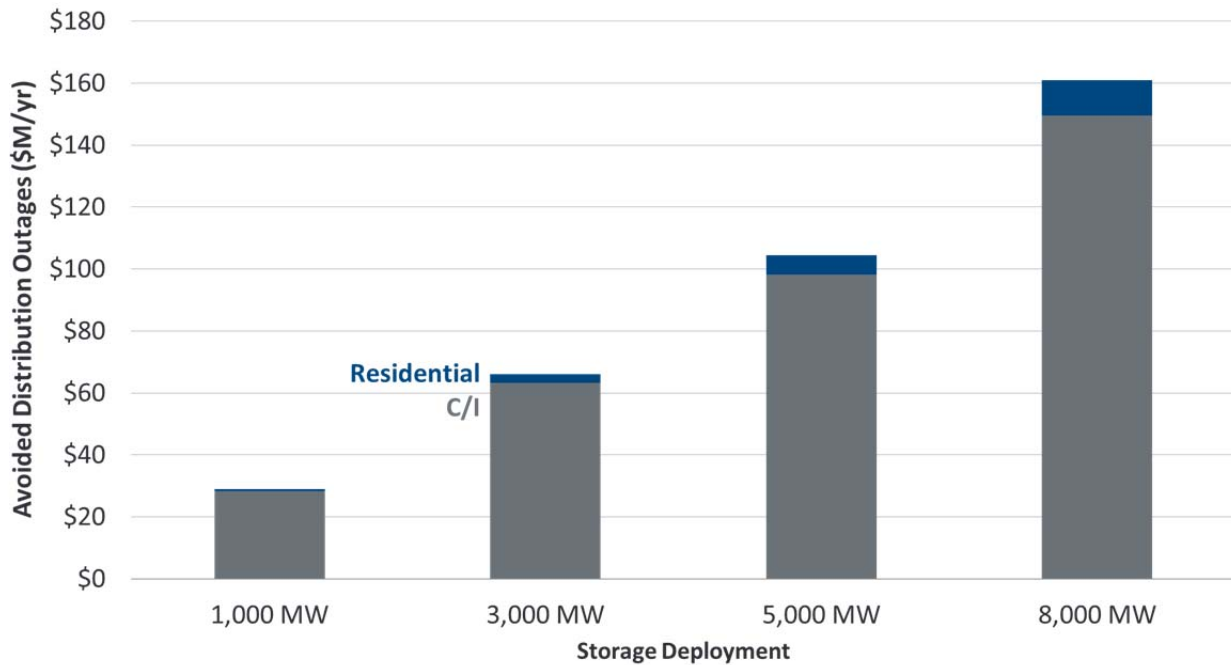
customers affected by the outages, we reduced the estimated outage benefit to only 50% of the initial estimate. Figure 14 below summarizes the method we used to estimate the value of avoided distribution outages.

Figure 14
Process for Determining Distribution Outage Value



Further, Figure 15 below illustrates the realized value of avoided distribution outages to residential and C/I customers. Because C/I customers’ electricity usages are typically larger than residential customers’ usage and C/I customers typically place more value on uninterrupted electricity (thus a higher VOLL), the selected feeders for storage deployment tend to be those with a large number of C/I customers. The combination of high VOLL for C/I customers and the selection of feeders with a high number of C/I customer results in a higher outage reduction value than if the storage had been deployed at feeders that primarily served residential customers.

Figure 15
Estimated Total Annual Value of Avoided Distribution Outages by Customer Class



Notes:

Assumes an ERCOT-wide deployment of storage, results are originally based on deploying storage on Oncor’s feeders, scaled up to an ERCOT-wide deployment based on Oncor’s share of ERCOT load, after applying the 50% discount.

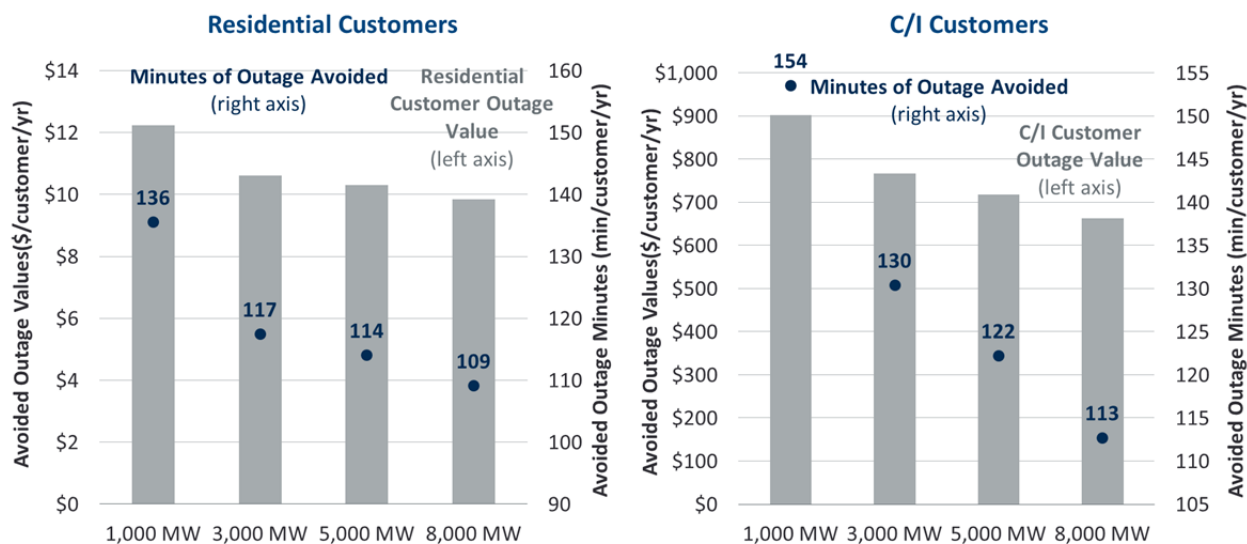
The weighted-average VOLL across all avoided outages is approximately \$13,200/MWh. This is higher than the VOLL of \$9,000/MWh that ERCOT uses in its wholesale market design, but consistent with our deployment strategy that first selects the highest-value locations, which typically have higher C/I customer counts. Of the weighted-average VOLL of \$13,200/MWh, the avoided VOLL for residential customers contributes between 3% and 7% of the total outage reduction value.

Figure 16 below compares the values associated with avoiding outages for the average customer on a feeder where storage has been deployed. The typical residential customer uses approximately 1,300/kWh per month with an assumed VOLL of \$3,000/MWh, while the typical C/I customer uses approximately 12,700kWh per month with an assumed VOLL of \$20,000/MWh. The blue dots in Figure 16 show the estimated number of outage minutes that storage would avoid and the grey bars show the values associated with those avoided outages. In the left panel of Figure 16, we show that deploying the first 3,000 MW of storage on the ERCOT system would reduce power outages experienced by a typical residential customer on the targeted feeders by approximately 120 minutes per year (with a worth of about \$10/year), including partial mitigation of storm-related outages.

The right panel of Figure 16 shows the comparable results for C/I customers. The scale of those avoided outages and associated values are over 70 times greater for a typical C/I customer, with the estimated average annual outage reduction to be approximately 130 minutes at a 3,000 MW

ERCOT-wide deployment level. Because C/I customers are ten times larger and place a much greater value on avoided power outages, the average C/I customer would realize a reliability value of approximately \$750/year for customers located on feeders with storage.⁷⁰

Figure 16
Avoided Outage Value and Outage Duration per Customer by Customer Class



Sources and Notes:

Results are based on our analysis of five years of Oncor outage data, with the storage deployed throughout ERCOT. The average duration of outages avoided declines with storage deployment because early installations are targeted to the feeders that could benefit the most from outage prevention. Residential value is based on a standard residential consumer using 1,300 kWh/month and a VOLL of \$3,000/MWh. C/I value is based on an average customer size of 12,700 kWh/month and a VOLL of \$20,000/MWh.

The same results can be used to estimate the reduction in Oncor’s System Average Interruption Duration Index (SAIDI) metric at each storage penetration level. We estimate that if Oncor were to install 3,000 MW of storage on its system, its system-wide SAIDI would decrease by 10%.⁷¹ While improving distribution system reliability does not translate directly to cost savings through customers’ electricity bills, increasing the reliability of the system may help defer the need for investing in other reliability improvement measures, whose separate values (aside from the deferred T&D investments) are not estimated in this report.

D. OTHER POTENTIAL STORAGE VALUES NOT QUANTIFIED

As discussed in Sections I and II of this report, deploying storage onto T&D systems within the ERCOT system can provide a wide range of different types of benefits. Our estimate of the system-wide storage value covers only some of these potential benefits. Other additional benefits

⁷⁰ Assumes an average commercial or industrial customer consumes 12,700 kWh per month.

⁷¹ Calculation is based on the reduction in non-storm outage events on Oncor’s system.

that we have not estimated, that may or may not be additive to those that we have estimated, include:

- **Real-Time Wholesale Market Benefits.** Our wholesale market simulations focused on the energy and ancillary services value of electricity storage that would be realized in the day-ahead market, which is based on forecast, not actual, system conditions, including load and wind generation. Because actual system conditions during real-time operations generally differ and, at times, significantly from day-ahead forecasts due to variance in load, wind generation, and other factors, such as unanticipated generation or transmission outages, storage facilities can provide incremental balancing benefits that market participants could realize by participating in ERCOT's more volatile real-time energy market. Simulating the interaction between day-ahead and real-time markets adds a level of complexity that we have not yet addressed in our analysis. We also have not estimated the potentially higher value of a focused deployment at ERCOT nodes with higher potential values.
- **Renewable Integration Benefits.** Electricity storage can be used to avoid renewable generation curtailment during transmission constraints by charging when there is excess renewable generation and discharging when load is high. These values can be particularly high on a sub-hourly basis when wind output is more volatile and in real-time when the system operator can be surprised by unexpected highs or lows in load or wind. Many other studies have focused on this aspect of the storage capability and we have not repeated those analyses in this report. We do assume a substantial 8,600 MW of nameplate renewable growth in ERCOT between now and 2020.⁷² However, we only simulated the integration of these renewables in the day-ahead wholesale electricity market on a zonal basis. Thus, the value we estimate does not capture the ability of storage to reduce renewable generation curtailments, which mostly occur in real-time market operations and on a nodal level. Electricity storage's ability to absorb excess generation would also increase the value of renewable energy resources, and such value would be magnified as additional wind and solar generation is added. Further, as renewable penetrations increase, larger amounts of flexible resources will be required to maintain operation of the electric system; storage would help meet a portion of that requirement and reduce its costs. The growing development of renewable generation is likely to increase ancillary services requirements and thus provide additional opportunities for storage to earn revenues from participating in the ancillary services market. We have not estimated the incremental value associated with these aspects of renewable integration, but note that a portion of the value realized via storing excess renewable generation will be captured by our estimate of the day-ahead energy arbitrage value. A larger portion of this value would be captured in an assessment of the incremental benefit of storage in ERCOT's real-time market.

⁷² Consistent with the May 2014 ERCOT capacity demand and reserves (CDR) report, see ERCOT (2014c).

- **Reduction in Regulating Reserve Requirement.** While it is too early to evaluate the full impact of the proposed ERCOT market changes on its ancillary services needs and market design, the experience in PJM shows that after fast regulation resources began to participate in its regulation market, PJM could reduce its overall regulation needs without compromising its system reliability. Since October 1, 2012 when PJM redesigned its frequency regulation market, fast moving resources that participate in the regulation market, such as storage technologies, have grown to provide a combined regulating capability of approximately 490 MW. These fast regulation resources allowed PJM to reduce the amount of regulation requirement from 1.0% of peak load to 0.7% of peak load.⁷³ Storage not only reduces the need to rely on conventional ancillary services resources, but also reduces the overall quantity of ancillary services needed. This experience shows that storage can avoid future generation needs both in terms of generation's ability to meet peak load as well as ancillary service needs. We have not estimated the extent to which storage could reduce ancillary services needs in ERCOT.
- **Reduced Cycling of Conventional Generators.** Deploying electricity storage that charges during off-peak conditions and discharges during peak-load conditions will reduce the extent to which conventional generation units will be required to cycle up and down. Reduced cycling can increase generators' reliability, avoid certain maintenance costs, and increase the lifespan of their equipment and thus their asset value. A study of power plants in the Western U.S. found that more cycling increases conventional power plants' maintenance costs and forced outage rates, accelerates heat rate deterioration, and reduces the lifespan of critical equipment and the generating plant overall. For example, that study estimated that the total hot-start costs for a conventional 500 MW coal unit are about \$200/MW per start (with a range between \$160/MW and \$260/MW). The costs associated with equipment damage account for more than 80% of this total.⁷⁴ Our analysis captures the fuel and variable O&M costs of cycling conventional generators, but not the impact on plants' capital needs for major maintenance and refurbishment.
- **Emissions Reduction.** Electricity storage can increase the overall fuel efficiency of a power system by reducing the dispatch of inefficient peaking units during peak-load periods and increasing the dispatch of more efficient generation during off-peak periods, though these gains are offset by the round-trip efficiency of storage. Such efficiency gains can reduce power plant emissions, particularly in systems that are dominated by renewable, nuclear, or natural gas generation during off-peak periods. In power systems where coal plants represent a significant share of marginal resources during off-peak periods (this is the case in systems such as PJM and MISO, but is not the case in ERCOT), the efficiency gain may not translate to emissions reductions. Because even in off-peak hours the marginal resource type in ERCOT is often an efficient gas CC, our market simulations show that deploying storage on the current ERCOT system is approximately

⁷³ See PJM Interconnection Regulation Senior Task Force (2013).

⁷⁴ See Kumar, *et al.* (2012).

emissions neutral. Storage, as part of an efficient wholesale market, might play a more substantial role in reducing or mitigating emissions in the future if a more substantial pricing regime for CO₂ or other emissions emerges in the future, as the economics would create more incentives for storage and the system as a whole to avoid producing these pollutants.

- **Reduction of Line Losses.** Deploying electricity storage on the distribution system will reduce loading on the circuits during periods of peak demand, and will also reduce average losses incurred on the T&D system. Because losses increase with the square of line loadings, the reduction in losses during peak load conditions due to storage discharging close to load will exceed the increase in losses incurred when charging the storage during off-peak conditions. We developed a rough estimate of this effect for the Oncor system and found that its additional annual value was approximately \$4–5 per kW of installed storage capacity, declining slightly with increasing storage deployment. Since this additional value is modest compared to the estimated range of value associated with deferring T&D investments, we have not included this value in the overall results presented in this report.
- **Reduced Wear and Tear of Distribution System Elements.** Reducing circuit loadings during peak load conditions also reduces the wear and tear of distribution equipment, *e.g.*, due to thermal stressing or frequent tap changer resetting. While this will tend to increase equipment life and defer distribution system replacement needs, we have not analyzed the potential magnitude of this benefit.
- **Increased Power Quality.** Storage can be deployed in the distribution system to improve the quality of power delivered to customers. The electronics associated with storage devices can be designed to inject reactive power to offset voltage drops caused by momentary load spikes on the distribution system (such as those caused by motor startups) or to inject energy to stabilize the local system (such as may be necessary due to fluctuations in distributed solar generations under cloudy weather conditions). We have not attempted to quantify this benefit.

These additional benefits may provide significant system-wide value beyond what we have estimated in our analysis. However, as noted in the discussion of the individual types of benefits, estimating the additional overall value provided by these benefits is challenging analytically and great care would need to be taken to avoid double-counting the overlapping portions of these values.

IV. Aggregate Value of Electrical Energy Storage

We evaluate the net benefits of adding electricity storage in Texas from the perspectives of wholesale market participants, society as a whole, and retail electric customers. We first consider how a merchant developer may analyze the market-based incentives for storage investment compared to investment costs. We then report the societal, system-wide benefits of

storage, regardless of whether suppliers or customers would realize those benefits, and estimate the deployment scale that would likely offer the highest system-wide value.

Finally, we estimate the net benefits to retail electricity customers if storage assets were deployed under a regulated framework that would allow the full value of the storage assets to be captured. In this analysis, we assume that customers would pay for the storage investments just as they pay for T&D investments. Customers would then obtain offsetting reductions in retail electricity costs from the storage deployment through deferred T&D investments, refunds from the wholesale market auction proceeds, and reduced power purchase costs. Customers would additionally benefit through increased system reliability in the form of reduced distribution outages, although the improved reliability does not directly affect the customers' electricity bills. The storage would likely be deployed and operated in ways that provide a number of additional benefits that we have not analyzed, as specified in III.D.

A. THE MERCHANT VALUE OF STORAGE

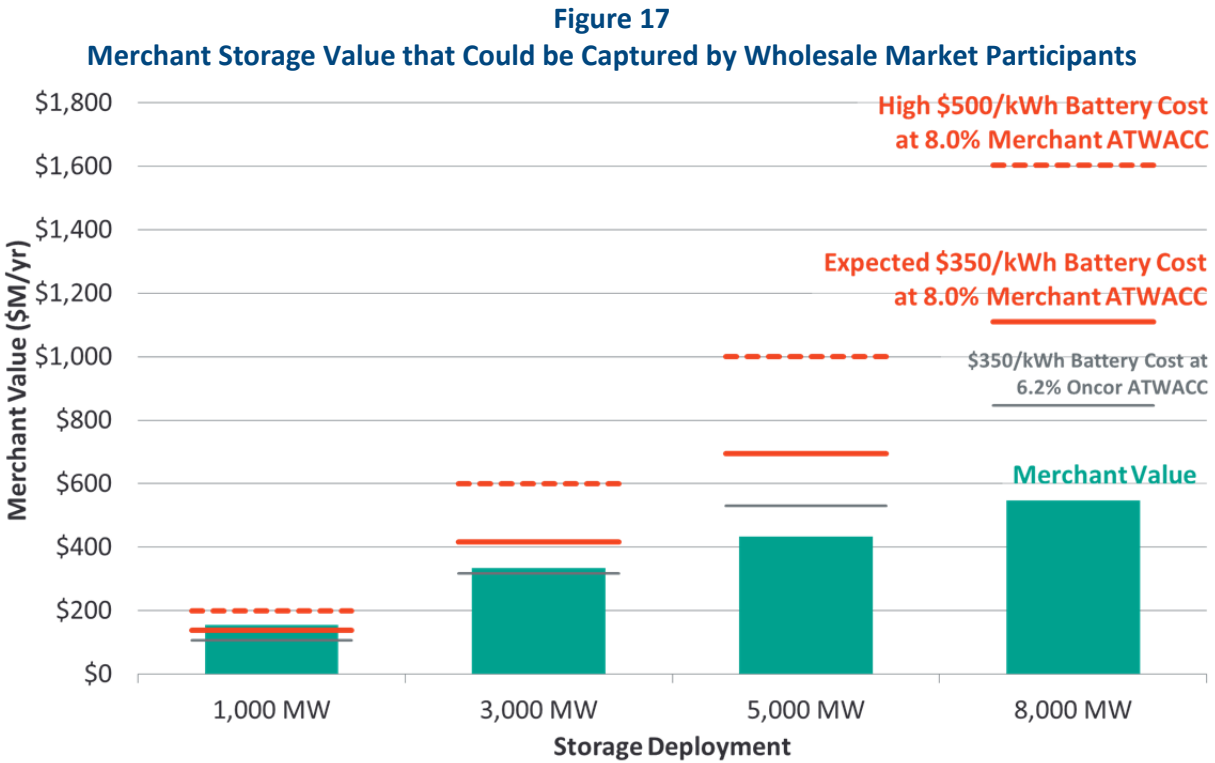
To assess whether storage investment might be attractive to wholesale market participants, we estimate the net revenues that storage could earn in ERCOT's wholesale power markets.⁷⁵ Figure 17 below presents our estimate of expected annual merchant value and costs at varying levels of storage deployment. The top of each bar shows the total annual market value that merchant investors could privately capture in ERCOT's energy and ancillary services markets. This realized merchant value is identical to the value reported on a per kW-year basis in Section III.B.2 above, except that we now report the value on a total market-wide basis.

Figure 17 compares this merchant value (shown in the bar) to the annualized storage costs that a merchant developer would face (shown as the red horizontal lines), assuming an 8% ATWACC and 15-year life as previously discussed. We also compare the merchant value obtainable in ERCOT's wholesale power markets with the annualized storage costs that a regulated TDSP would face (shown as the grey lines, at 6.3% ATWACC, 15-year battery life, and 30-year power system life). As explained earlier, comparing annualized costs and annual benefits is equivalent to an NPV analysis normalized for the life of the investment, as long as we assume that realized benefits will increase with inflation.

Figure 17 shows that the wholesale market benefits of storage alone are limited in comparison to storage costs. This discrepancy between benefits and costs is consistent with the observation that private investments in storage have been minimal to date. Wholesale market value that can be captured is well below current storage costs, which still exceed \$500/kWh. However, if storage costs drop to the \$350/kWh benchmark used in this study, a modest amount of storage (possibly

⁷⁵ If certain retail electricity customers are interested in deploying electricity storage on their premises, we assume that they too would be interested in capturing the values associated with transacting in the wholesale markets. Thus, the merchant value we estimate in the report is the value that any storage investor should be able to capture via participating in the wholesale market either through direct or third-party participation.

up to 1,000 MW) could break even purely on a merchant, wholesale-market basis. However, the aggregate merchant value is well below storage costs at greater deployment scales. This value to cost gap is due to merchant participants' inability to directly capture values outside of the wholesale market, and within the wholesale market, the ancillary services market opportunities would quickly be saturated and the wholesale energy price difference between peak and off-peak periods (on which merchant investors rely) diminishes as storage deployment increases.⁷⁶



Sources and Notes:

Merchant value represents the margins that a merchant investor would receive by participating in ERCOT’s energy and ancillary services markets, assuming storage with a 3-hour discharge capability, 85% round-trip efficiency, and no other variable operations and maintenance (VOM) costs. Storage costs of \$350/kW-y are based on battery vendors’ estimates of \$200/kWh as quoted to Oncor, plus an Oncor-estimated installation cost of \$150/kWh, plus fixed operations and maintenance costs equal to 1% and 2% of investment costs for the “expected” and “high” cost levels.

B. SYSTEM-WIDE SOCIETAL BENEFITS

Figure 18 below reports the estimated system-wide societal value of electricity storage, when deployed on a distributed and grid-integrated basis, regardless of who receives those benefits. In the top chart, we report the total annual costs and benefits of deploying increasing levels of storage in millions of dollars per year. The colored stacked bars show the estimated net benefits based on four components of storage value from an annualized, system-wide societal perspective,

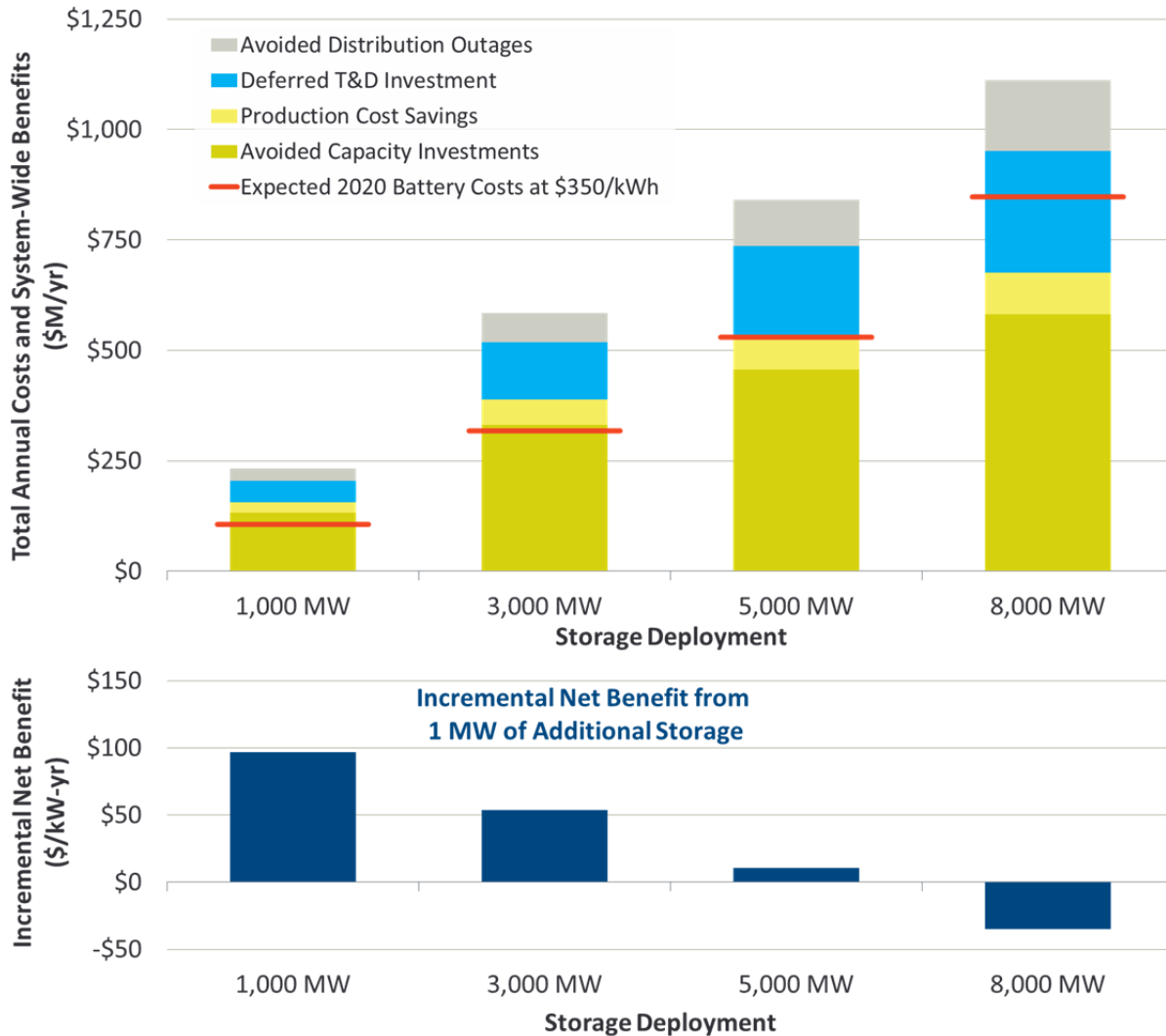
⁷⁶ Note that we estimate a relatively more gradual decline in merchant value compared to many other studies estimating the value of storage. This is because we account for the partially offsetting effects of generation investment response, such that wholesale power prices remain high enough to attract needed conventional generation investments as explained earlier.

including: (1) the value of reduced distribution outages; (2) deferred T&D investments; (3) production cost savings; and (4) avoided generation investments. These estimated annual benefits of storage are then compared with annualized storage costs, shown by the red lines.

The top chart of Figure 18 shows that the total benefits exceed the costs by a substantial margin even at a relatively high ERCOT-wide storage deployment level of 8,000 MW. By comparing the *difference* between the top of the stacked bars and the red lines, the same chart also shows that the *net* benefits in absolute dollars are maximized at a deployment level of approximately 5,000 MW, after which the *net* benefits begin to decline due to the diminishing returns from investments. The bottom chart in Figure 18 shows the incremental net benefits (or incremental benefits minus incremental costs), in \$/kW of storage, of adding one more MW of storage onto the ERCOT system. Incremental benefits exceed the incremental costs up to approximately 5,000 MW of deployment.

These results indicate that at a storage cost of \$350/MWh and the forecast system conditions for 2020, the ERCOT system-wide benefits are maximized at a deployment of approximately 5,000 MW. Beyond 5,000 MW, the incremental value of installing additional storage facilities falls below its cost. If storage costs fall below \$350/MWh, a larger amount of distributed storage investments would become beneficial.

Figure 18
System-Wide Annual Benefits Compared to Expected 2020 Storage Costs
 Top: Total Benefits and Costs, Bottom: Net Incremental Benefits



Sources and Notes:

The Expected 2020 Battery Costs are based on Oncor's 6.3% ATWACC, with 15- and 30-year assumed lifetime for the battery and balance of plant respectively.

C. CUSTOMER BENEFITS

While the system-wide, net societal benefit is the appropriate metric for forming policy decisions, regulators and utilities also need to be concerned about the benefits and costs to electricity customers. If the electricity storage investment is funded through a T&D utility's regulated rates, then retail customers will be paying for the investment, thus we evaluate the potential benefits and costs to electricity customers.

While not all of the economic benefits of electricity storage would be received directly by retail customers, we assess the likely impacts on average customer bills and reliability as a proxy to

estimating the overall value of storage from a customer perspective. If customer bills decrease or reliability increases due to the storage investment, then customers receive a net benefit from the investment. However, if customer bills increase by more than the value of reliability improvements, then customers are paying more than the value they receive.

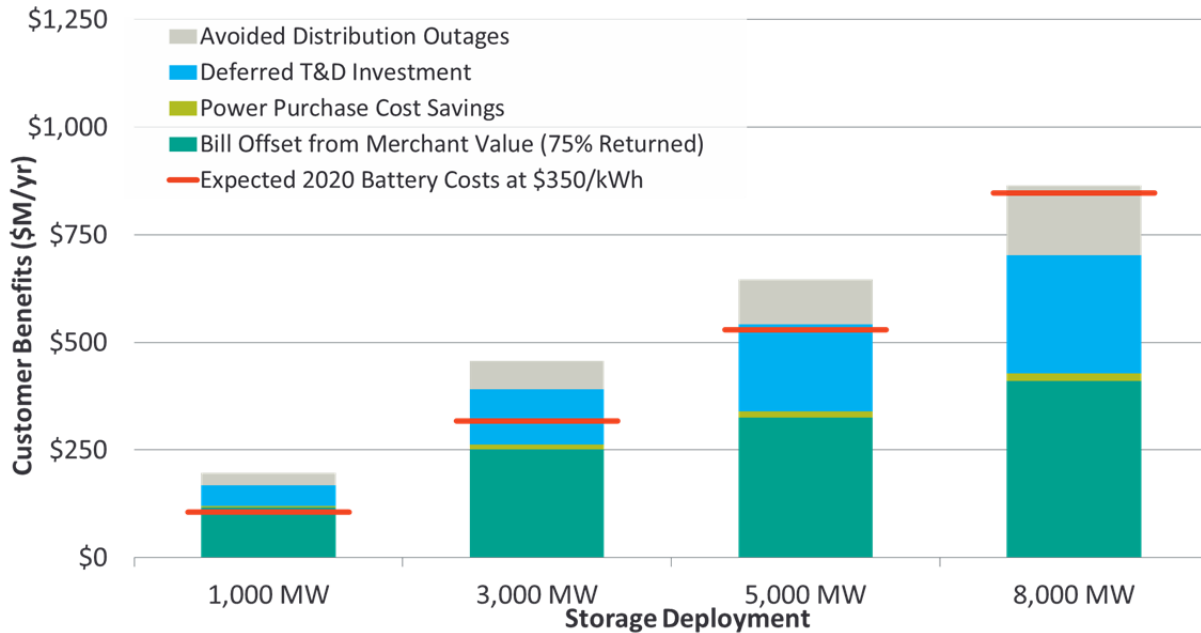
The net benefits of storage from a customer perspective are summarized in Figure 19 below. Customers realize most (but not all) of the benefits we estimate from a societal perspective. Benefits realized by customers include the value associated with deferred T&D investments, which help offset the costs customer incur by paying for the storage. Improved reliability is also a direct benefit to customers, although it does not affect customer electricity bills. In addition, customers would benefit from power purchase cost savings and offsets from merchant value received through the auction proceeds. Since the use of storage can reduce power purchase costs by reducing power purchases during system peaks (net of any increases in the cost of purchases during off-peak periods), this value will directly affect customer bills subject to retail ratemaking mechanisms. As we explained in Section III.B.1, after considering the market price impacts of generation investment response, we estimate that power purchase cost savings are quite small across a wide range of storage investments.

Since we envision that installed storage facilities will be used by independent third-parties to participate in the ERCOT wholesale energy and ancillary services markets, the value of this wholesale market participation would be obtained as an offset to customer bills through an auction process as discussed further below in Section VI. If storage were to be deployed by T&D utilities with the investment costs recovered through regulated retail rates, we would recommend a regulatory framework under which retail customers who pay for the storage assets would also receive a portion of the merchant revenues earned in wholesale markets. For the purpose of our analysis, we assume that approximately 75% of merchant market value would be returned to customers through such auction proceeds, with the remaining 25% kept by the independent entity that contracts for the right to use the storage facilities for participation in the wholesale market.⁷⁷

Figure 19 compares the aggregated customer benefits to the costs of the electricity storage, with the simulated 2020 wholesale market conditions. The stacked bars represent the values that the customers would obtain, while the red horizontal lines reflect expected storage costs at \$350/kWh. This analysis shows that customers are likely to experience significant net benefits even as the cost of the storage investments is recovered through regulated retail rates. We estimate that net customer benefits are maximized between 3,000 MW and 5,000 MW of ERCOT-wide storage deployment. However, note that the current regulations would not allow a battery deployed by TDSPs to be dispatched into the wholesale market, and therefore would not allow the merchant value component to be captured by the TDSPs. Without that value component, it would not be net beneficial for a TDSP to develop storage at a substantial scale.

⁷⁷ This 25% net revenue sharing assumption is approximately consistent with typical net revenue sharing levels for third-party demand response providers. See Newell, *et al.*, (2013) pp. 52–55.

Figure 19
Estimated 2020 ERCOT-Wide Customer Benefits and Storage Costs



Sources and Notes:

The expected 2020 battery costs are annualized based on Oncor’s 6.3% ATWACC, with 15- and 30-year assumed lifetime for the battery and balance of plant respectively.

To take the analysis of customer impacts a step further, Figure 20 below illustrates how a typical Oncor residential customer’s bill would be affected by the deployment of 3,000 MW (9,000 MWh) of ERCOT-wide storage, assuming that 1,000 MW of that storage would be deployed on Oncor’s system and the remaining 2,000 MW were deployed in other distribution systems across ERCOT.

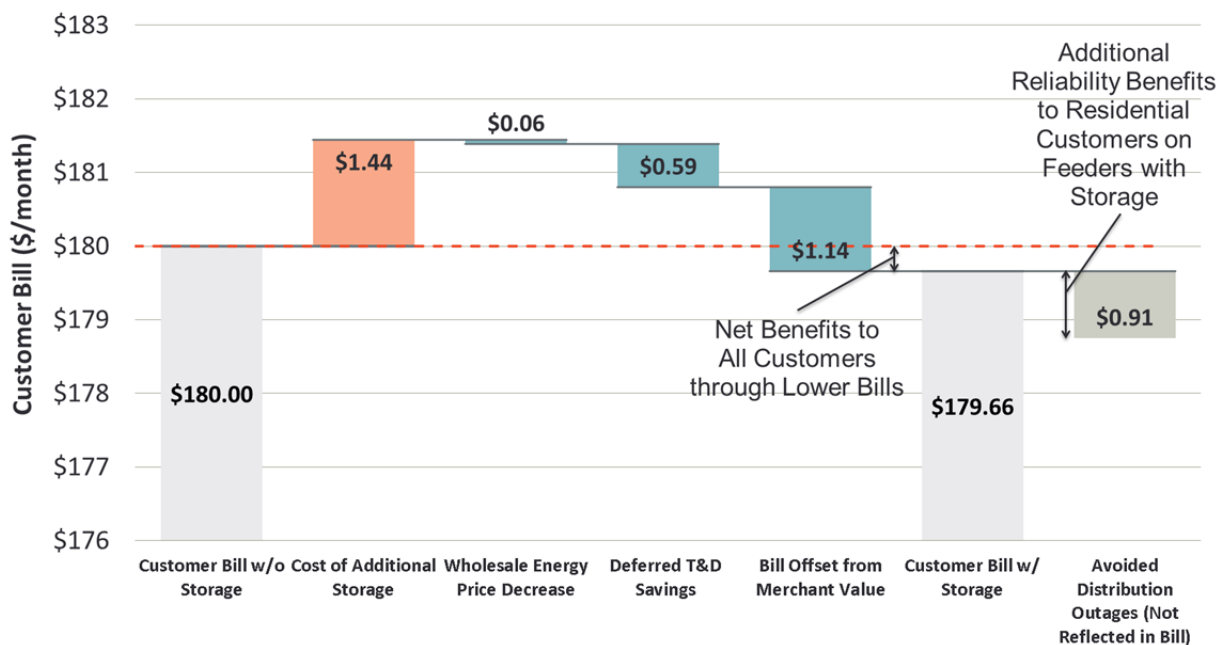
We start with a typical residential customer’s monthly bill, estimated at \$180 in 2020 (based on forecast wholesale power prices without storage). All else equal, deploying 3,000 MW (9,000 MWh) of storage on an ERCOT-wide basis at a storage cost of \$350/kWh would increase Oncor’s average monthly residential bills by approximately \$1.44 as shown by the orange bar. These slightly higher residential customer bills are then offset by the various benefits shown as blue bars. The first benefit is a minor cost reduction due to a slight decrease in the residential load-weighted average of wholesale energy prices, followed by larger bill reductions from deferred T&D investments, and the 75% of merchant value assumed to be credited back to ratepayers. As a result, deploying 3,000 MW (9,000 MWh) of storage on an ERCOT-wide basis would slightly reduce Oncor’s typical residential bill.⁷⁸ In addition to the small residential customer bill

⁷⁸ Note that the cost comparison that we are reporting here reflects the cumulative cost and benefit impacts to a residential customer comparing a no-storage case to a case with 3,000 MW of storage. This residential bill impact estimate reflects *cumulative* costs and benefits, not the incremental bill impact of adding one more unit of storage.

reduction, customers located on feeders with storage would also realize meaningful reliability improvements (shown by the grey bar) and power quality benefits (not quantified).

As indicated by the grey bar on the very right of Figure 20, we estimate that residential customers on feeders with storage would realize approximately \$0.91/month of additional value through reduced distribution outages, even though that value would not be reflected directly in the customer’s bill. Considering that the VOLL for C/I customers (estimated at \$20,000/MWh of lost load) is significantly higher than that of residential customers (estimated at only \$3,000/MWh), the equivalent reliability value for commercial customers on feeders with storage would be approximately seventy times higher than that shown in Figure 20, as explained in Section III.C.2 above.

Figure 20
Residential Customer Bill Impact in 2020 with 3,000 MW of Storage Installed Across ERCOT
 (1,000 MW Installed on Oncor’s System)



Sources and Notes:

We assume that Oncor installs 1,000 MW out of 3,000 MW of storage deployed on an ERCOT-wide basis, with storage costs and wholesale-market proceeds reflecting the same proportion of installations. Oncor customers realize deferred T&D investment benefits based on the 1,000 MW installed on Oncor’s system. The avoided distribution outage value shown is for a typical residential customer on a feeder with storage. Customers not located on a feeder with storage would not realize these reliability benefits.

V. Findings and Implications

The most important question that Texas policy makers may ask is: “Would adding distributed electricity storage in ERCOT produce net benefits for the state, considering the impacts on both investors and electricity customers?” We estimate that if the installed cost of distributed electricity storage falls to \$350/kWh, ERCOT as a whole is likely to benefit significantly from storage deployment. While the incremental benefits per unit of storage diminish as more storage

is added to the system, increasing net benefits are realized until approximately 5,000 MW (or 15,000 MWh) of storage is deployed.

Texas policy makers may also ask: “Why not leave it to the market to make the storage investments?” Our analysis shows that merchant investors, who would only invest in storage if the revenues received in the market would pay for their investment costs, would under-invest in electricity storage relative to the societally efficient scale, because as other studies have observed and we have confirmed, the value of storage is dispersed across the system and merchant investors alone would not be able to collect all of its value directly from the wholesale market. Moreover, pure merchant electricity storage facilities would be under-utilized and not capture the high value offered by targeted deployment within the T&D systems. If electricity customers are left to make the investment themselves, their interests in avoiding power outages would be well-aligned with the T&D utilities’ interests, except that the TDSPs will be in a much better position to select and deploy the storage to capture other benefits, including T&D cost reductions and, through third parties, capture the wholesale market value of the storage assets.

Alternatively, one may ask: “Why wouldn’t the transmission and distribution utility go ahead and install storage, if deploying storage can reduce T&D costs and customer outages?” Based on our estimate of benefits associated with deferred T&D investments and the value of improved distribution reliability, we find that those values alone do not justify deploying storage at a system-wide efficient scale. Thus, as with merchant investors, if storage investment is focused only on T&D benefits without capturing the benefits of wholesale power market participation, T&D utilities will similarly under-invest in storage and under-utilize storage compared to a deployment that would maximize net benefits on an ERCOT system-wide basis.

In contrast, if the full value of wholesale-market and T&D-related electricity storage can be captured, we estimate that ERCOT system-wide benefits will be greatest for a distributed storage investment level of about 5,000 MW (or 15,000 MWh), assuming that the installed storage cost decreases to about \$350/MWh. And if the cost of storage decreases further, additional investments may also be beneficial.

Deploying grid-integrated, distributed storage also raises the question “What will storage deployment do to existing generation and the investment incentives for new generation needed to maintain resource adequacy in Texas?” As we have shown earlier, if 5,000 MW of storage could be deployed by 2020, it would reduce the need for new generation by approximately 3,100 MW. Even with such reduction, a significant amount of new generation investment would still be needed. Our simulations show that, once we recognize that approximately 3,100 MW less generation would be built, the resulting wholesale market prices would still be high enough to fully support the remaining investment in new generation that is needed to maintain resource adequacy. New generating plants (as well as efficient existing plants) would earn operating margins that are nearly identical to those in a market without storage. Since the deployment of storage would yield less high-priced scarcity hours but more higher-priced non-scarcity peak hours than a system without storage, generators would earn their operating margins in a slightly more predictable fashion and over a larger number of hours in the year. Such implications may

leave generators less dependent on a few very high-priced scarcity hours, which are less predictable both in magnitude and in timing.

VI. Policies for Enabling Economic Storage Investments

Electricity storage offers benefits that span both the restructured wholesale market and the regulated T&D systems. However, under the current policy framework in Texas, neither merchant storage investors nor regulated wires companies can independently capture both streams of benefits and will therefore underinvest in this technology. This is the case because regulated wires companies are not currently allowed to own or operate assets that are offered into the ERCOT wholesale electricity market, while wholesale market participants cannot capture wires and customer reliability benefits.

We therefore review various policy options for addressing this problem and enabling storage investments in Texas. First, we briefly discuss a wide range of policy options that can be used to support storage, including options such as subsidies and mandates that would encourage investments in the technology but at a net cost to ratepayers or taxpayers. Second, we narrow our discussion by assuming that viable policy options in Texas should *not* contemplate any subsidization of the technology, but only enable cost-effective storage investments. We review a range of business models that the Texas policy makers could contemplate, and the ability for each business model to capture a portion or the full set of storage-related values. Because the economics are such that the value of storage is spread across a wide range of uses and market segments, the best policy environment is one that supports the deployment of storage on the system where most of the value streams can be captured under multiple different business models. Finally, we expand our discussion of the business model that relies on TDSP investment in storage, accompanied by third-party dispatch of those resources into the wholesale market.

We propose that Texas policy makers consider establishing a regulatory framework that will enable the state to capture the full value of deploying grid-integrated electricity storage through this and related business models. In developing a policy framework that could support the development of electricity storage in ERCOT, we identify a few objectives that must be met where possible. First, the policy framework should allow investors to maximize the value that can be captured by electricity storage. Second, the approach should maintain a clear functional separation between the regulated transmission and distribution companies' role and the competitive wholesale market suppliers' role. Most importantly, the policy should protect investment signals provided by the deregulated wholesale market from potential collateral impacts that might be introduced by regulated storage investments. Third, the policy framework should yield efficient investment decisions and not create adverse incentives for companies to over- or under-invest given the costs of the storage facilities. Considering these objectives, we separate the range of available policy frameworks into two general categories that:

- Subsidize or mandate storage investments at a net cost to taxpayers or ratepayers, or
- Remove barriers to capturing the full value to enable cost-effective storage whenever it is the most economic technology for a particular application.

The first option, to subsidize or mandate investments in electricity storage at a net cost to ratepayers or taxpayers, may take the form of direct government investment, subsidies to merchant or regulated storage developers, or through a policy mandate that directs regulated entities to invest in a certain quantity of storage, with subsidies collected from customers' charges.⁷⁹ There are many examples where a state or federal government has used direct subsidies and mandates to stimulate investments in storage or other technologies that a market-based approach has not yielded. For example, state renewable portfolio standards (RPSs) mandate that load-serving entities procure a certain fraction of their supply from renewable energy resources. Those mandates result in a payment of renewable energy credits (RECs) to renewable resources, providing revenues beyond those earned in the wholesale electricity market. For electricity storage, mandates would similarly result in additional payments from ratepayers or taxpayers to support storage investment. Depending on their policy objectives, governments also have used incentives and mandates to stimulate economic development and local employment, or to support a nascent technology such as storage. These types of policies may be quite effective at stimulating storage, but we do not view them as the best current policy choice in Texas given the unique nature of the ERCOT market structure and the state's reliance on market mechanisms as the preferred policy and regulatory approach.

The second option for a policy framework involves removing barriers that hinder the use of storage in a manner that maximizes the values captured. Such a framework would, therefore, encourage storage investment only to the extent that it is economically efficient to do so. In ERCOT, this will also require maintaining the functional separation between regulated and competitive services.⁸⁰ To achieve these goals, the policy framework must allow investors and operators to enter into contractual relationships to "share the uses" of the storage and thereby encourage the owners and users of the storage devices to reach agreements about how to maximize the value and associated revenues for the services that storage delivers to customers. Once the barriers for efficient investments are removed, we believe that ERCOT will attract substantial investments in storage if battery costs decline to the projected levels that we have analyzed in this report.

⁷⁹ As an example of a direct government investment, Duke Energy received a matching \$22 million dollar grant from the U.S. Department of Energy (DOE) as part of the 2009 stimulus program to install energy storage with its Notrees Windpower Project in Texas, funded by DOE under the American Recovery and Reinvestment Act of 2009, see Duke Energy (2009). As an example of a procurement mandate, San Diego Gas and Electric announced that they are seeking offers for at least 25 MWs of energy storage as part of California's state mandate to develop energy storage. This procurement contributes to the target of 1,325 MW of energy storage to be procured by the three investor-owned utilities by 2020, with the first procurement in March 2014 and facilities installed by the end of 2024. See Public Utility Commission of the State of California (2013) and San Diego Gas & Electric (2014).

⁸⁰ We note that policy frameworks that allow for the combination of value streams do not preclude investment in storage for the sole purpose of merchant participation in the wholesale market, or for specific T&D deferral by a TDSP, they only augment the range of business models that can be accommodated to develop storage units.

In Table 4 below, we describe the range of business models that could be considered, describing their advantages and disadvantages with respect to the amount of storage developed, customer benefits, and overall costs. In particular, we focus on the ability of each business model to capture and monetize the currently-fragmented value streams for storage. We focus on business models for in-front-of-the-meter storage that allow for direct participation in ERCOT's wholesale power markets. Significant additional policy, retail pricing, and customer incentive challenges would be associated with capturing wholesale market benefits through behind-the-meter storage devices owned by customers or retail energy service providers.⁸¹

As summarized in Table 4, a policy framework that enables capturing the fragmented value streams will need to support one of the business models that involves joint ownership or operations of the storage devices by wholesale market participant and the TDSPs. Specifically, the three joint business models include:

1. **Leaving the storage investment to merchant wholesale market participants and allowing the TDSPs to pay the merchant investors** for any values associated with reducing T&D costs or improving customer reliability;
2. **Allowing TDSPs to invest in electricity storage with regulated cost recovery and allowing them to enter into agreements with third-party entities to dispatch the storage** into wholesale markets at an arm's length from the TDSP functions; and
3. **Allowing TDSPs and wholesale market participants to jointly own storage**, such that the joint venture parties would share investment, operations, on-going costs, and the revenues received from the wholesale market or T&D customers.

⁸¹ While we do not provide a full discussion of the challenges associated with developing storage on a behind-the-meter basis, we note here a subset of the issues that would need to be addressed to enable these assets. For example, many customers, particularly smaller customers, face volumetric rather than demand-based charges for distribution costs, making it difficult to capture avoided T&D value and incurring excess distribution costs through volumetric charges, including those on the additional energy needed for round-trip efficiency losses. Retail rates generally do not reflect real-time or day-ahead wholesale market prices (except possibly for some of the largest customers), making it very difficult to capture the wholesale energy market value of storage. In addition, it is very difficult and potential infeasible to capture ancillary service value with behind-the-meter storage devices, because ancillary services must be sold directly into ERCOT's wholesale power market.

Table 4
Business Models that Enable Storage Development and Wholesale Market Participation

Business Model	Operational Control	Examples	Advantages	Disadvantages
Wholesale Market Participant Investment	Wholesale market participant	Various market participants in various RTOs have made these investments, primarily to provide ancillary services	<ul style="list-style-type: none"> • No net cost to customers • Will maximize location and storage characteristics for merchant value 	<ul style="list-style-type: none"> • Will under-build storage • Will not achieve potential reliability or T&D benefits of storage
TDSP Investment	TDSP	Allowed under FERC regulation, for example Electric Transmission Texas (ETT) installed a 4 MW battery for outage support in Presidio, Texas, see ETT (2009)	<ul style="list-style-type: none"> • No net cost to customers (if cost-benefit test is applied) • Will achieve optimal placement and deployment strategy for T&D value 	<ul style="list-style-type: none"> • Will under-build storage • Will not achieve wholesale market benefits of storage
Wholesale Market Participant Investment, with TDSP Payments for T&D Values	Wholesale market participant	New York's proposed framework would enable distribution utilities to control storage owned by third parties and compensate the resource owners, see NYS DPS (2014)	<ul style="list-style-type: none"> • No net cost to customers (if T&D values are captured by the TDSPs) 	<ul style="list-style-type: none"> • Lack of integration with T&D planning, right-of-way, and system upgrades means less likely to achieve those values • Financial disincentives for TDSP participation may undermine success
TDSP Investment, with Wholesale Market Participant Dispatch	Wholesale market participants bid usage into the market, reserving some capabilities for TDSPs	Has not yet been implemented	<ul style="list-style-type: none"> • No net cost to customers (if cost-benefit test is applied and merchant value is adequately captured and netted back to customers) • The TDSPs are in the best position to integrate distributed storage with the rest of T&D investments and operations such that the best locations are chosen to provide highest T&D system and reliability benefits 	<ul style="list-style-type: none"> • Requires regulatory safeguards to protect customers since net investment is recovered through regulated rates
Joint Venture by TDSPs and Wholesale Market Participants	Jointly operated, but bid into market by wholesale market participants	Has not yet been implemented	<ul style="list-style-type: none"> • Theoretically can capture all benefits and support optimal quantity 	<ul style="list-style-type: none"> • Less financial incentive for TDSP to plan and deploy storage • Joint venture may be less transparent than auction or competitive bidding process

While each of these three joint business models has its own advantages and disadvantages, we will more fully discuss the second option of TDSP deployment with third-party dispatch. We believe that this is an attractive business model for deploying grid-integrated storage and reducing barriers to capturing the full set of storage-related values in ERCOT. This policy framework would allow TDSPs to:

1. Make the storage investments based on Commission-approved deployment plans;
2. Rate base the investments for regulated cost recovery;
3. Integrate the storage deployment with the TDSP's transmission and distribution planning activities;
4. Operate storage to improve grid reliability and avoid customer outages;
5. Auction off the market dispatch to third-party wholesale market participants who would schedule the charging and discharging of the storage devices to maximize revenues from the wholesale market; and
6. Credit back the auction proceeds to ratepayers to reduce the regulated rates that the TDSPs' retail customers pay for the storage investments.

Under this policy framework, the TDSPs would continue to be involved only in transmission and distribution services without direct wholesale market participation. Third-party wholesale market participants who obtained market dispatch rights would need to accept certain restrictions on their dispatch into the wholesale market before entering into these contracts (*e.g.*, by agreeing to fully charge the batteries at times when major storms are forecasted and distribution outages anticipated).⁸²

One significant advantage of allowing TDSPs to invest in storage is that they are in the best position to identify, deploy, and operationally integrate storage in the most beneficial locations within the distribution system, thereby capturing the most value from transmission and distribution cost deferrals and improved customer reliability. TDSPs also have access to existing distribution system rights-of-way for the placement of the storage devices and can leverage their

⁸² Even though at times, the use of the storage to avoid customers' power outages may be in conflict with maximizing the value the storage can obtain from the wholesale markets, we anticipate those times would be infrequent because the most foreseeable outages occur with forecast storm events that do not typically occur during times of peak electricity demand. Thus, batteries can be charged up and held at full charge before an anticipated storm event. At the same time, it is important to avoid constraints on wholesale market operations that reduce the wholesale market value of the storage devices by more than the incremental reliability and T&D benefits provided by the operational constraints. These potentially conflicting uses must also be accounted for in cost-benefit analyses to make sure the aggregate benefits are simultaneously achievable. For example, in this study, recognizing that the storage devices would go through a full charge and discharge cycle on an almost daily basis (and considering the fact that the devices are near but not within customer premises), we assumed that only approximately 50% of the full reliability value would be captured.

existing operations and maintenance infrastructure to operate and maintain the devices. But in evaluating this business model and the benefit-cost analysis in each individual storage deployment plan, Texas policy makers will need to weigh the tradeoff between: (1) the advantage of allowing the TDSPs to own the storage devices and optimize the deployment based on T&D and reliability benefits; and (2) the potential risks associated with allowing TDSPs to recover the investment costs associated with storage deployment from ratepayers.

We believe that the advantages of grid-integrated storage owned by TDSPs exceed its risks if appropriate regulatory safeguards and market mechanism are implemented. Risks can be mitigated, for example, through a regulatory process that ensures that TDSP storage investments are made gradually with deployment plans evaluated and approved by the Texas Public Utilities Commission. The deployment plans would include assessing the expected value proposition for each round of investments. The experience gained in (smaller) earlier rounds of investment could then inform the value proposition of the subsequent (larger) tranches of investments.

We envision a regulatory process that would allow TDSPs to make the investment in electricity storage and recover the associated investment costs through regulated rates as long as: (a) a significant fraction of the value of these storage assets is associated with transmission and distribution system benefits that are not captured through wholesale market participation; (b) it is shown that the incremental system-wide benefits are expected to exceed costs by a sufficient margin; and (c) the aggregate TDSP storage investments are sufficiently limited in scale and phased-in over time such that they would not create excess supply conditions in the ERCOT wholesale market or eliminate the need for new generation investments. In addition, regulations would be needed to maintain a clear delineation between the storage-related functions of the regulated TDSPs and those of the wholesale market participants.

While the detailed design remains to be developed, we believe that this proposed regulatory framework has substantial promise for a deployment of grid-integrated storage. The benefits of storage associated with improved system reliability, deferred transmission and distribution investments, and participation in ERCOT's wholesale energy and ancillary services markets could all be captured simultaneously while aligning market participants' and customers' interests with those of the T&D utilities making the storage investments. This approach could resolve the barriers created by fragmented value streams that will otherwise lead to under-investment in electric energy storage in Texas.

While we have provided a sketch of this policy framework, we also acknowledge a number of important components that have not yet been designed or evaluated comprehensively. Areas that we have not addressed in this report include:

1. We have not developed an actionable deployment plan. We envision that realistic deployment plans would involve a phased-in approach during which the cost-effectiveness could be proven based on actual experience with the necessary operational, regulatory, contractual, and financial arrangements. We also anticipate that the regulatory process could allow for a phase of "learning by doing" before larger-scale deployment and financial commitments are approved.

2. We have not developed the parameters of the auction design, the detailed regulatory framework, or the specific safeguards that would be needed to operationally and financially unbundle the regulatory and competitive market functions of the storage devices in ERCOT's market structure. Some of the parameters that would need to be developed include:
 - a. The scope and process for regulatory approvals;
 - b. The specific roles of TDSPs and other market participants in asset ownership and operations;
 - c. The terms and durations of the contracts between the TDSP and third-party market participants;
 - d. The structure of the auction or procurement process that could be used to financially unbundle regulated and competitive uses; and
 - e. The allocation and regulatory treatment of auction proceeds (as a revenue credit or ratebase offset, an up-front or annual payment, *etc.*).
3. We also have not specified the optimal operational limits that would need to be imposed on charging and discharging cycles to make it possible to obtain a sizable portion of the evaluated transmission, distribution, and reliability benefits, while also allowing the storage devices to participate in ERCOT's energy and ancillary services markets to maximize the overall value of deploying grid-integrated storage.

To move beyond the conceptual regulatory framework outlined in this report, these three areas should be considered in developing a regulatory roadmap for Texas. In addition, we suggest that policy makers, regulators, and market participants engage in a dialogue to carefully consider this policy and regulatory framework, along with other potential electricity storage business models described above. Further, careful evaluation of the advantages and disadvantages of each proposed business model would help all involved in developing a robust approach for Texas to maximize the benefits of grid-integrated electricity storage.

List of Acronyms

ATWACC	After-Tax Weighted-Average Cost of Capital
CAISO	California Independent System Operator
CC	Combined-Cycle
CDR	Capacity Demand and Reserves
C/I	Commercial and Industrial
CIM	Customer Interruption Minutes
CO ₂	Carbon Dioxide
CONE	Cost of New Entry
CP	Coincident Peak
CPUC	California Public Utilities Commission
DOE	Department of Energy
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GRR	Generator Revenue Reduction
GWh	Gigawatt Hour
ISO	Independent System Operator
kVA	Kilo Volt Amp (1,000 Volt Amp)
kWh	Kilowatt-hour
LIPA	Long Island Power Authority
MISO	Midcontinent Independent System Operator
mmBtu	One Million British Thermal Units
MW	Megawatt
MWh	Megawatt-hour
NaS	Sodium-Sulfur
NPV	Net Present Value
NYISO	New York Independent System Operator

O&M	Operations and Maintenance
ORDC	Operating Reserve Demand Curve
PCS	Production Cost Savings
PJM	PJM Interconnection
PSO	Polaris Systems Optimization
PUCT	Public Utility Commission of Texas
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standard
SAIDI	System Average Interruption Duration Index
SCE	Southern California Edison
T&D	Transmission and Distribution
TDSP	Transmission and Distribution Service Provider
VOLL	Value of Lost Load
VOM	Variable Operations and Maintenance
WA	Washington

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