# Exploring Natural Gas and Renewables in ERCOT, Part III:

## The Role of Demand Response, Energy Efficiency, and Combined Heat & Power

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# I. Introduction and Summary

## A. INTRODUCTION

In December 2013 we completed a series of simulations of the future of the ERCOT electricity marketplace through 2032 on behalf of the Texas Clean Energy Coalition (TCEC). The goal of these simulations was to show how renewable and natural gas-fired electricity sources would develop in the next two decades, and how this development would depend on gas prices, the existence of a capacity mechanism in ERCOT, national carbon policies, and other key market drivers. We found a wide range of 2032 outcomes, from scenarios with over 40% of ERCOT's 2032 energy coming from renewables to other cases in which nearly all future capacity additions would be gas-fired.[1]

In order to simulate the future ERCOT grid we relied primarily on ERCOT's own long-term planning and operating data, supplemented by selected additional items from our research. In the areas of electric power demand and sales, the role of demand response and energy efficiency, and the role of distributed sources of generation, we relied almost entirely on ERCOT's base case forecasts and no sensitivity analysis. In short, our simulations were focused primarily on exercising the large-scale supply side of the marketplace under "reference case" demand-side assumptions.

In this report we expand our prior work to incorporate a more extensive set of demand-side scenarios. These scenarios, most of which would require state policy and/or market changes, provide a more complete answer to our original motivating question, *i.e.,* what are the possible range of outcomes for the full set of electricity resource options in the future Texas power grid? What are the drivers of these futures, and how much impact do they have on electricity prices, greenhouse gas emissions, and other important factors? How much of the future depends on policy choices versus the inexorable tide of market forces?

Our new work employs an updated version of the unique modeling system employed in our 2013 work. This system -- described in more detail below -- combines a model that simulates the decisions of market-driven developers of a wide range of new electric resources with a model that simulates the minute-by-minute operation and control of the grid by ERCOT. By combining these two perspectives, our modeling system finds future trajectories that represent, for any given scenario, a realistic set of resources the market is willing to build and that can be integrated and managed by ERCOT to yield adequate and reliable power service.

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[1] Drs. Ira Shavel, Jurgen Weiss and Peter Fox-Penner, "Exploring Natural Gas and Renewables in ERCOT: Part II: Future Generation Scenarios for Texas", The Brattle Group December 10, 2013. http://www.texascleanenergy.org/TCEC_Report%20Final%20Clean%2012%203%2013.pdf.

## B. SCENARIOS AND RESULTS

Our new results are drawn from a revised set of scenarios involving both key supply and demand-side drivers. The four scenarios we examine are:

- **Phase III Reference.** A new Reference case, with updated forecasted power sales and base case gas prices, as well as added CHP potential and **a refined and** expanded portfolio of DR programs;
- **Enhanced Energy Efficiency.** The Phase III Reference case with an added portfolio of cost-effective energy efficiency programs;
- **Moderate Federal Carbon Policy.** The Enhanced Energy Efficiency case with an added requirement that all coal-fired facilities capture and sequester 50% of their $CO_2$ by 2025; and
- **Strong Federal Carbon Policy.** The Enhanced Energy Efficiency Case, but with (a) a rule that all coal-fired plants sequester 90% of their $CO_2$ by 2025; (b) higher natural gas prices due to increased gas demand to replace coal units that cannot cost-effectively sequester 90%; and (c) lower renewable energy costs from more rapid deployment.

Table I-1 summarizes the differences of these four scenarios.

### Table I-1 Overview of Modeled Scenarios

| No. | Case* | Gas Price | Renewable Cost | Load forecast | Carbon Policy |
|-----|-------|-----------|----------------|---------------|---------------|
| 1 | Phase III Reference | AEO 2014 Reference | Base | Brattle Phase III forecast | No |
| 2 | Enhanced Energy Efficiency | AEO 2014 Reference | Base | Brattle Phase III forecast adjusted with enhanced EE portfolio | No |
| 3 | Moderate Federal Carbon Policy | AEO 2014 Reference | Base | Brattle Phase III forecast adjusted with enhanced EE portfolio | In 2025 coal units require 50% carbon reduction |
| 4 | Strong Federal Carbon Policy | AEO 2014 Low Oil and Gas Resource Case | Approx. 15% reduction in capital cost by 2025 | Brattle Phase III forecast adjusted with enhanced EE portfolio | In 2025 coal units require 90% carbon reduction |

*All cases include existing DR programs, new DR programs, and CHPs as resource options 
 All cases don't model reserve margin requirement.*

The highlights of our findings include these results:

- Across all Phase III scenarios, natural gas and renewable additions dominate the supply picture, with gas providing both low-cost baseload energy and ancillary services that integrate wind and solar energy. The original forms of complementarity we have discussed in prior reports for the TCEC continue to occur, albeit in a more nuanced manner with the introduction of the increased options of EE, DR, and CHP.

- New large CHP installations at petrochemical facilities are very economical and the simulation indicates that the full potential of these opportunities will be realized by 2032 in all scenarios. However, the high capital costs and rapid required payback required of smaller CHP units prevent any further CHP adoptions in our scenarios.

- Energy efficiency and demand response provide substantial opportunities to displace future capacity additions and lower overall electricity costs. Our program portfolio was designed to be moderate in size and use well-established approaches primarily driven by ERCOT energy prices. Nonetheless, 3 GW of new EE programs and around 2-4 GW of new DR programs are identified as economically achievable in ERCOT in our modeling scenarios. In total, this represents a 40% to 50% reduction in projected peak demand growth (depending on the carbon policy scenario).

- Real energy prices in Reference scenarios remain within the band of prices actually experienced in ERCOT between 2010 and 2012. The highest annual average price for a converged year is about $67/MWh ($2012) for the Strong Federal Carbon Policy scenario, which has higher gas prices. However, even this extreme scenario price is $3/MWh lower than its counterpart scenario in Phase II.

- Carbon emissions are slightly below all comparable Phase II scenarios. These lower emissions are due to reduced sales (including from EE programs) and higher renewables penetration.

## C. IMPORTANT STUDY CONSIDERATIONS

As in the prior phase of this research, we emphasize that these results are not intended to be our definitive prediction of the most likely future path for the Texas power marketplace nor our explicit policy recommendations. Instead, our goal is to illustrate the relative effect of important drivers, determine whether renewables and gas are likely to be complementary or competing, and explore the effects of a limited set of policy directions. Among other limitations, the set of generation resources, Demand Response (DR) options, and Energy Efficiency (EE) programs we include in our modeling system is by no means intended to be exhaustive. There are unquestionably other options that we could not include in our scenarios that will play a role in Texas' energy future, whether in the form of new demand response options, new low-carbon generation technologies, or expanded forms of traditional power.

There are also important limitations and assumptions in this study that should be noted. First, we do not assume major technical breakthroughs in new energy technologies such as electricity storage, small nuclear reactors, or carbon capture and sequestration. Second, even drawing from the current and forecasted set of technologies we do not include every current option. For example, concentrating solar power plants are now in use in the Southwestern United States, but we do not include them as a resource option simply due to budget limitation. Third, our solar Photovoltaics (PV) resource option should be viewed as utility-scale solar, as we do not include state or federal policy changes that would accelerate distributed solar in Texas. Fourth, our model reflects much but not all of time variability of solar and wind power, thus slightly understating the integration resources needed for these additions. Finally, our modeling system does not formally incorporate risk aversion and fuel price uncertainty, which would reduce gas investment relative to wind, solar, and coal-fired options. These considerations are discussed further in the introduction to our Phase II study.

### D. GUIDE TO THIS REPORT

This report is organized into seven Chapters. The next chapter describes our modeling system with particular detail on how we model DR, EE, and CHP in this phase. Following this, Chapter Three describes our updated general data inputs. Chapters Four, Five, and Six describe our development of demand response, energy efficiency, and combined heat and power (CHP) resource input options. Each of these chapters contains a detailed discussion our data sources, analyses, and conclusions employed in our model runs. Chapter Seven presents our results and conclusions.

## II. Modeling the Future ERCOT System: Conceptual Overview[2]

As noted, the project's goal is to simulate, as accurately as possible, the interaction between renewable and gas generators on the ERCOT system through 2032.  More concretely, this means estimating the amount of power plant capacity by type (gas, solar, wind, coal, etc.) that is either added or retired within ERCOT over the study period, and the amount of new DR, EE, and combined heat and power (CHP) that is added as well.  Since capacity additions in ERCOT are primarily driven by competitive forces that yield the prices earned by generators, our challenge is to simulate the behavior of a multitude of competitive generation developers active across the potentially viable fuel and technology options.  At the same time, we assume that ERCOT continues to be responsible for ensuring that its grid operates reliably and in conformance with NERC standards.

The real-world interaction between the price-deregulated generation market and ERCOT's grid management responsibilities is exceedingly complex, especially over a study period spanning twenty years.  The interaction can be abstracted into a repeated series of cycles of the expansion of the ERCOT system.  Each cycle can be thought of as the period over which generation developers, industrial facilities that might host CHP, and load aggregators (broadly referred to as "developers" in this report) look at the current market and decide the next group of plants they are going to build or retire.  The system responds by adding new transmission lines (if needed) and ERCOT adjusts its operations to accommodate the new plants, retiring units, and new load growth.

The cycle can be further disaggregated into a series of steps explained as follows:

### A. Simplified Steps in the ERCOT Expansion Cycle

- At the start of the cycle all the generators, DR programs, EE programs and transmission system are existing facilities and programs.  ERCOT conducts the market processes and all other operating procedures that together yield hourly and sub-hourly prices for all market products and also ensure reliability is maintained.

- Developers look at power market prices and form their own predictions as to how these prices will change in the coming twenty years  (since most new plant investments last twenty years or more, a developer typically forecasts over this period).  This incorporates the developers' own predictions of how fuel and

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[2]  For other considerations of our modeling methodology, including modeling the impacts of wind and solar variability and uncertainty and the impact of fuel price uncertainty and quantity risk, please refer to our Phase II Report, Exploring Natural Gas and Renewables in ERCOT: Part II: Future Generation Scenarios for Texas, December 10 2013, http://www.texascleanenergy.org/TCEC_Report%20Final%20Clean%2012%203%2013.pdf.

technology costs will change, how ERCOT market rules will change and their effect on prices, how environmental or tax rules might change, and other factors that influence their predicted revenues. Note that there is substantial uncertainty around many of these factors, yielding a highly uncertain future revenue prediction that is usually reduced to an expected value and either some "high" and "low" cases or a formal analysis of the impact of uncertainty.

- Based on these predictions and uncertainties, developers indicate to ERCOT that they plan to add their chosen amount and type of new resources at their chosen location.

- ERCOT uses developers' indications of future resources to run simulations of the operation of its power system with these new resources. These simulations indicate to ERCOT where new transmission lines or other facilities to ensure reliable service are needed. Other simulations tell ERCOT whether it must change its operating procedures to ensure reliability. For example, when additional wind is added to the system in a future year, there is more variability in generation from all wind resources than in prior years. This might prompt ERCOT to change its procedures to purchase larger amounts of ancillary services (AS) and/or change the rules in the AS markets. These changes are complex, but could have substantial impacts on the revenues earned by generators who sell ancillary services. Thus, ERCOT's changes to its procedures may result in subsequent significant changes in predicted market price outcomes for many future years.

- It is worth noting that some of the simulations ERCOT conducts in response to developers' announced plans, and some of the changes they implement that affect market prices, don't occur far in advance of the new additions being added. This is due in part to the fact that as market outcomes evolve, the regulatory process may cause ERCOT to determine that new transmission is needed or adjust operation actions. Thus, the best way for developers to understand the full impact of all of ERCOT's adaptive responses to the most recent round of additions is to observe market price outcomes once the new resources have been added to the grid and ERCOT has adapted.

- Developers' observations of the new market price and revenue outcomes give them an updated basis for looking forward to their next cycle of competitive additions. If their private forecasts predict that they can profitably build and operate one particular type of power plant over its economic life they will probably try to build it; conversely if it will not remain economic they will stay out of the market.

In reality, the expansion cycle in ERCOT and all other markets occurs in several overlapping time frames that span two to three years, not a discrete series of sequential steps. For modeling purposes, however, we abstract the cycle into two concurrent activities, each of which can be

modeled as if a full cycle takes one year. These steps are illustrated in flow-chart fashion in Figure II-1 and explained as follows.

### Figure II-1: Simplified Annual Cycle of ERCOT System Expansion
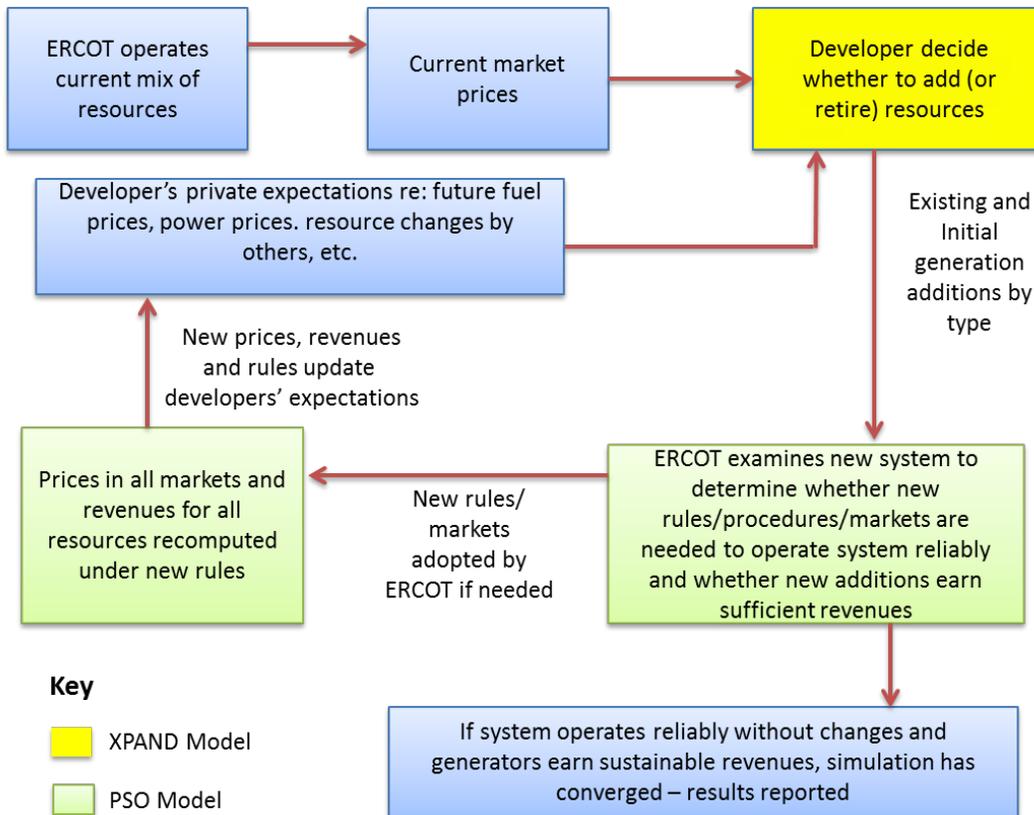
The first of these activities are market participants' annual choices of generator additions and retirements by location and type as well as DR/EE programs. We use a model known as Xpand to simulate the totality of the market's resource decisions in each year. Xpand's underlying logic mimics the market-price-driven decisions of developers. Specifically, for a list of new resource options, Xpand examines the cost of building and operating the plant over its prospective life span, and the cost of DR/EE programs with the energy and capacity need reductions with the current and predicted future revenues each resource will earn or avoid. (The plant options, including DR, are discussed in Section III). In any annual cycle, Xpand adds ("builds") all resources for which the forecasted present value of revenues equals or exceeds present value capital and operating costs over the economic life of the resource. Xpand also checks the

profitability of all existing plants and retires any plant whose future predicted revenues do not cover the sum of its future operating costs and required capital outlays.[3]

Although resources are often acquired under long-term contracts, Xpand assumes that all generation resources earn revenues equivalent to the spot prices for energy and ancillary services, and DR/EE avoid costs that are greater than program costs. The respective prices are the result of supply and demand bids in the spot markets operated continuously by ERCOT. Xpand contains a simplified market price calculator that balances total supply (existing plus new resources) with each year's demand. However, these prices are modified by the second half of the simulation system, the Power Systems Optimizer (PSO) model.

PSO is a model that simulates the operation of ERCOT's reliability maintenance and market operations on a very detailed basis. When given a level of momentary power demand within ERCOT, forecasted levels of wind and solar energy, a set of new and existing ERCOT power plants, and new and existing DR/EE resources, the model simulates ERCOT's dispatch of all plants and its market-clearing prices in all markets for each intra-hour period[4] within each annual cycle.

These detailed simulations are used to check and modify Xpand's annual generation additions and retirements. In effect, PSO asks "How well can I operate the system reliably if I add all the generators that Xpand thinks are profitable to add? If I can't operate reliably, what must I do to make the system reliable? When I finish taking actions to make the system operate reliably, what are the resulting series of spot prices in all the markets I operate, and do the various resources on the system earn enough to justify continued operation?"

PSO provides simulation results that allow the modeler to study these questions and experiment with modifications that eliminate any observed reliability problems and reduce system inefficiencies. To use one purely illustrative example, Xpand may have found that 1,000 MW of additional solar resources may be profitable to install in a future year. PSO then may identify problems with maintaining reliability with this level of new solar installations because there is not enough capacity in the system to ramp up with sufficient speed to protect against a blackout at the end of the day when solar output declines rapidly just as residential air conditioning load surges. By examining the PSO results and determining why the reliability criteria are violated, we judiciously alter the need for reserves, either by increasing an existing reserve requirement or perhaps even creating a new type of reserve, which in turn impact the mix of new capacity added by Xpand in a second iteration. For example, we might add an additional 150 MW of fast-ramping combustion turbines and find that this corrected all reliability problems.

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[3]  Xpand employs expected value prices over the forecast horizon and therefore does not explicitly account for the impact of price uncertainty on investment decisions. We discuss the impact of uncertainty further in Section III.

[4]  In this study, the intra-hour period duration used is 10 minutes.

If the 150 MW of combustion turbines noted above were not added originally by Xpand, it was because they were less profitable than the other additions found by Xpand at the prices forecasted by Xpand in the absence of combustion turbines. However, if combustion turbines are required to preserve reliability, both models are instructed to require that they be built. Once this occurs, both models will forecast different future price paths, since the set of generators bidding into the markets now includes the new required natural gas combustion turbines (CTs).

Each model is then re-solved to determine the most profitable set of system resource additions in light of the new prices and presence of the CTs. Xpand's decisions to add and retire plants, once required to include the new reserve requirement, could change significantly. Again for illustration, Xpand may find that the presence of the CTs may have reduced the market-clearing energy spot price during the peak periods of the day for years to come. This could reduce the profitability of some of the solar additions, since they tend to generate power during the midday peak period. Thus, Xpand may now determine that only 500 MW of solar is now profitable.

In theory, the addition of the CTs following the addition of solar plants could also yield another quite different result. The combination of new CTs and new solar could lower energy prices to the point where coal-fired power plants (which must also install new pollution control devices) are no longer profitable to operate. This can occur because these plants are generally expensive to start up and shut down but are also not profitable to operate continuously at the new lower level of prices. When this occurs, Xpand would make the decision to retire these units. This is the kind of interaction between longer and shorter term market dynamics that guided our choice of modeling infrastructure.

The overall process of running PSO, modifying the ERCOT system to ensure reliability, recalculating prices, re-choosing resource additions, and re-checking the simulated system dispatch, prices and energy margins (profits) to ensure reliable operations is illustrated in Figure II-1. We refer to this overall process as *converging* the two models and the final result as a converged simulation of future grid additions and prices. This converged solution mimics the ultimate outcome of the true cyclical interaction of ERCOT and its generation market in the presence of reliability requirements.

Although Xpand computes resource changes for every year of the study period, for the purposes of our analysis it is not practical to run PSO and converge the two models for every year of the study period. Instead, for each of the scenarios we converge the two models by running PSO for the years 2017, 2022, and 2032 and comparing the results of Xpand and PSO in these three years. The results of each converged year are fed forward into the next convergence cycle. For each scenario, the final result is an evolution of system additions and retirements found to be most profitable, given forecasted prices and policies, consistent with reliable system operation – the conceptual equivalent of the outcomes of the competitive market managed by ERCOT should yield over time.

With respect to transmission costs, it should be noted that our modeling system does include many important transmission limits in the current ERCOT grid, but does not ascribe differences in transmission costs between any generation options.[5] In other words, to the extent generation additions require new transmission, this expansion does not influence generators' decisions. Similarly, with the exception of one possible increase in Competitive Renewable Energy Zones (CREZ) capacity, we do not add or subtract any new transmission constraints. One final implication of this treatment is that the additional cost of new transmission lines is not calculated. While all of these assumptions are simplifications, we believe they are reasonable in the context of this analysis.

## B. MODELING EE AND DR

In our Phase II analysis, we modeled DR but we did not model EE. For that analysis we followed ERCOT's lead. We had two types of DR that were available in each year, a block of commercial DR and a block of industrial DR, each of which had a strike price in terms of dollars per megawatt hour, and a minimum and maximum number of hours per year that they could be called. We modeled both existing DR as well as potential future DR in this fashion.

For this report we have conducted a detailed assessment of the existing DR programs in ERCOT and of potential new DR programs in ERCOT, by sector. For the existing programs we modeled: (1) the transmission and distribution service providers' current load management programs; (2) ERCOT's Emergency Response Service program; (3) ERCOT's Load Resources program; and (4) municipal utility Direct Load Control programs. These programs are available throughout the model horizon and can reduce peak load up to approximately 2,550 megawatts.

The new DR programs we have modeled are: (1) air-conditioning direct load control for residential and small commercial and industrial customers; (2) interruptible tariffs for medium and large commercial and industrial customers; and (3) dynamic pricing for all customer classes. The potential annual market penetration of these programs grows over time. A key difference between these new program options and the existing ERCOT programs is that the new programs are dispatched based on economics (e.g., to avoid high energy market prices) rather than purely in response to system emergencies.

Most programs have a limit on the number of hours that customers can be curtailed and, in some cases, the months during which curtailment can occur. The only program that does not have a limit on number of hours is the non-controllable load resource program. This is a program that ERCOT uses at times of market scarcity to provide responsive reserves. Customers that are signed up for the service have under frequency relays installed to ensure that they respond when needed.

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[5]   See Appendix B in our Phase II report for further details on the transmission constraints modeled in PSO.

We model the economic decision to invest in new DR programs assuming a program cost that is a one-time upfront cost and an annual ongoing cost. For example, the residential air-conditioning direct load control program has a one-time cost for the purchase and installation of the control equipment as well as an annual participation incentive payment.

In the Xpand model, we are able to limit the number of hours that a DR program is called annually. In the PSO model we cannot impose a direct limit. Part of our convergence process was to make sure that the demand response programs were utilized in a way that is consistent across the models and is within the specified parameters. Since most DR programs do not have a variable cost, PSO would overuse them unless an appropriate price was provided for dispatching of these programs. To tie the Xpand and PSO results together, we calculated a "shadow price" in Xpand that we instituted in PSO's dispatch. This shadow price was initially estimated as the price during the hours of operation of the DR program in Xpand.

EE was modeled as a modification to the overall load shape over time. We modeled both existing EE programs as well as potential future EE programs. Since ERCOT's load forecast assumes "frozen efficiency" it was necessary to first modify the forecast to account for known/planned efficiency improvements. For example, while Texas law requires that the Transmission and Distribution Service Providers (TDSPs) meet certain energy efficiency goals, we understand that the future impact of achieving these goals is not included in ERCOT's load forecast. In addition to the programs that are already in place, there are certain federal standards that will continue to increase overall efficiency over the next 5 to 10 years. These standards are also not included in the ERCOT load forecast. We adjusted ERCOT's load forecast to account for both of these types of factors. That was the starting point for our Phase III load forecast.

We then consider a range of future energy efficiency programs and evaluate their cost-effectiveness. Programs we identified as low-cost programs with significant potential for energy efficiency improvement in Texas are: (1) residential cooling efficiency; (2) commercial indoor lighting efficiency; and (3) industrial pump efficiency.

We estimated the potential of these programs and incorporated them as reductions to the load forecast over time. We verified that the programs more cost-effective by calculating a benefit-cost ratio for each program using modeled prices.

## C. MODELING CHP RESOURCES

Texas has a large industrial base, which, among other factors, has resulted in it having the largest installed base of CHP of any state. Most of the CHP capacity is in the chemicals and petroleum industries, which provide opportunities for large facilities that take advantage of economies of scale. Since previous research concluded that there are limited opportunities for CHP outside the industrial sector, we focused our analysis on additional opportunities in the industrial sector.

We assumed that CHP plants would be sized to best match the thermal load of the industrial host facility. It is possible to oversize the electric generation portion of a CHP facility, but that

reduces the overall efficiency of the project. We limited our analysis on industrial applications with sufficient thermal load to require CHP capacity in excess of 1 MW CHP, since the economics of very small facilities is much weaker than for larger facilities.

We evaluated the CHP potential for existing industrial facilities as well as for future new industrial facilities based on the industrial growth rates forecast in the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2014 for the petrochemical industry and Texas' historical growth rates for other industrial sectors.

CHP can be cost-effective because it replaces a source of thermal energy (typically a boiler) and electric generation from a conventional generation source with a single facility that provides both. The result is a facility that at a large-scale can be similar to a 300-600 MW modern combined cycle, but has a heat rate that is considerably lower. That lower heat rate is a function of the overall efficiency of the cogeneration process.

While Texas, and ERCOT in particular, already has a very large base of CHP facilities there are still opportunities. Many of the larger industrial facilities such as refineries and chemical plants already have CHP. This is less true at smaller facilities, which do not provide the same overall economies of scale as larger facilities.

There are a number of barriers to development of CHP facilities, and these barriers are economically more burdensome at smaller facilities. These barriers include: 1) the need for the industrial facility to not only be in the business of its own industry, but also get into the electricity business; and 2) the additional complexity of the overall facility. Many of the larger installations around the country that have CHP were projects developed by merchant generators. The merchant sees an opportunity to build an electric generator that has a much lower heat rate than competing facilities. The merchant would think of the facility very much like an investment in a standalone combined cycle plants, with additional contracts for thermal offtake to support the host industrial facility.

In our analysis we assumed that the large facilities of this type would be built by merchants and would be financed in essentially the same way as our merchant combined cycle plants. Smaller thermal loads can only support smaller facilities. While the overall efficiency to produce electricity at small facilities is still much better than a standalone combined cycle plant or a simple cycle plant, the capital cost is much higher and the institutional burden for all parties becomes greater.

For these reasons, we model the largest CHP opportunities in much the same way we model combined cycle plants, with the same basic financing arrangements and payback period. For smaller facilities we relied on an analysis by Primen of market acceptance of distributed generation technologies to reflect the greater barriers facing with smaller facilities.[6] Figure II-2

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[6] Combined Heat and Power: Policy Analysis and Market Assessment: 2011-2030, ICF.

shows the Primen curves for strong, soft, and non-prospects based on their self-reported attributes towards adoption of distributed energy, along with our straight line estimate of their acceptance.

### Figure II-2 Market Acceptance of Different Payback Periods by Customer Interest in CHP

We modeled the decision to add the smaller sizes of CHP plants in the following way:

- We started by limiting the maximum capacity for smaller CHP facilities available for Xpand to economically choose based on the technical potential for a given year and the adoption rate curve at a six year payback.

- If CHP facilities were added with a six year payback, we added that capacity to Xpand model and ran again with additional capacity available at with a shorter payback period.

- We stopped when new capacity was no longer economic.

- We then moved forward in time and performed the same analysis the future years.

# III. Discussion of Key Inputs Update and Scenarios

As in Phase II, the majority of data and assumptions for our models are taken directly from the most recent comparable ERCOT planning efforts, supplemented in some cases by U.S. Department of Energy (DOE) data and forecasts. This section explains our derivation of most of the key study inputs that we developed that are distinct from ERCOT or DOE data. With the exception of our assumptions on energy efficiency, demand response, CHP, forecasted sales, and natural gas prices, our assumptions and data are largely the same as those employed in our Phase II report. Due the extensive analysis we devoted to EE, DR, and CHP assumptions in this phase we describe these data in the next two chapters following.

## A. LOAD FORECAST

We adjusted the peak demand and energy forecasts from our Phase II study in two ways. First, we updated the forecasts to be consistent with new ERCOT projections. ERCOT substantially revised its forecasting methodology in March 2014 in an effort to reduce forecasting error, and it was essential to capture the effects of these changes in our study.

Our second adjustment was to modify the new ERCOT projection to account for known/planned future efficiency improvements that will occur over the forecast horizon. Importantly, ERCOT's forecast represents a "frozen efficiency" case. According to ERCOT:

> "…the forecast model employs statistical techniques that unyieldingly fix the relationships between load, weather, and economics at their 2013 state. Such an assumption has significant implications. Among other things, it means that the thermal characteristics of the housing stock and the characteristics of the mix of appliances will remain fixed. If thirty percent of the residential central air conditioners in the South Central weather zone have Seasonal Energy Efficiency Ratios (SEER—a measure of heat extraction efficiency) of 12 in 2013, then the model assumes the same proportion in all forecasted years."[7]

To establish the appropriate baseline for our study, which is focused specifically on demand-side developments, it was necessary to account for known factors that will drive future efficiency improvements. One such factor are codes and standards that have already been put in place, but the full effects of which have not yet been observed. For example, the Energy Independence and Security Act (EISA) of 2007 establishes, among many things, minimum household lighting standards that began in 2012 and will further increase in 2020. These impacts will certainly reduce residential lighting electricity consumption in the future. Similarly, growth in TDSP Demand Side Management (DSM) programs is likely to persist in the future, as mandated by

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[7] ERCOT, "2014 ERCOT Planning Long-Term Hourly Peak Demand and Energy Forecast," March 31, 2014, p. 16.

Texas state law. An emerging trend in customer preferences for more energy efficient technologies will lead to further sales reductions.[8]

We have also relied in part on the EIA's sales forecast in its 2014 AEO to account for these factors. In its demand forecasting module, the EIA explicitly accounts for the future impacts of established codes and standards, and also accounts factors such as expected future reductions in the costs of energy efficient technologies and trends in consumer preferences. Between 2014 and 2024, EIA's projected annual growth in sales for the ERCOT region is 1.1 percent, whereas ERCOT's "frozen efficiency" projection growth rate is 1.3 percent.

To account for the known efficiency improvements, but to avoid potentially overstating their impact, we started with ERCOT's energy projection for 2014 and conservatively grew this value annually at the <u>average</u> of the growth rate in the EIA and ERCOT projections in each year.[9] To establish our modified peak demand forecast, we maintained the same annual load factor that is implied in the ERCOT forecast.[10] Our final adjusted energy and peak demand forecasts are shown in Figure III-1 and Figure III-2, respectively. In both figures, we have included the forecast from our Phase II study for reference.

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[8] A Brattle whitepaper on this topic is forthcoming. Naturally occurring energy efficiency – also known as organic conservation – is often quantified in DSM potential studies and observed as free-ridership in utility DSM measurement & verification studies.

[9] The ERCOT forecast was extrapolated to 2032 so that we could establish a forecast for our full modeling horizon.

[10] Load factor captures the relationship between peak and energy. It is expressed as average demand divided by peak demand. ERCOT projects an increasing load factor, meaning that energy will grow more quickly than peak demand.

## Figure III-1: ERCOT Energy Forecast
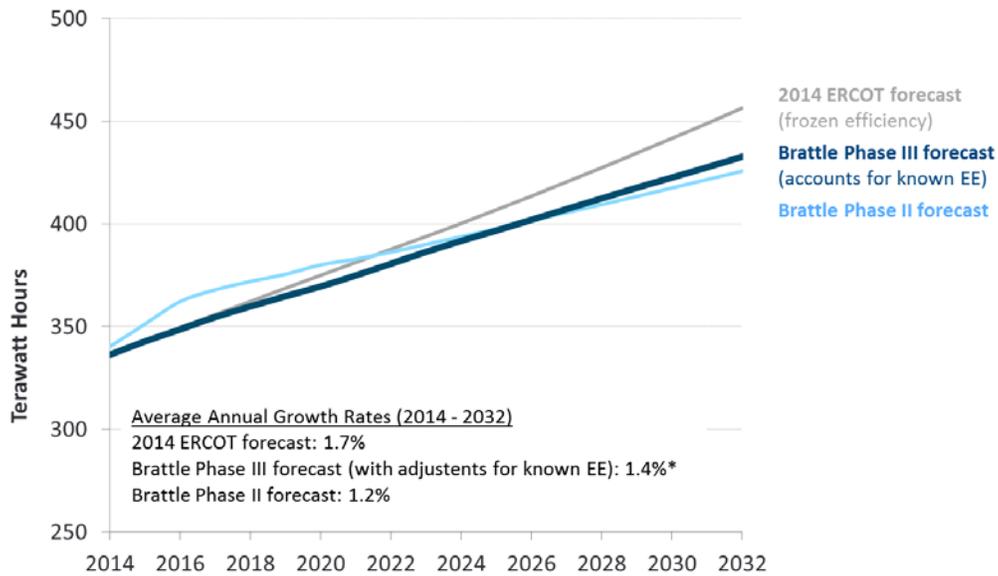


Sources and notes:
2014 Annual Energy Outlook Table 73 and 2014 ERCOT Long Term Hourly Peak Demand and Energy Forecast
* Since ERCOT 2013 forecast for 2013-2022 showed different growth rates before and after 2016, Brattle Phase II forecast applied the last 5 year's
average annual growth rate (2017-2022) to derive the forecast in 2023-2032, resulting in an average growth rate of 1.4% in 2014-2032, lower
than the average growth rate of 1.7% during ERCOT forecasted horizon 2013-2022

Relative to the Phase II energy forecast, our new energy forecast is lower in the early years of the forecast horizon, but slightly higher by 2032. It is notable that, after accounting for known efficiency, our new forecast is higher than the Phase II forecast in the later years. This is driven primarily by changes in ERCOT's forecasting methodology.

## Figure III-2: ERCOT Peak Demand Forecast
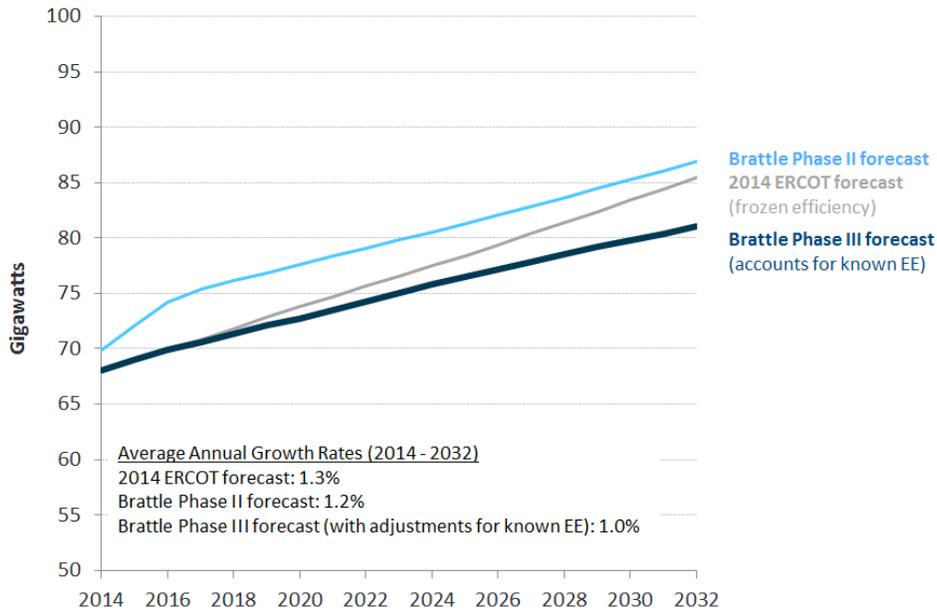


Sources:  2014 Annual Energy Outlook Table 73 and 2014 ERCOT Long Term Hourly Peak Demand and Energy Forecast

Our new peak demand forecast is lower than the Phase II study in all years of the forecast horizon.  This is due both to accounting for the impact of known efficiency improvements as well as ERCOT revisions to their forecasting methodology that assume slower overall growth in peak demand.  The following chapter on energy efficiency programs provides additional information on this data item.

### B.  NATURAL GAS PRICES

In our Phase II work we generally adopted EIA's AEO 2013 forecast for natural gas prices.  In the current phase we again rely primarily on the recently-released AEO 2014 for both our base price and high price cases.  However, in the base price case we replace 2014-2016 prices with actual current Henry Hub annual forward prices.  Both AEO and futures Henry Hub prices are adjusted with the same Texas basis differential employed in Phase II.

Figure III-3 displays our natural gas price assumptions along with gas prices we employed in Phase II in real (inflation-adjusted) dollars.  On this chart the line labeled Base Price is based on EIA Reference case prices with the first two years as forwards and basis-adjusted throughout. The line labeled high gas prices corresponds to the Low Oil and Gas Resources case in EIA's AEO forecast.  In the new Phase III Reference case, gas prices are a little higher than AEO 2013, with the average differences being about $0.50/MMbtu before 2020 and about $0.30/MMbtu after 2020.  In addition, 2014 (Phase III) base gas prices have more variability, increasing and decreasing in real terms slightly over two cycles until they begin to increase smoothly in 2021.

In the high gas price case, gas prices in Phase III (AEO 2014 plus basis) are more or less similar to the ones in AEO 2013 before 2022, but then increase thereafter at a faster rate than in AEO 2013, resulting in $0.80/MMbtu higher than the price in AEO 2013 by 2032. The average annual growth rate for the updated gas prices between 2013 and 2032 is 3.1% for the Reference Case and 4.6% for the high gas price case. By 2032, Phase III gas prices are forecasted to be around $6/MMbtu for the reference case and $8/MMbtu for the high gas price case.

### Figure III-3 Natural Gas Price Assumptions
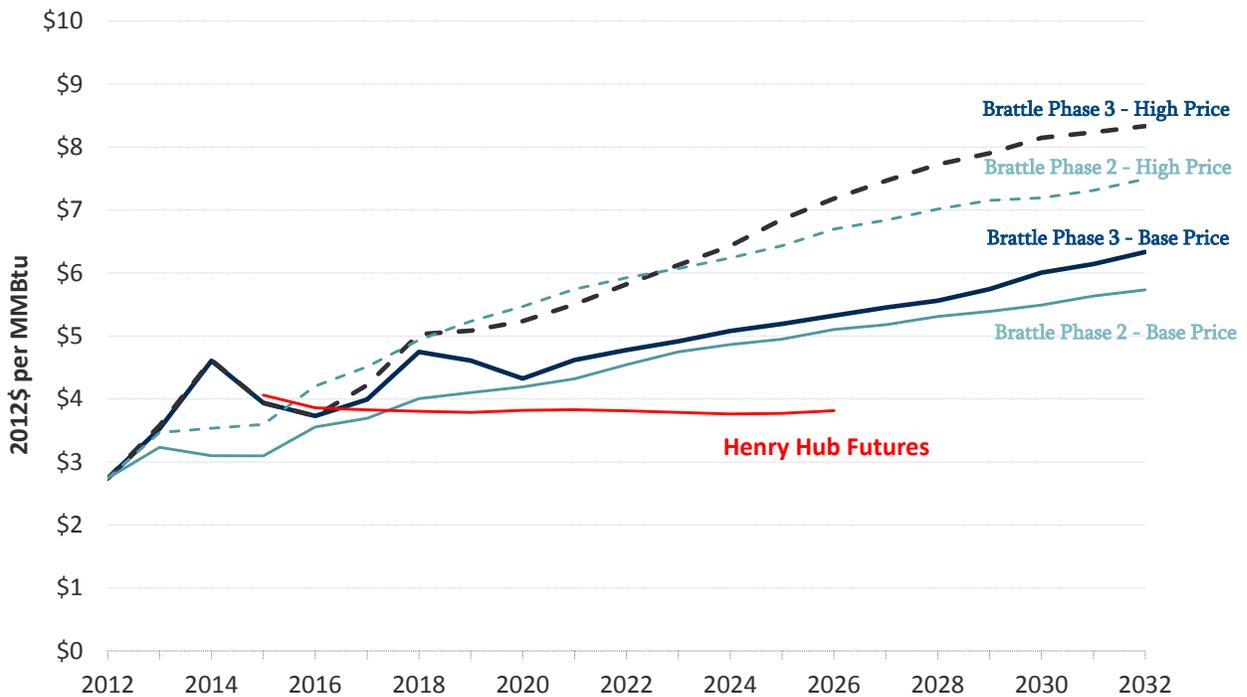


Source: Brattle prices based on EIA's Annual Energy Outlook 2013 and Annual Energy Outlook 2014 Reference and High Resource cases; NYMEX futures for Henry Hub from 2/19/2014

## C. OTHER FUEL PRICES

We have generally adopted the most recent fuel price forecasts from the EIA and our assumption for coal, gas, oil, and nuclear fuels. These forecasts are summarized in Table III-1. As can be seen, coal and nuclear prices are expected to be essentially constant in real terms in all our scenarios.

### Table III-1: Overview of Fuel Price Assumptions

| Fuel | 2012 Price ($2012) | Real Average Compound Growth Rate, 2013-32 | Source |
|---|---|---|---|
| Coal | $1.85 (Lignite) $1.99 (PRB) $1.67 (Petroleum Coke) | Constant Real Prices | SNL Energy Delivered Fuel Prices and 2013 AEO |
| Natural Gas | $1.90 - $3.49 (Monthly) | Reference: 3.1% High: 4.6% | SNL Energy 2012 Historical Texas Hub Prices and EIA 2013 |
| Biomass | $2.50 | Constant Real Prices | Authors' assumption |
| Nuclear Fuels | $0.45 | Constant Real Prices | Authors' assumption |

## D. GENERATION OPTIONS

Table III-2 lists the technology options we assume the market uses to select new capacity additions. The attributes for each capacity option are derived from a variety of sources, including ERCOT, EIA, and other sources. Note that advanced CC units are assumed to become available in 2020 and that all capital and operating costs are assumed to decline slightly over time to reflect learning curve effects and other technological improvements.

With a few exceptions described below, the performance and cost attributes of existing and planned generating units was based on ERCOT's Interconnection: Long-Term Transmission Analysis, which was performed with the support of the DOE Long Term Study (LTS).[11]

With regard to fixed operations and maintenance (FOM) costs for existing steam units, in place of ERCOT assumptions we assumed that FOM rises by $600 per MW per year of operation based on EPA estimates.[12] As noted in Section III, increased FOM and variable O&M (VOM) due to the cost of environmental retrofit installations are based on Brattle's internal analysis.

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[11] http://www.ercot.com/content/committees/other/lts/keydocs/2013/DOE_LONG_TERM_STUDY_-_Draft_V_1_0.pdf.

[12] Adapted from IPM 2006 Base Case Assumptions, Section 4.

## Table III-2: Summary of New Generation Option Attributes

| Generator Option | Heat Rate (Btu/kWh) | VOM ($/MWh) | FOM ($/kW-yr) | 2013 Capital Cost ($/kW) | Percent Decrease by 2025 (%) | Operating Life (yrs) |
|---|---|---|---|---|---|---|
| Gas turbine, pre-2020 | 10,000 | $2.00 | $7.12 | $677 | 0.0% | 30 |
| Gas turbine, 2020 on | 9,650 | $2.00 | $7.12 | $677 | 0.0% | 30 |
| Combined-cycle gas, pre-2020 | 7,050 | $2.70 | $14.91 | $890 | 4.2% | 30 |
| Combined-cycle gas, 2020 on | 6,430 | $2.70 | $14.91 | $869 | 1.9% | 30 |
| Wind | 0 | $0.00 | $28.63 | $2,074 | 14.2% | 20 |
| Solar PV, utility scale | 0 | $0.00 | $17.03 | $3,403 | 45.6% | 30 |
| Coal with CCS | 11,950 | $7.50 | $64.47 | $4,575 | N/A | 50 |
| Nuclear | 10,300 | $4.08 | $90.53 | $5,113 | -5.5% | 60 |
| Biomass | 13,000 | $9.69 | $102.51 | $3,401 | 4.3% | 40 |
| *Source Notes* | *Authors' analysis* | *ERCOT DOE LTS* | *ERCOT DOE LTS* | *ERCOT DOE LTS* | *Authors' analysis* | *Authors' analysis* |

In addition to the capital costs specified in Table III-2, generating units must also face electrical interconnection costs. Fossil-fueled generating units are charged $30 per kW while renewable generators are charged $100 per kW for interconnection costs. These costs remain constant over the modeling horizon in real terms.

Existing non-nuclear units are retired as specified in ERCOT's data files, with the exception of wind power generators. Nuclear units are forced to retire after 60 years of operations, based on a 40 year lifetime plus 20 year life extension. The physical lives of solar PV and wind plants were assumed to be 30 and 20 years, respectively. Natural gas-fired simple and combined cycle units were not given a fixed life, but are assumed to require a turbine overhaul with a cost equal to 45% of the unit's initial capital cost, adjusted for inflation, to continue operating past 30 years. If the simulation system finds this upgrade to be uneconomic, the unit is retired.

New nuclear were allowed to be added with 2025 as their earliest commercial operation date, but this option was never selected. New hydroelectric plants were not considered.

### E. ERCOT MARKET RULES

Our models reflected ERCOT's current energy market, with the current power balance penalty curve (PBPC) approach to scarcity pricing. The system's real-time (RT) price caps are set at $5,000/MWh until 2014, $7,000/MWh until 2015, and then $9,000/MWh.[13] The initial level of required ancillary services are:

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[13]   PBPC "dummy" units are able to meet the responsive reserve and allow real generating units to meet energy needs. This mimics the process used by the SCED system in ERCOT.

- Regulation reserves assumed to be 600 MW for regulation up and 600 MW for regulation down

- Responsive reserves are 2,800 MW, of which 1,205 MW can be met by demand-side resources, so only model 1,595 MW of responsive reserves from generating units

- Non-spin reserves are assumed to be 1,500 MW

In scenarios with high levels of wind and solar penetration, specifically the Strong Federal Carbon Policy scenario, the ancillary service requirements were adjusted to maintain reliable system operation under increased variability and uncertainty. Moreover, we found that to ensure reliable intra-day operations the system would have to set aside a certain amount of capacity that can be committed intra-day to cover for day-ahead (DA) renewable forecast errors. We modeled this as a day-ahead requirement for a new ancillary service we term Intra-day Commitment Option (ICO). The requirement is a function of DA forecast uncertainty, and can be met by spinning capacity as well as the capacity of offline units that can be started intra-day – CC, CT or IC. While we modeled the ICO requirement, we note that potentially a similar effect may be attained in practice without an explicit ancillary service requirement. For example, market participants may set aside capacity from the DA market to offer it into the RT markets in situations of high DA renewable forecast levels (which may lead to scarcity and high RT prices if the high DA forecast does not materialize). Also, forecast improvements, increased resource diversity and changes to the DA timing may help reduce the impacts of renewable forecast errors.

A more detailed discussion of operational assumptions is provided in Appendix B in our report for Phase II[14].

## F. WIND AND SOLAR – COSTS AND POLICY TREATMENT

Our scenario with lower renewables costs creates a lower overall capital cost trajectory for wind and solar energy, as shown in Figure III-4. This trajectory is based on recent cost projections by the Electric Power Research Institute (EPRI) as well as the authors' analysis of wind and solar cost trends. From the range of future costs estimated by EPRI, we employ a 2015 value towards the low end of the range and reduce costs by 0.25% per year, based on EIA's most recent estimates. We employ a 2015 PV cost near the high end of EPRI's range and reduce costs 2.6% per year, much less than recent history but a reasonable going-forward forecast. As the figure shows, the low-cost scenario represents about a 15 percent reduction in solar and wind capital costs in 2032, which is less than the cost declines embedded in the reference case between now and 2032 for solar. Nevertheless, as shown in the results section, even this relatively modest change in cost is impactful.

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[14] Exploring Natural Gas and Renewables in ERCOT: Part II: Future Generation Scenarios for Texas, December 10 2013, http://www.texascleanenergy.org/TCEC_Report%20Final%20Clean%2012%203%2013.pdf

The policy treatment of renewable energy resources is also a significant factor in expansion decisions. We first assume that the Texas renewable portfolio standard (RPS) rule currently in place remains unchanged through 2032, treating its goals as a firm requirement. Our models also assume that the current wind production tax credit (PTC) is available to units online by the end of 2015 based on recent IRS guidance. Purely to create a mid-course assumption regarding the continuation of the wind PTC, we assume the tax credit will continue in its present form at a reduced rate over a four-year phase-out period, declining 25% per year 2016-2019. Similarly, we assume that the current 30% investment tax credit for PV plants is available to all Texas additions through 2016 and then decreases to 10% for the remainder of the period.

As noted in the introduction, our models do not implement any distribution-system-related changes or costs related to PV. As a result, our PV additions are best interpreted as utility-scale solar installations rather than rooftop systems. We assume these solar PV units are located across the ERCOT footprint.

New wind units could be constructed in the Southern ERCOT region, the Northwestern Texas CREZ region, and the Panhandle, but total wind installed in the Southern region was limited to 5 GW total based on ERCOT's guidance.

Finally, the relatively new supply chains installing wind and solar plants and the requirements to adjust market processes as variable resources grow prompted us to place limits on the maximum amount of wind or solar the market could add in one year. Based on our own analysis of wind and solar growth patterns, (see Appendix C in our report for Phase II[15]) we limit solar additions to a maximum rate of growth of 3000% during their first year of installation and 300% all subsequent years.[16] In addition, aggregate solar installations are limited to 50% of maximum coincident hourly load, a limit of 24.3 GW which is not reached in any of our scenarios through 2032. Wind additions are similarly limited to 3,000 MW/year statewide.

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[15]  Exploring Natural Gas and Renewables in ERCOT: Part II: Future Generation Scenarios for Texas, December 10 2013, http://www.texascleanenergy.org/TCEC_Report%20Final%20Clean%2012%203%2013.pdf

[16]  Although 3000% may sound like a large addition, it is operating off a small base of 132.4 MW as of Q2 2013, according to the SEIA/GTM Research Solar Market Insight. A 3000% increase would amount to approximate 4,000 MW, an amount that large solar markets have been able to add in some markets around the world.

## Figure III-4: Wind and Solar Capital Cost Assumptions
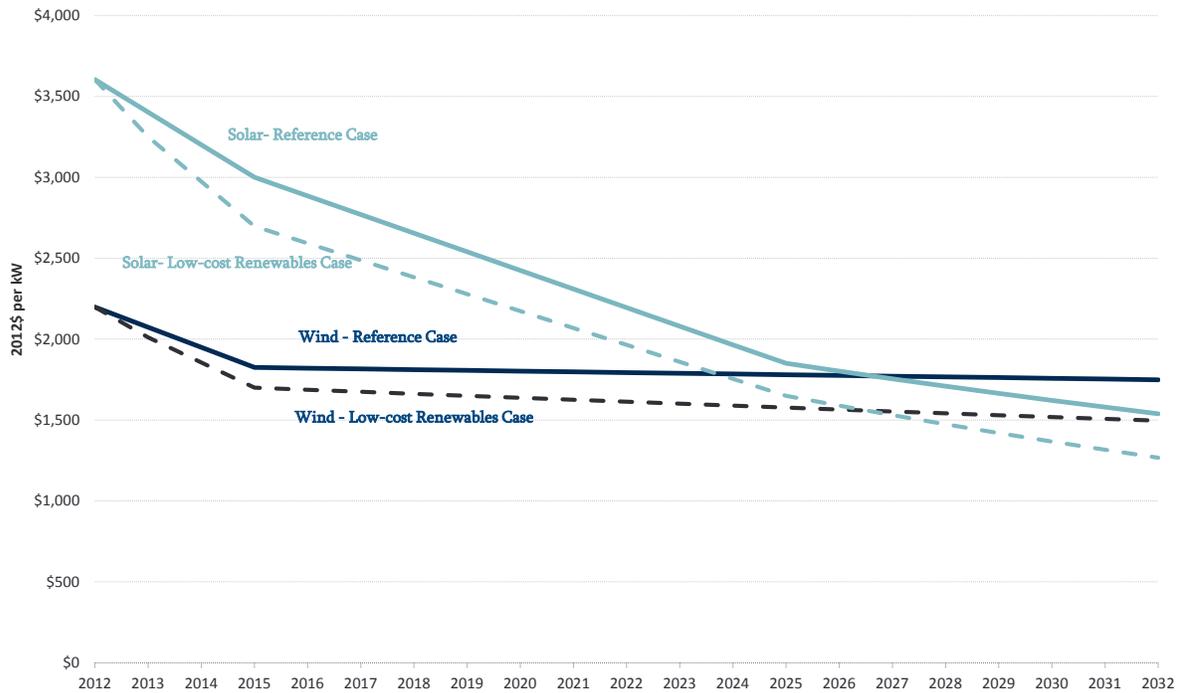


Source: Based on EPRI's Integrated Generation Technology Options 2012 report

### G. TRANSMISSION SYSTEM ASSUMPTIONS

ERCOT was simulated as four interconnected sub-regions: Central ERCOT, the South Region, the Northwestern Texas CREZ Region, and the Panhandle. In PSO we also model the import limits into the major metropolitan areas: Houston, Dallas Forth Worth, (DFW), San Antonio and Austin.

It is important to note that we assumed a CREZ-like rate treatment for the recovery of transmission expansion costs in our analysis. We assumed that transmission expansion costs were recovered via a system-wide equal volumetric tariff on all transmission in ERCOT. Under this treatment, the costs of these transmission upgrades were not charged to the new generation sources seen as the primary cause of the upgrade. Were we to change this treatment, it is likely that the new sources required to pay for these upgrades (primarily new wind plants) would be built significantly less frequently in our simulations, tilting new construction towards the next cheapest alternatives, primarily gas and solar additions close to loads.

### H. STORAGE TECHNOLOGIES

We have not modeled storage as an available large-scale *energy* option for ERCOT developers. This decision does not reflect a view that storage has no near-term future in the power industry.

Instead, our preliminary research simply found that, in the range of [deterministic] natural gas prices contained in our scenarios, large-scale storage was unlikely to be a market-selected option through 2030.[17] We believe it is much more likely that certain storage technologies may provide competitive ancillary services during the study period, including regulation. This creates a slight bias in favor of natural gas technologies, which are the primary alternative source of fast-acting regulation. However, the difference is limited to about 1,300 MW in regulation, which is the largest amount of this service required in any of our scenarios.

## I. MARKET RULES AND THE REQUIRED RESERVE MARGIN

Our modeling system attempts to replicate the series of markets operated by ERCOT, specifically all energy and ancillary services markets. In Phase II, we saw evidence that ERCOT was considering the establishment of a mechanism to ensure a 13.75% mandatory reserve margin, higher than the current ERCOT market would naturally achieve. As a result, most of our Phase II scenarios included a capacity-like payment that provides revenues sufficient to cause the market to build to the mandated reserve level.

We learned in Phase II that the mandatory reserve margin generally had a modest effect, increasing the life of existing gas plants and causing more new gas to be built:

> As expected, the addition of a required reserve margin makes a few significant changes to the results of the first reference case, but the basic character of our findings is quite similar. Most significantly, about 2,700 MW of the older steam turbine units no longer retire, as the capacity payments they receive are sufficient to keep them operating even when they receive virtually no energy or ancillary services margins. In addition, about 2,000 MW of additional combined cycle plants, 260 MW more CTs, and 500 MW more Panhandle wind is constructed by 2032. Net total 2032 installed capacity increases by 18.2 GW, 5 GW more than the reference scenario, indicating the intended effect of the reserve margin policy.[18]

As of early 2014, the outlook for a required reserve margin above market-established levels and the mechanism for achieving such a margin remains unclear. As a result, we have omitted a mandatory reserve mechanism from our Phase III scenarios. Recognizing that its effect is generally to favor existing and new fossil fuel assets relative to wind and solar plants, we hope that readers can extrapolate from our Phase III scenarios to get a useful picture of the impact of a 13.75% reserve mandate.

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[17]   In addition, most forms of pumped storage and compressed air energy storage require a type of geographic site that is not commonly found in Texas.

[18]   Exploring Natural Gas and Renewables in ERCOT: Part II: Future Generation Scenarios for Texas, Dec., 2013, http://www.texascleanenergy.org/TCEC_Report%20Final%20Clean%2012%203%2013.pdf, p.29.

## J. EMISSION RULES AND CARBON EMISSIONS SCENARIOS

In all scenarios we assume that state and federal environmental rules pertaining to power generators remain in place. In particular, the Environmental Protection Agency (EPA) Mercury and Air Toxics Rule (MATS) is enforced by 2016, so by that date all coal and oil units must install or have installed some combination of scrubbers, active carbon injection (ACI) or particulate controls ("Baghouses" or upgraded electrostatic precipitators (ESPs)) as well as some form of $NO_x$ controls (Selective **Catalytic Reduction** (SCR) or **Selective Non-Catalytic Reduction** (SNCR)). The costs of these pollution controls are in addition to unit-specific base case O&M costs provided to us by ERCOT and impact both the fixed and variable O&M costs of coal units.

Actual estimates of the incremental costs of adding these pollution controls are based on a separate Brattle Group analysis of the impact of the EPA MATS rule on coal-fired generators.

This analysis begins with retrofit technology cost assumptions from EPA's Integrated Planning Model (IPM) and a 2011 Edison Electric Institute (EEI) study and examines each Texas plant's expected cost of compliance with the MATS rule.[19] In all our scenarios, these compliance outlays alone are not significant enough to trigger any economic retirements of the existing ERCOT coal fleet.

Our final two scenarios examine two possible forms of an EPA rule requiring Carbon Capture and Sequestration (CCS) on all new and existing ERCOT coal-fired plants. In Scenario 3, we apply all reference case assumptions as well as a rule requiring coal plants to capture and sequester 50% of their $CO_2$ output by the year 2025. Scenario 4 is the reference case plus an assumed rule requiring 90% $CO_2$ capture. The costs of adding CCS to plants at both levels is derived from DOE's National Energy Technology Laboratory (NETL) report[20] and is assumed identical across all ERCOT plants.

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[19]   EPA IPM Base case V4.10 (Aug 2010).

[20]   DOE/NETL-401/110907, Carbon Dioxide Capture from Existing Coal-Fired Power Plants.

# IV. Characterizing Demand Response in ERCOT

Our market simulations explore the impacts of existing DR programs in ERCOT as well as an expanded portfolio of new DR options. Accurately representing these programs in our models requires careful characterization of each DR resource. In this chapter, we first describe our characterization of the existing DR programs. We then discuss our development of the new DR options and compare their potential impact to estimates of peak reduction potential from other studies.

## A. EXISTING DEMAND RESPONSE

There is currently roughly 2,500 MW of coincident peak reduction capability across all DR programs in ERCOT, representing about 4 percent of the system peak.[21] These DR programs mostly target the load of large commercial and industrial (C&I) customers. The programs are utilized on a relatively limited basis, being dispatched primarily as a last-resort option in response to concerns about system reliability. A brief description of each DR option in ERCOT is included below.[22]

- **Transmission and Distribution Service Provider (TDSP) load management programs.** These programs provide payments to large C&I customers for verified load reductions. There is a relatively high eligibility size threshold of 750 kW (and 100 kW of load reduction capability). The programs are limited to 19 hours of dispatch per year, with 30-minute notification before an event.

- **ERCOT's Emergency Response Service (ERS) program.** Participants agree to reduce load to a firm level on 10- or 30-minute notice. There is a limit of 8 hours of dispatch per season and period, although participants can bid to provide load reductions for multiple periods and seasons.

- **ERCOT's Load Resources program.** Formerly referred to as "Load Acting as a Resource" or "LaaR," the Load Resources program is similar to ERS in that large customers commit to providing firm load reductions. The Load Resources program is the largest of ERCOT's DR programs.

- **Municipal utility direct load control programs.** In addition to the ERCOT programs, City Public Service San Antonio (CPS) and Austin Energy offer residential direct load control (DLC) programs. In these programs, the utility installs a switch on the compressor of the customer's air-conditioner or, alternatively, the customer is equipped with a smart thermostat. During DR events, the air-conditioner is cycled, or the thermostat set point is increased, to reduce electricity consumption. These

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[21] The 2,500 MW estimate has been grossed up to account for line losses.

[22] For further information on ERCOT's DR programs, see: http://www.ercot.com/services/programs/load.

programs are operated by the utilities, although there is some coordination with ERCOT regarding the dispatch of the programs. Retail Electric Providers (REPs) are beginning to offer these types of programs as well.[23]

Each of these programs has been included in our study as a resource that is available throughout the forecast horizon at its current level of enrollment. To characterize the size of each resource, we relied primarily on information that was developed jointly by Brattle and ERCOT in a recent reserve margin study for the Public Utility Commission of Texas (PUCT).[24] We made additional updates to these estimates where new information had become available. For example, new ERS resource procurement data was released in January 2014. We have updated our ERS capacity estimate based on this data, as it represents a significant increase in the size of the resource relative to the Brattle reserve margin study (an increase of around 300 MW).[25] Similarly, based on conversations with ERCOT, we have reduced the peak reduction capability of the TDSP programs from 241 MW in the prior study to 200 MW (before accounting for line losses).

The operational characteristics of the DR programs were based on the findings of the Brattle reserve margin study, a review of historical dispatch of the programs, and a review of DR program documentation from the TDSPs, municipally-owned utilities, and ERCOT. Each program is assumed to be dispatched at close to the System-Wide Offer Cap (SWOC), since this would approximately represent the price conditions during reliability situations that would trigger a DR event.[26] The size and operational characteristics of each existing DR program are summarized in Table IV-1 below.

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[23] For example, Reliant has partnered with smart thermostat maker Nest to provide customers with a free thermostat and an 80 cents/kWh payment for load reductions during peak periods when enrolled in Reliant's DLC program. https://www.reliant.com/en/residential/my-reliant/save-energy/smart-energy-solutions/degrees-of-difference/degrees-of-difference-with-nest.jsp\.

[24] The study was designed to estimate the economically optimal reserve margin in ERCOT. See Samuel A. Newell et al., "Estimating the Economically Optimal Reserve Margin in ERCOT," prepared for the Public Utility Commission of Texas, January 21, 2014. http://brattle.com/system/publications/pdfs/000/004/978/original/Estimating_the_Economically_Optimal_Reserve_Margin_in_ERCOT_Revised.pdf?1395159117.

[25] See the ERS section of ERCOT's website for procurement details: http://www.ercot.com/services/programs/load/eils/.

[26] Our modeling system requires that the programs be dispatched based on economics, so we have developed this as a proxy reliability-based dispatch. ERCOT sometimes dispatches these programs during reliability events that do not coincide with the SWOC

## Table IV-1: Existing DR Options in ERCOT

| | TDSP Load Management Programs | ERCOT 10-minute Emergency Response Service (ERS) | ERCOT 30-minute Emergency Response Service (ERS) | ERCOT Load Resources (LRs) | Muni Direct Load Control Programs |
|---|---|---|---|---|---|
| **Operational Characteristics** | | | | | |
| Peak-coincident capacity (MW, grossed up for losses) | 209 | 630 | 127 | 1,205 | 376 |
| Minimum run time (hours per interruption) | 1 | 1 | 1 | 1 | 1 |
| Maximum run time (hours per interruption) | 4 | 8 | 8 | 8 | 4 |
| Maximum interruptions (per day) | 1 | 1 | 1 | No limit | 1 |
| Maximum hours dispatched (total hours per year) | 19 | 8 | 8 | No limit | 40 |
| Maximum events (total events per year) | 5 | 8 | 8 | No limit | 10 |
| Hours of day when resource can be dispatched | 1 pm to 7 pm | Any hour | Any hour | Any hour | 1 pm to 8 pm |
| Months of year when resource can be dispatched | June - Sept | Any month | Any month | Any month | May - Sept |
| Required notification before an event (hours or minutes) | 30 minutes | 10 minutes | 30 minutes | 10 minutes | 10 minutes |

*Notes:*
*Capacity values are peak-coincident and grossed up for losses.*
*ERS values are based on procurement for February-May 2014 and represent average of Business Hours 3 and 4 values.*
*ERCOT's Load Resources capacity only includes participation in the "non-controllable" option. The controllable option is storage and is accounted for in our representation of supply.*
*ERCOT's most recent estimate for Non-controllable Load Resources (1,231 MW) became available after our figures were finalized. The difference does not materially affect our results.*
*TDSP load management program capacity estimate provided by ERCOT (before grossing up for losses).*

There are also some resources that provide load reductions in ERCOT but which were not modeled as dispatchable existing DR resources in our study. For example, customers who are enrolled in time-varying retail rates would be expected to reduce load during high priced hours of the day (this is sometimes referred to as "price responsive demand"). We have assumed that the impact of existing price responsive demand is captured in ERCOT's updated load forecast, and have further modeled an increase in enrollment in time-varying rates as one of the new DR options in our study (as discussed below). Similarly, customers most likely reduce their demand in response to "4CP" charges from the TDSPs. These charges are designed to convey peak demand-related transmission and distribution costs and are incurred by customers during the hours of the system peak. We have assumed that these impacts are also embedded in the load forecast, as customers have been facing 4CP charges for many years. We have excluded ERCOT's Controllable Load Resources program from our DR portfolio, because it consists of energy storage that is captured in our representation of the region's electricity supply. Energy efficiency impacts are included and accounted for separately, as discussed in Chapter V.

### B. THE PORTFOLIO OF NEW DR OPTIONS

According to data in Federal Energy Regulatory Commission's (FERC) *2012 Assessment of Demand Response and Advanced Metering*, ERCOT's 4 percent peak reduction capability ranks the lowest among organized markets in the U.S.[27] This may not be an entirely appropriate comparison, as ERCOT's programs are currently designed to provide reliability support at any

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[27]    FERC, "2012 Assessment of Demand Response and Advanced Metering," December 2012.

time of day, year-round, rather than being focused purely on the system peak. ERCOT also has more DR participation in ancillary services markets than is observed in the other regions. However, the FERC data still provides an indication that there is untapped DR potential in ERCOT. This is supported by DR potential studies that have arrived at a similar conclusion.[28]

We developed a plausible portfolio of new DR options to better understand the potential impacts of expanded DR adoption. The potential impact of these new programs is entirely incremental to the existing programs discussed above. Importantly, the new portfolio does not represent the maximum amount of cost-effective DR that could be achieved in ERCOT. We have been intentionally conservative in our assumptions about the breadth of the new DR program offering, its enrollment rates, and its impacts. We have chosen a realistic set of DR options based on a national review of DR programs that has been tailored to ERCOT's market characteristics. Further, our study does not speculate specifically as to how these programs would be rolled out, such as through a new policy initiative or through a gradual and natural expansion of REP product offerings driven by market competition.

The new DR programs that we have modeled are described below:

- **Air-conditioning DLC for residential and small C&I.** This program would be similar to the DLC programs offered by Austin Energy and CPS (described above), but would be deployed statewide. Air-conditioning load among residential and small C&I customers can drive over half of the summer peak and is a significant source of untapped DR potential in Texas. In characterizing this program, we use assumptions from a Brattle study that was presented at a PUCT workshop in 2012.[29] Roughly 20 percent of eligible residential customers (those with central air-conditioning) and 10 percent of small C&I customers (defined as having less than 20 kW of demand) are assumed to participate at a moderate incentive payment level. To be conservative, this is significantly lower than participation in some of the most successful DLC programs in the U.S., such as Baltimore Gas & Electric's Smart Energy Rewards program and Xcel Energy's Savers Switch Program in Minnesota, both of which have achieved over 50 percent enrollment among eligible customers. The per-participant load reduction is assumed to be 1 kW for residential customers and 2 kW for small C&I, based on a national review of the impacts of existing DLC programs.

- **Interruptible tariffs for medium and large C&I.** Interruptible tariffs provide C&I customers with a financial incentive to reduce load by a verified and pre-specified amount – or to a pre-specified level – during DR events. The financial incentive

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[28] These studies, by the American Council for an Energy-Efficient Economy and FERC, are summarized later in this chapter.

[29] Ahmad Faruqui, "Direct Load Control of Residential Air Conditioners in Texas," presented to the Public Utilities Commission of Texas in Austin, TX, October 25, 2012.

typically comes in the form of a rate or bill discount. The key difference between our new program and the types of C&I programs already offered by ERCOT is that our new program would be dispatched based on economics rather than reliability. The program would also be less operationally constrained, e.g., there would be a higher limit on the number of hours per year it can be dispatched. Enrollment assumptions are based achieved participation rates in similar programs around the U.S., as reported in FERC's bi-annual survey of DR programs.[30] At a moderate incentive payment, we assume 20 percent of medium C&I load and 30 percent of large C&I load participates in some form of DR program (these estimates include participation in the existing programs). Participants are assumed to reduce load by 50 percent during DR events when enrolled in the interruptible tariff.[31]

- **Dynamic pricing for all customer classes.** Advanced metering infrastructure (AMI) has been fully deployed across the ERCOT footprint. This means that the necessary metering capability is now in place to offer any customer a time-varying rate. More than 200 tests of time-varying rates conducted in the U.S. and internationally have shown that customers will reduce peak demand in response to time-varying rates.[32] For our study, we have assumed that customers will have the option to enroll, on an opt-in basis, in a critical peak pricing (CPP) rate. The CPP rate charges a higher price during the peak hours of the day on a very limited number of days per year In this case, we assume 10 critical peak pricing days per year and a peak period duration of 5 hours, representing 50 total high priced hours per year. The rate is discounted during all remaining 8,710 hours of the year. We assume that the ratio between the peak price and the off-peak price is 8-to-1 (e.g. a peak price of 75 cents/kWh and an off-peak price of 9.3 cents/kWh). The associated average peak reduction per participant, by class, is simulated based on Brattle's comprehensive review of dynamic pricing pilots that have been conducted over the past decade.[33] Residential participants would reduce peak demand by 13 percent, small C&I by 0.6 percent, medium C&I by

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[30] FERC surveys utilities and ISOs/RTOs every two years to collect data on their DR programs. The results of the survey are publicly available: https://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp

[31] In many interruptible tariff programs, utilities report that their participants provide load reductions that are close to 100 percent of the participant's coincident peak demand. These are likely cases where the program is utilized very infrequently. We have used a more conservative assumption of 50 percent in this case, which is similar to (but lower than) the 70 percent assumption in FERC's 2009 *A National Assessment of Demand Response Potential*.

[32] For general background on time-varying rates, see Ahmad Faruqui, Ryan Hledik, and Jennifer Palmer, "Time Varying and Dynamic Rate Design," prepared for the Regulatory Assistance Project, July 2012.

[33] For further detail on customer response to peak prices, see Ahmad Faruqui and Sanem Sergici, "Arcturus: International Evidence on Dynamic Pricing," *The Electricity Journal*, August/September 2013.

7 percent, and Large C&I by 8 percent. Enrollment in the CPP is assumed to be 15 percent of the customer base, which is lower than has been observed in other voluntary time-varying rate deployments.[34]

### Table IV-2: The New DR Options

| | Residential Air-Conditioning DLC | Small C&I Air-Conditioning DLC | Medium C&I Interruptible | Large C&I Interruptible | All Customers CPP |
|---|---|---|---|---|---|
| **Operational Characteristics** | | | | | |
| Peak-coincident capacity (MW, grossed up for losses) | 1,267 | 235 | 1,917 | 21 | 1,074 |
| Minimum run time (hours per interruption) | 1 | 1 | 1 | 1 | 5 |
| Maximum run time (hours per interruption) | 5 | 5 | 5 | 5 | 5 |
| Maximum interruptions (per day) | 1 | 1 | 1 | 1 | 1 |
| Maximum hours dispatched (total hours per year) | 75 | 75 | 75 | 75 | 50 |
| Maximum events (total events per year) | 15 | 15 | 15 | 15 | 10 |
| Hours of day when resource can be dispatched | Noon to 8 pm | Noon to 8 pm | Noon to 8 pm | Noon to 8 pm | 2 pm to 6 pm |
| Months of year when resource can be dispatched | May - Sept | May - Sept | May - Sept | May - Sept | May - Sept |
| Required notification before an event (hours or minute | 10 minutes | 10 minutes | 1 hour | 1 hour | 1 day |
| **Cost Characteristics** | | | | | |
| Up-front cost ($/kW) | $150 | $75 | $0 | $0 | $0 |
| Annual cost ($/kW-year) | $43 | $41 | $92 | $92 | $10 |
| Variable cost ($/MWh) | $0 | $0 | $0 | $0 | $0 |

*Notes:*
*Capacity values are peak-coincident and grossed up for losses.*
*All capacity values are incremental to impacts of existing DR programs.*
*Capacity values are shown for the year 2020, which is the first year that the program is assumed to reach "steady state" enrollment*
*DLC equipment costs are assumed to be shared between the participant and the program administrator.*

Comparing Table IV-1 to Table IV-2 highlights the key differences between the existing portfolio of DR programs and our new DR options. First, our new options would have the flexibility to be dispatched during a larger number of hours per year (50 to 75) than the existing programs. Second, whereas the existing programs are dispatched mostly for reliability purposes, our new programs could be dispatched for economic purposes as well. In this sense, the new DR options are roughly equivalent to a very energy-constrained hydro unit – there is no variable cost associated with their dispatch, only a limit on the number of hours over which they can be utilized. Finally, while the existing programs are assumed to be in place throughout the forecast horizon, our new DR options will only be added to the portfolio if it is economic to do so. Each new DR option has an up-front "installation" cost (e.g. equipment costs, such as the cost of a smart thermostat) and annual costs (e.g. the incentive payment and general overhead) that will

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[34] Arizona Public Service, for example, has over 50 percent of its residential customers enrolled in a time-of-use (TOU) rate. In many parts of the country, time-varying rates are the default or mandatory option for large C&I customers. When surveyed, more than 1-in-5 customers are typically identified as being highly likely to enroll in a time-varying rate.

determine this decision in our model. These costs are based on a review of utility DR programs in other jurisdictions.[35]

Among the new DR options, residential DLC, medium C&I interruptible tariffs, and CPP for all customers could each produce peak reductions of more than 1 GW. The residential class is relatively untapped currently, with very few DR options available to it, but with a significant portion of the summer peak being driven by its air-conditioning load. The medium C&I segment is similarly untapped through current programs. The potential impact of the CPP rate is large in part because it is applicable to all customer classes and has no eligibility restrictions (since virtually all customers now have a smart meter). The Large C&I customer segment is already participating at significant levels in ERCOT's DR programs and therefore has less incremental peak reduction potential. The small C&I segment generally accounts for a relatively small share of the system peak. The extent to which each of these options is cost-effective will be determined through our market simulations.

Each program could be offered at a range of incentive payment levels. Not surprisingly, market research studies and actual program experience have found that enrollment in DR programs increases as the incentive payment rises.[36] Rather than choosing a single incentive level for each program, we have modeled each program as having five different possible incentive payments (*i.e.* annual costs) and five associated aggregate peak impact levels (which are driven by participation). Thus, each program effectively has its own associated "supply curve," allowing our modeling suite to choose the economically optimal incentive at which to offer each program.[37] Based on a review of market research studies we have observed that, within a reasonable range of incentive payments, doubling the incentive payment results in a 50 to 100 percent increase in participation, although this general rule varies by customer segment, program type, and utility service territory.

The peak reduction capability of the new programs will vary over the forecast horizon. We assume that 2016 is the first year in which the programs can be offered. There is roughly a five year participation ramp-up period from each program's inception to the year in which it reaches full "steady state" participation. At that point, participation is assumed to grow at the peak

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[35] For example, see the program details in Xcel Energy Colorado's recent DR potential study. https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=210750&p_session_id=. We assume that DLC equipment costs are shared between the participant and the program administrator (e.g. the program administrator offers an incentive to install the new smart thermostat).

[36] This is based largely on a review of non-public market research studies. However, for an illustration of the relationship between residential DLC participation and incentive payments in existing DR programs, see Andy Satchwell and Ryan Hledik, "Analytical Frameworks to Incorporate Demand Response in Long-Term Resource Planning," *Utilities Policy*, 2014.

[37] There is no incentive payment associated with the CPP program, so we have only modeled one "price point" for that option.

demand growth rate (in other words, enrollment is held constant when expressed as a percent of peak demand).

The inclusion of our new DR portfolio – if found to be cost-effective - would more than double the peak reduction capability of ERCOT's DR portfolio. However, this expanded DR portfolio is still significantly less than the total maximum DR potential in ERCOT that has been identified in other studies. In FERC's *National Assessment of Demand Response Potential*, for example, it was estimated that the Texas system peak could be reduced by between 14.9 and 21.3 percent through DR.[38] A 2007 study by the American Council for an Energy-Efficient Economy (ACEEE) found that peak demand could be reduced by 13.5 percent through cost-effective programs.[39] Our expanded portfolio, by comparison, represents peak reduction capability of 9.7 percent at moderate assumed incentive payment levels. Our conservative assumptions around the range of new program offerings and their enrollment levels are driving this relationship to the other studies. A comparison of the studies is shown in **Figure** IV-1.

**Figure IV-1: ERCOT Peak Demand Reduction Capability as Reported in Various Studies**
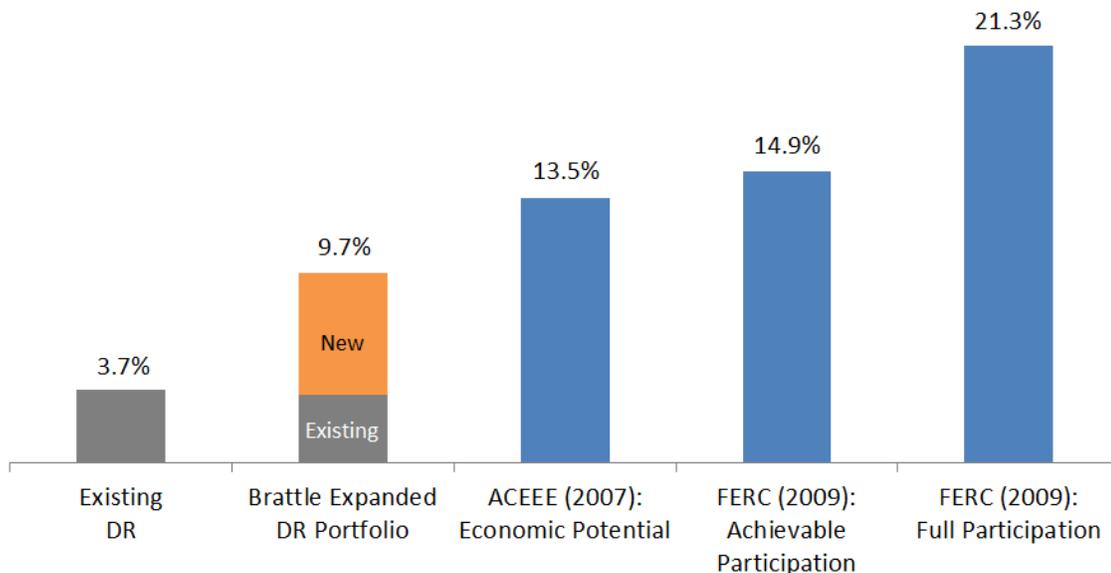


Notes:
Impact of existing DR is shown for 2014.
Impacts in the potential studies are shown for the final year of their respecive forecasts.
The impact of our expanded DR portfolio is shown for 2020
Expanded portfolio impacts are based on moderate incentive payment levels

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[38] FERC, "A National Assessment of Demand Response Potential," prepared by The Brattle Group, Freeman, Sullivan, & Co., and Global Energy Partners, June 2009.

[39] R. Neal Elliot et al., "Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas' Growing Electricity Needs," ACEEE, March 2007.

There are a number of DR options that could further expand the portfolio, but which have not been included in our study. For example, residential DLC programs do not need to be limited to control of central air-conditioners – they could also include pool pumps, water heaters, or room air-conditioners, to list a few. DLC programs being offered in other regions of the U.S. include these as options, with a higher incentive payment to compensate for the associated increased load reduction. Additionally, in our modeling of the CPP rate, we have assumed that participants are not equipped with "enabling technologies" such as smart thermostats, energy information displays, home energy gateways, or Automated DR systems. When coupled with dynamic pricing, these technologies boost DR by automating the customer's response to higher priced periods and/or by providing additional information about the customer's energy use relative to the price of electricity. Dynamic pricing pilots have found that such enabling technologies can double the amount of DR that would be provided from a dynamic pricing rate alone.[40] Further, the pricing programs could be deployed on a default basis (e.g. through time-varying T&D charges). Participation in default rate deployments is typically three to five times higher than in opt-in deployments.[41] There are many ways in which the DR portfolio could be expanded beyond the core programs that we have analyzed in this study, and those could be an interesting subject of further analysis.

The DR portfolio could also be expanded to consider a different type of DR resource, which is commonly being referred to in the industry as "DR 2.0." DR 2.0 can be used around-the-clock to both increase and decrease load on short notice in order to facilitate the integration of intermittent resources such as wind and solar. Electric water heating and commercial cooling are two end-uses that could potentially provide a significant amount of flexible load. While there is considerable emerging interest in DR 2.0, it has mostly been explored on a theoretical basis or through small-scale demonstration projects thus far. There would be substantial value in a market simulation study to assess the impact that these resources could have in addressing renewables integration concerns.

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[40] Ahmad Faruqui and Sanem Sergici, "Arcturus: International Evidence on Dynamic Pricing," *The Electricity Journal*, August/September 2013.

[41] This is based on a review of market research studies and full scale dynamic pricing deployments. IT will be the topic of a forthcoming whitepaper titled, "The ABCs of Default Time-Varying Rates."

# V. Characterizing Energy Efficiency in ERCOT

In contrast to DR, which is focused on reducing demand during high-priced hours or times of system emergencies, EE reduces electricity consumption year-round. We have included an expanded portfolio of cost-effective EE programs in certain scenarios of our study. The impacts of this expanded energy efficiency portfolio are incremental to our adjustments to ERCOT's load forecast for known/planned future efficiency improvements. In this chapter, we discuss current EE initiatives in Texas, our methodology for establishing the expanded EE portfolio, and the impact of this portfolio relative to estimates of achievable EE from other studies.

## A. RECENT ENERGY EFFICIENCY ACTIVITY IN TEXAS

Texas law requires that all TDSPs meet energy efficiency goals.[42] The law recently required that TDSP EE activities eliminate 30 percent of annual peak demand growth and is transitioning to require a 0.4 percent reduction in total peak demand.[43] To meet these goals, the TDSPs offer incentive programs (*i.e.,* payment per kilowatt or kilowatt-hour of load reduction), which are implemented by REPs and energy efficiency service providers. While it is difficult to pin down precise statewide estimates of incremental energy savings from the EE programs, the programs are estimated to have grown by between 400 GWh and 700 GWh per year since the law was established, representing nearly 5,000 GWh of total energy savings (relative to a current statewide base of around 300,000 GWh of total sales).[44] The TDSPs consistently exceed the mandated peak reduction targets.

The core EE programs – referred to as "Standard Offer Programs" - are relatively similar across utility service territories. For commercial buildings, the programs typically consist of incentives for efficient lighting, HVAC, and roofing. Higher incentives are offered for specific end-uses such as water-cooled chillers and light emitting diode (LED) light bulbs. Financing assistance, technical assistance, and education are also part of the commercial offerings. For the residential segment, incentives are similarly offered for measures such as efficient air-conditioning

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[42] The requirement was originally established by the Texas Legislature through Senate Bill 7 in 1999, and has been revised through a series of bills since, the latest being Senate Bill 1125, which passed in 2011.

[43] The PUCT's Substantive Rule §25.181 established this change. The two targets are roughly equivalent in terms of total peak demand reductions, based on recent peak demand growth. However, the transition is ultimately expected to lead to a lessening of the required reduction over time. http://www.texasefficiency.com/images/documents/EnergyEfficiencyRule/25.181texasenergyefficiencyruleeffective1.1.13.pdf.

[44] According to EIA 861 data, the incremental annual savings have averaged around 700 GWh over the past few years. The 2011 Energy Efficiency Accomplishments Report, developed by Frontier Associates, states that 529 GWh of energy savings were achieved in 2011 and that the TDSP programs had produced a total reduction of 4,639 GWh between 1999 and 2011. http://texasefficiency.com/images/documents/Publications/Reports/EnergyEfficiencyAccomplishments/eummoteeprsummary2011.doc.

(minimum SEER of 14.5), heat pumps, insulation, duct improvements, and ENERGY STAR windows and appliances. Incentives typically range up to $200 to $300 per kW, or 2 to 5 cents/kWh, depending on the measure, and are sometimes higher.

The TDSPs also offer "Market Transformation Programs" which are targeted programs aimed at overcoming market barriers to EE adoption for specific end-uses or customer segments. These programs are focused on providing energy efficiency incentives for low income customers, schools, and new construction. They also include air-conditioning installer and distributor-focused programs.

Notably, large industrial customers (mostly those served at transmission voltage) have opted out of the EE programs. This means that these customers do not fund the EE programs, and TDSP EE programs are not made available to them. Therefore, efficiency improvements in this market segment have been attributable to private investment decisions or codes and standards, rather than utility EE programs.

Since the utility energy savings targets are tied entirely to peak demand growth, it is likely that the TDSPs have pursued EE measures that are more focused on peak demand than on overall energy savings. There has been a stronger emphasis on DR than EE for this reason, since the impacts of DR programs can count toward the legislatively mandated goals (in 2011, over half of the achieved peak demand reduction was from DR programs rather than energy efficiency).[45] However, the TDSPs are also required to submit associated energy savings to the PUCT for review, to ensure that total reductions in electricity consumption are adequate and the programs are not purely peak demand focused.

In addition to state-level initiatives, federal codes and standards are also leading to improvements in statewide energy efficiency. The Energy Independence and Security Act of 2007, for example, establishes new lighting efficiency standards that will lead to substantial reductions in residential and commercial electricity consumption over the coming decade. As discussed in Chapter III, these impacts – as well as the impacts of planned utility DSM programs – have already been accounted for in our baseline demand and energy forecast.

## B. THE NEW EE PORTFOLIO

Each year, the ACEEE publishes a state energy efficiency "scorecard" ranking each state on the effectiveness of its EE policies, initiatives, and programs. Texas ranked 33rd in ACEEE's 2013 report, with some recognition for state government initiatives, building energy codes, and

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[45] Frontier Associates, "Energy Efficiency Accomplishments of Texas Investor-Owned Utilities, Calendar Year 2011."
http://texasefficiency.com/images/documents/Publications/Reports/EnergyEfficiencyAccomplishments/eummoteeprsummary2011.doc.

appliance efficiency standards, but low scores for utility energy efficiency programs.[46] This suggests that there is room for growth in energy efficiency in the state. For example, ACEEE notes that some utilities have hit caps on their energy efficiency spending that are prohibiting them from pursuing additional cost-effective EE.  This conclusion is supported by EE potential studies that have identified achievable and cost-effective – yet untapped – EE opportunities in Texas.

Studies on EE potential in Texas mostly date back to the 2007-2008 timeframe.[47] The only study that was conducted in the past three years is a 2012 assessment of EE potential by Austin Energy.[48] Austin Energy has been significantly more aggressive in its energy efficiency activities than have other utilities in ERCOT.  According to EIA data, over the past decade Austin Energy has spent roughly five times more on energy efficiency than the statewide average, when normalizing by total electricity sales.  Annual incremental energy savings from Austin Energy's DSM programs are estimated to account for roughly 15 percent of statewide incremental energy savings in 2012, despite the fact that Austin Energy accounts for only four percent of the state's total sales.[49] The average residential customer in Austin is more efficient as a result, consuming only 900 kWh per month, compared to the statewide average of 1,200 kWh per month.[50]

Since we have observed that Austin Energy's customer base is significantly more efficient than the statewide average, we can reasonably assume that the low-cost energy efficiency measures identified in Austin Energy's potential study are likely to be even more attractive options for the rest of the state.  In other words, the Austin Energy study probably excludes some attractive EE opportunities that exist elsewhere in Texas, because those opportunities have already been realized in Austin.  In this sense, the Austin Energy estimates would likely <u>conservatively</u> represent the statewide EE potential when scaled up based on statewide customer counts, appliance saturations, and other key factors.

We therefore decided to use the Austin Energy EE impact and cost estimates – with appropriate scaling to the ERCOT market level – to identify the best measures for our new expanded EE

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[46] ACEEE's scorecard and state-level EE activity summary can be found here: http://www.aceee.org/state-policy/scorecard.

[47] See R. Neal Elliot et al., "Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs," ACEEE Report No. E073, March 2007.  Also, Itron, "Assessment of the Feasible and Achievable Levels of Electricity Savings from Investor Owned Utilities in Texas: 2009-2018," prepared for the PUCT, December 23, 2008.

[48] DNV KEMA, "Austin Energy DSM Market Potential Assessment," June 25, 2012.

[49] Based on EIA-861 data.

[50] There are a number of factors beyond DSM programs that could contribute to this difference (e.g., average home size, market saturation of central air-conditioning).  But the stark difference is consistent with our observation about a higher degree of EE activity in Austin relative to the rest of the state.

portfolio, recognizing that our final statewide estimates are likely conservative relative to ERCOT's total potential. Based on a review of the costs and impacts of a broad range of EE measures in the Austin Energy study, and cross-checking those results against the older statewide assessments, we identified the following as low-cost programs with significant potential for energy efficiency improvement in Texas:

- **Residential cooling efficiency**. Cooling is identified as the residential end use with the largest amount of economic potential, according to the Austin Energy study. Specific measures in this program would include early replacement and upgrades of room and central air-conditioners, improvements in A/C maintenance, incentives for ceiling fans, and proper sizing of standard air-conditioner installations. The program would require a combination of rebates and educational outreach.

- **Commercial indoor lighting efficiency**. Austin Energy identified indoor lighting as the commercial end-use with the most potential for cost-effective energy savings. The program consists of measures such as rebates for a range of more efficient lighting technologies (e.g., T-5, CFLs, LEDs), continuous dimming fixtures, occupancy sensors, and delamping.

- **Industrial pumping efficiency**. While industrial customers are currently exempt from TDSP EE initiatives, we felt it would be worthwhile to include an industrial program to identify the degree to which there is untapped potential for efficiency improvements in this sector. Improved pump efficiency was one of the largest industrial sector EE measures in the Austin Energy study and it is one of the largest sources of load among industrial customers in ERCOT. Specific measures in this program include improved pump operations and maintenance, enhanced pump control strategies, pump system optimization, and improved sizing.

After vetting these programs with industry experts in the state, we established them as the expanded EE portfolio for our study. Similar to our development of the new portfolio of DR options, our expanded EE portfolio is not intended to represent the maximum amount of new EE that could be cost-effectively achieved in ERCOT. Instead, we have chosen a limited portfolio of options that illustrate what could be achieved through a modest and plausible increase in EE activity across the state.

The Austin Energy study reported an estimate of the levelized cost ($/MWh) and impact (MW and GWh) for each EE measure in our portfolio. The costs were taken as given in our study and only updated using a higher discount rate since, as a municipally owned utility, Austin Energy has access to cheaper capital than an investor-owned utility. The impacts were scaled from Austin Energy's customer base to an ERCOT-wide estimate using a number of key scaling factors:

- Residential cooling efficiency potential was scaled based on the relationship between residential air-conditioning electricity consumption in Austin Energy's service territory and in the ERCOT market (ERCOT's total residential electricity

consumption is roughly 22 times larger than Austin Energy's, and the percentage share of residential sales attributable to cooling is slightly higher in ERCOT than in Austin).[51]

- Commercial lighting efficiency potential was scaled based on the relationship between commercial lighting electricity consumption in Austin Energy's service territory and in the ERCOT market (ERCOT's total commercial electricity consumption is roughly 13 times larger than Austin Energy's, and the share of commercial sales attributable to lighting is roughly the same between ERCOT and Austin).[52]

- Industrial pumping efficiency potential was scaled based on the relationship between industrial pumping electricity consumption in Austin Energy's service territory and in the ERCOT market (ERCOT's total industrial electricity consumption is roughly 12 times larger than Austin Energy's, and the percentage share of industrial sales attributable to pumping is more than twice as high in ERCOT).[53]

Further scaling of the impacts was needed to account for achievable participation in the EE programs. The measure-level EE impacts reported in the Austin Energy study represent economic potential and assume that all eligible customers would participate in an EE measure if cost-effective to do so. However, in practice, only a fraction of these customers choose to participate.[54] We assumed that incentives provided to participants in the EE program would equal 75 percent of the incremental cost of the measure. Based on relationships derived from the Austin Energy study at this incentive level, we accounted for achievable participation in the EE programs by reducing the residential impacts by 64 percent and the commercial and industrial impacts by 47 percent.[55]

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[51] To develop these estimates, we relied on data from Austin Energy's Annual Performance Report (July 26, 2013), EIA-861 data, Austin Energy's 2012 EE potential study, and Itron's 2008 statewide assessment of EE potential.

[52] To develop these estimates, we relied on data from Austin Energy's Annual Performance Report (July 26, 2013), EIA-861 data, Austin Energy's 2012 EE potential study, and the EIA's Commercial Buildings Energy Consumption Survey (CBECS) (last updated in 2003).

[53] To develop these estimates, we relied on data from Austin Energy's Annual Performance Report (July 26, 2013), EIA-861 data, Austin Energy's 2012 EE potential study, and Itron's 2008 statewide assessment of EE potential.

[54] There are a variety of reasons that customers may choose not to participate in an energy efficiency program when it is in their financial interest to do so. One of the biggest reasons is that customers are observed to place little value on the future financial benefits of EE – that is to say that they heavily discount the value of future savings when making energy efficiency investment decisions.

[55] Based on the relationship of achievable and economic potential in Table 5-5 (page 5-73) of the Austin Energy study.

The programs were assumed to be offered beginning in 2016, with a five year ramp-up in participation reaching full achievable enrollment by 2020. We use an S-shaped curve (also referred to as a Bass diffusion curve) to represent a nonlinear increase commonly observed in new product adoption. After 2020, the energy impacts of the EE programs are assumed to grow at the same annual rate as total electricity sales in ERCOT. The peak impacts of the EE portfolio grow at our projected ERCOT peak demand growth rate. The general implication of this assumption is that, as new customers join the system, they participate in the energy efficiency measures in the same proportion as the entire population.

The resulting impact of our expanded EE portfolio on the ERCOT energy forecast is shown in Figure V-1. For reference, this figure also includes ERCOT's 2014 forecast (which is a "frozen efficiency" case) and Brattle's adjusted baseline forecast accounting for known/planned efficiency improvements, as discussed in Chapter III. The average annual growth in energy drops from 1.7 percent in ERCOT's frozen efficiency case to 1.4 percent after accounting for known/planned EE, and drops further to 1.3 percent when also including the impact of our expanded EE portfolio.

### Figure V-1: Projected Annual Electricity Consumption in ERCOT
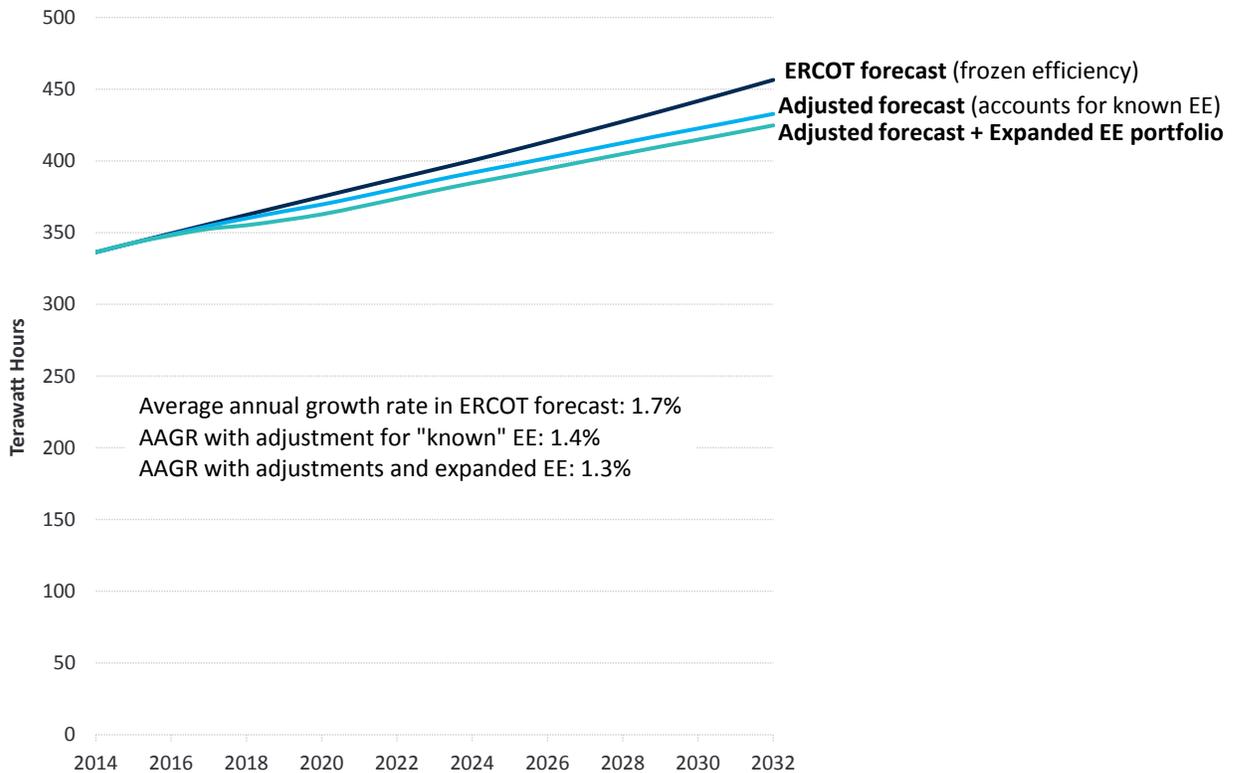


Sources: *2014 Annual Energy Outlook Table 73 and 2014 ERCOT Long Term Hourly Peak Demand and Energy Forecast*

The impact of EE on the peak demand forecast is shown in Figure V-2 below. The peak impact of the EE measures is disproportionately higher than the energy impact. This is not surprising, as the end-uses that are targeted by our expanded EE portfolio – residential cooling and commercial

lighting in particular – are used more during peak hours than off-peak hours (e.g., lights in commercial buildings are turned on primarily during normal business hours).

**Figure V-2: Projected Annual Peak Demand in ERCOT**
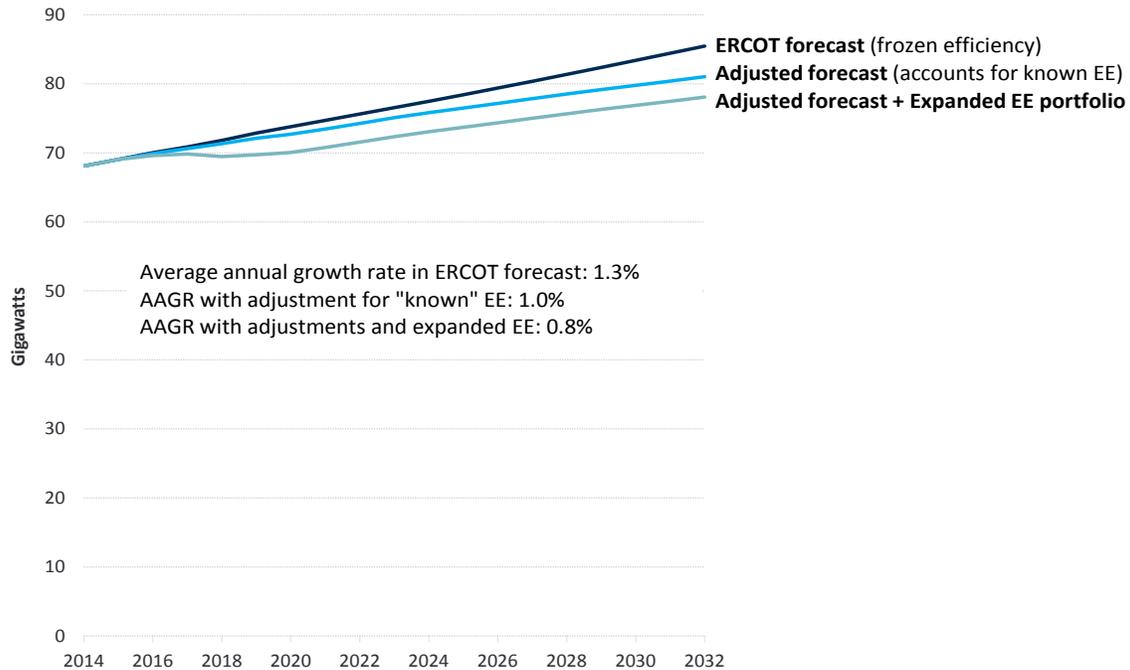


ERCOT forecast (frozen efficiency)
Adjusted forecast (accounts for known EE)
Adjusted forecast + Expanded EE portfolio

Average annual growth rate in ERCOT forecast: 1.3%
AAGR with adjustment for "known" EE: 1.0%
AAGR with adjustments and expanded EE: 0.8%

*Sources: 2014 Annual Energy Outlook Table 73 and 2014 ERCOT Long Term Hourly Peak Demand and Energy Forecast*

The peak impacts of EE are particularly relevant to our study, because they have direct implications for the amount of new capacity that will be added across the forecast horizon. Figure V-3 illustrates the reduction in peak demand growth attributable to EE. In ERCOT's 2014 frozen efficiency forecast and in our Phase II study, peak demand was projected to grow by 17 GW between 2014 and 2032. In contrast, our adjustments to the peak forecast for known/planned efficiency improvements reduces total growth to 13 GW, a reduction of 4 GW. Including the impacts of our expanded EE portfolio further reduces peak growth to 10 GW. This is a 7 GW (or 41 percent) reduction in peak growth relative to ERCOT's frozen efficiency case. These estimates do not account for the impact of DR or CHP – those are incremental to these impacts.

## Figure V-3: Total ERCOT Peak Demand Growth, 2014 - 2032
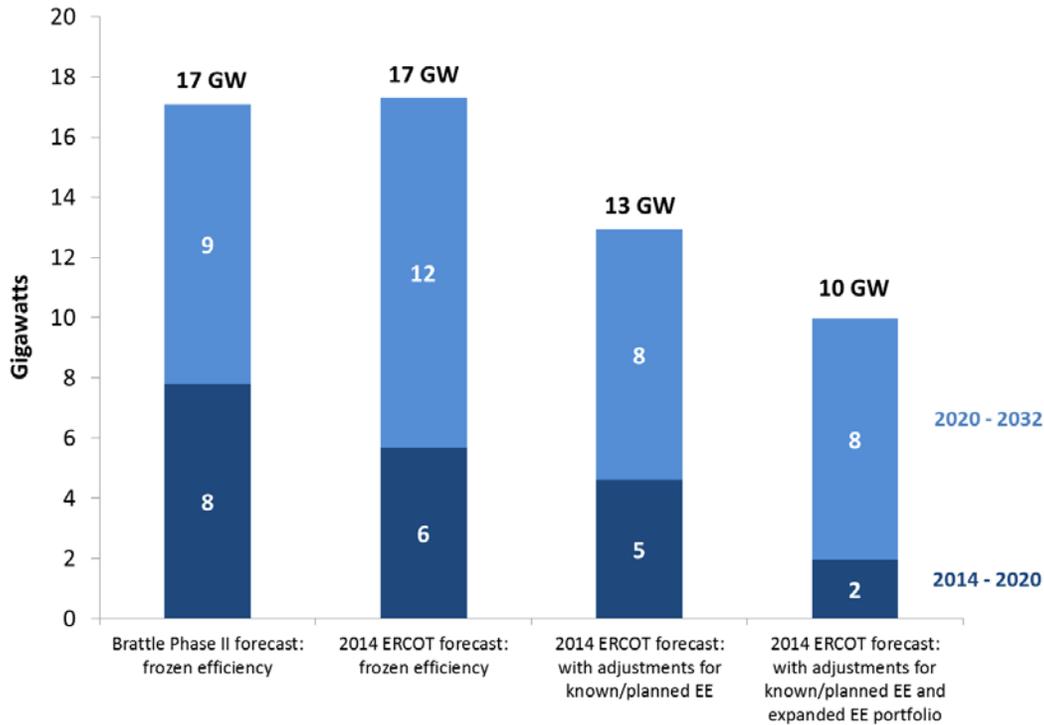


While the Austin Energy study found the measures included in our expanded EE portfolio to be cost-effective, it was necessary to confirm that they would be cost-effective under the new price projections in our study. We relied on the Utility Cost Test (also known as the Program Administrator Test) to assess the cost-effectiveness of the portfolio, as this is the established framework that is utilized by the PUCT in evaluating the TDSP EE programs. The Utility Cost Test measures cost-effectiveness from the perspective of the utility or third party administrator. It includes, as benefits to the utility, avoided energy costs (fuel and variable O&M, which are represented in the energy market prices) and avoided capacity costs (generating capacity and transmission and distribution capacity). Costs are those which would be borne by the utility or a third party administrator, such as incentive payments (assumed in our study to be 75 percent of the total incremental cost of the measure) and administrative overhead.

The total portfolio passes the cost-effectiveness screen purely on the basis of avoided energy market costs in all scenarios analyzed in our study. At the individual program level, the benefit-cost ratio of the residential cooling efficiency program drops below 1.0 in three of the four scenarios. Including a very modest avoided T&D capacity cost assumption of $20/kW-year is enough for the residential program to be cost-effective across all scenarios. The commercial and industrial programs are cost-effective under all scenarios based purely on avoided energy market costs.

It was necessary to establish an hourly shape for the EE impacts in order to accurately represent them in our market simulation models. For each residential and commercial EE measure, we

relied on hourly shapes from the California Public Utilities Commission's Database for Energy Efficient Resources (DEER).[56] Since DEER data does not exist for industrial EE measures, we relied on hourly industrial load data separately published by the California utilities.[57] The ERCOT-wide annual energy impacts were scaled using these hourly shapes, while the ERCOT-side peak impacts were not altered and were applied to the top 100 load hours of the year. The result is an hourly shaped EE impact profile that maintains the proportional relationship between peak and energy in the Austin Energy study. These shaped impacts were applied as adjustments to the load forecast before running our market simulation models.[58]

The total impact of our expanded EE portfolio represents a significant incremental increase over known/planned efficiency improvements during the same period. Between 2014 and 2032, we estimate that the impact of the state mandated savings target – if it remains unchanged – will reduce electricity consumption by 2.1 percent (incremental to the future impact of known codes and standards). Our expanded portfolio would incrementally reduce this further by 1.8 percent, resulting in a total efficiency reduction of 3.9 percent. By comparison, the 2008 PUCT study conducted by Itron identified 6.8 percent of achievable statewide annual energy savings potential over a 10 year period. The 2012 Austin Energy study identified 9.8 percent achievable annual energy savings potential in the Austin market over a nine year period. And, in 2007, ACEEE identified 11 percent achievable annual energy savings potential statewide over a 15 year period. These results are summarized in Figure V-4.

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[56] The publicly available DEER database is a commonly utilized resource in EE studies. The data and accompanying documentation can be found at: http://www.deeresources.com/. In future studies, Texas-specific data from The Pecan Street Project could be commercially licensed to further refine these estimates.

[57] California utilities keep up-to-date hourly load profiles for each customer class for the purpose of hourly billing: http://www.sdge.com/customer-choice/customer-choice/dynamic-load-profiles

[58] The hourly impacts were averaged by day type (weekday, weekend), time period (peak, mid-peak, off-peak), and season before modifying the ERCOT load forecast.

Figure V-4: Achievable ERCOT Energy Savings Potential Estimates
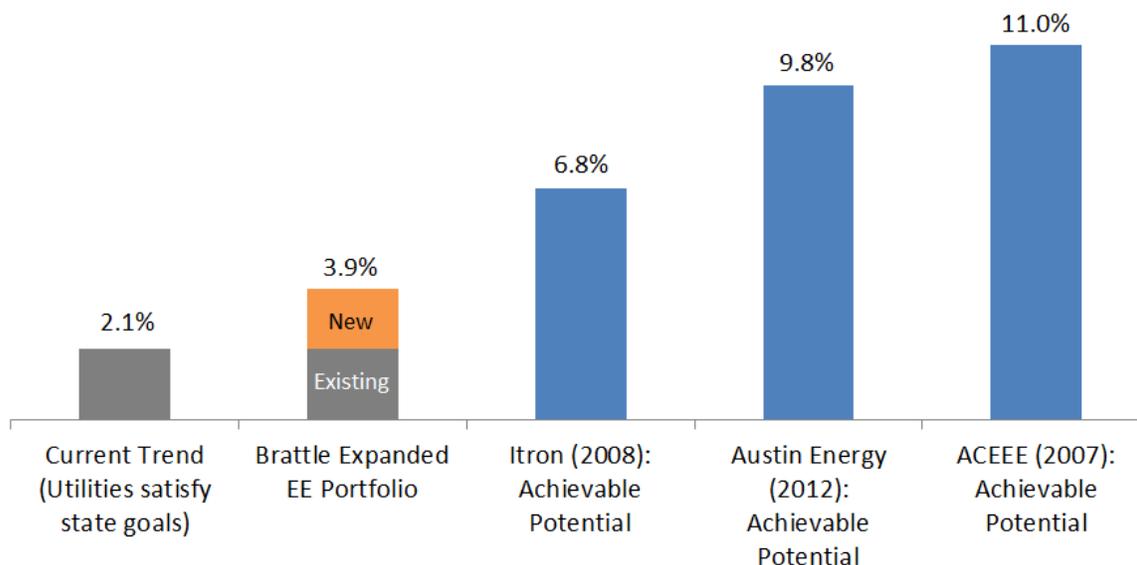
Notes:
*Impact of existing EE assumes state target is exactly met in each year*
*Impacts in the potential studies are annual impacts for the final year of their respecive forecasts.*
*The impact of our expanded DR portfolio is shown for 2020*
*Each estimate is incremental to a baseline projection that accounts for known/planned efficiency improvements*

This comparison of efficiency studies highlights the conservative nature of our expanded EE portfolio. It also points to the need for a new, bottom-up assessment of EE and DR market potential in the state. Other than the 2012 Austin Energy study, which is focused specifically on that utility's service territory, no comprehensive statewide assessment of demand-side efficiency opportunities have been conducted to our knowledge in the past six years. We are approaching the end of the forecast horizon of the older studies, and much has changed in the industry and the economy since they were conducted. An updated study identifying the new demand-side opportunities and challenges in Texas would contribute significant value in future planning and policy development activities in the state.

# VI. Development of Assumptions for Combined Heat and Power in ERCOT

## A. OVERVIEW OF CHP STATUS IN TEXAS

Combined Heat and Power (CHP), also known as cogeneration, is a technology that produces electricity and thermal energy simultaneously in an integrated system. CHP achieves higher overall efficiency than separately generating electricity and heat, and thus reduces the cost of meet electricity and thermal needs. As a result, it typically also leads to lower air emission rates for carbon and other pollutants including $SO_2$ and $NO_x$. The efficiency of a CHP system can reach 75% or more, depending on its size and technology. In addition, as a form of distributed generation, CHP systems can reduce the investment required for transmission and distribution, avoid line losses, and improve energy security during grid power failures.

With 17.5 GW of CHP capacity,[59] Texas leads the nation in CHP installations. More than 13 GW out of the 17.5 GW of CHP in Texas is located in ERCOT. As shown in Figure VI-1, the majority of the CHP capacity is located on the Gulf coast, where large CHP facilities dominate. CHP facilities in petrochemical facilities represent over 95% of the installed CHP capacity in Texas.

### Figure VI-1: Distribution of Texas CHP Installed Capacity
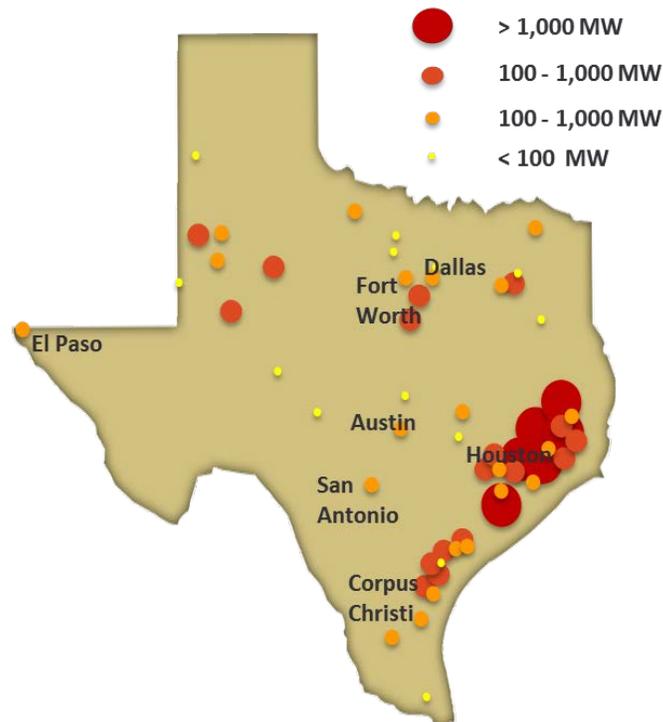


*Source: Combined Heat and Power Installation Database, ICF International*

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[59]    Combined Heat and Power Installation Database, ICF International, http://www.eea-inc.com/chpdata/.

## Figure VI-2: Installed CHP in Texas Capacity by Sector
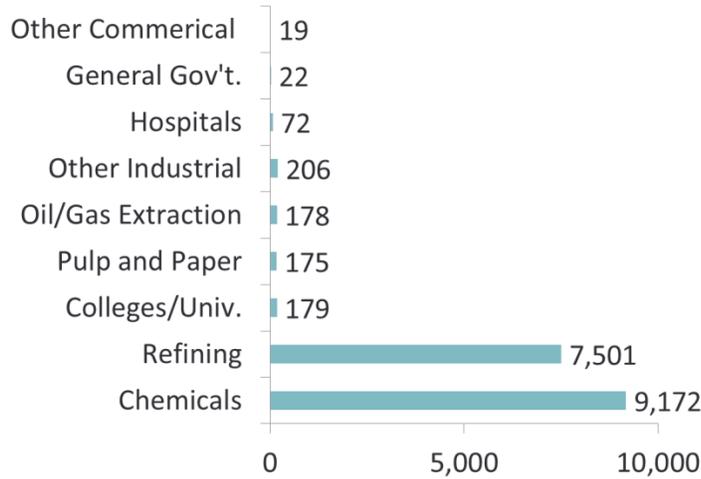


*Source: Combined Heat and Power Installation Database, ICF International*

## B. SCOPE OF ANALYSIS

Since previous research[60] has indicated limited opportunities for CHP applications in the residential and commercial sector, we focused our analysis on the industrial sector. Although there are promising new micro CHP and fuel cell technologies that may become significant in the residential and small commercial sectors, substantial near-term penetration is much more likely in larger commercial and industrial locations. Our own modeling results, presented below, also bear this out.

Combined Cooling, Heat, and Power (CCHP) does not appear to be very promising in Texas, due to the short heating season and the lower efficiency of the cooling technology. Although a technological breakthrough may change the outlook, it is beyond our study scope.

We also limited our analysis on industrial applications with sufficient thermal load to require CHP capacity in excess of 1 MW CHP.

We evaluated the CHP potential for existing industrial facilities as well as for future new industrial facilities based on the industrial growth rates forecasted in the EIA's AEO 2014 for the petrochemical industry and Texas' historical growth rates for other industrial sectors.

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[60] Combined Heat and Power in Texas: Status, Potential, and Policies to Foster Investment, Summit Blue, 2008.

## C. EVALUATION OF THE TECHNICAL POTENTIAL FOR CHP IN ERCOT

Figure VI-3 shows our process for evaluating the technical potential for CHP in ERCOT. In Step 1, we start by estimating the thermal load of a potential industrial CHP host since we assumed that CHP capacity would be sized based on the average thermal load of an industrial host. Step 2 evaluates the costs and characteristics of CHP technologies by type of technology. In Step 3, we size the CHP plant for each potential CHP host based on the thermal load and the characteristics of various CHP technologies. Aggregation of the CHP capacity for all potential hosts results in a total CHP potential in ERCOT for existing industrial facilities. To evaluate the untapped technical potential for existing industrial facilities, we subtract the CHP facilities already installed. We further adjust this figure based on industrial growth rates to account for the opportunity for future new industrial facilities. We discuss the details of each step in more detail below.

**Figure VI-3: Process flow chart to evaluate CHP technical potentials in ERCOT**
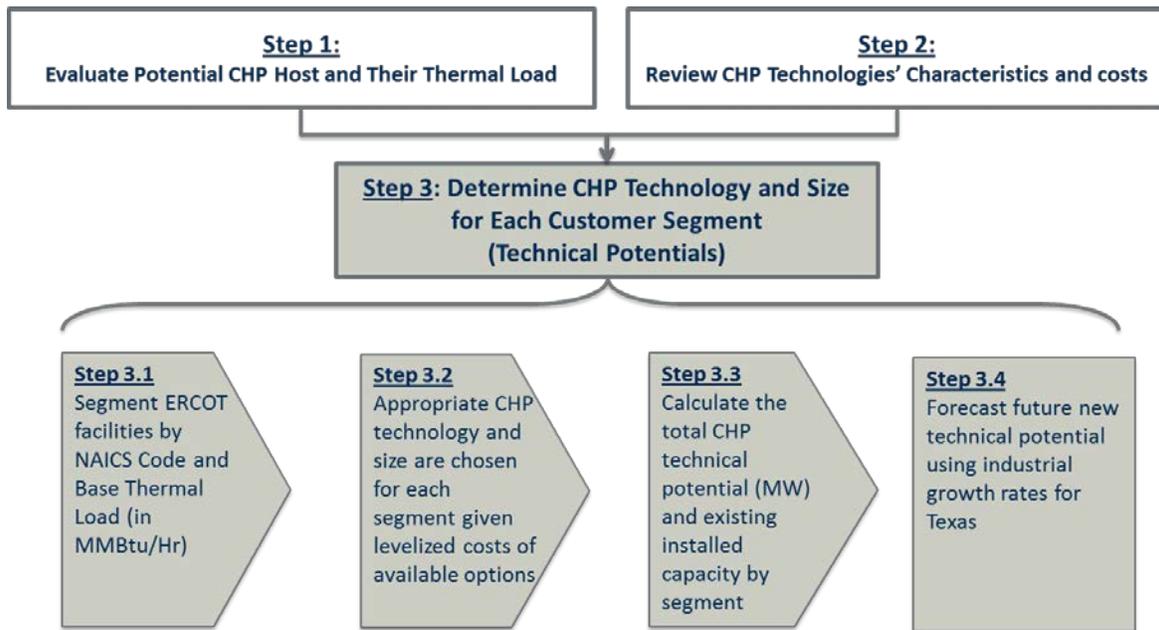


### 1. Evaluate Potential CHP Hosts and Their Thermal Load

We use two data sources to estimate the thermal load for potential CHP hosts in the industrial sectors: EIA's Manufacturing Energy Consumption Survey (MECS) data from 2010,[61] which provides data on the annual electric load and natural gas consumption as a fuel (not as a feedstock), which we use as a proxy for thermal need, for North American Industry Classification

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[61] http://www.eia.gov/consumption/manufacturing/data/2010/.

System (NAICS) sectors for the South region as shown in Table VI-1. The other is the Country Business Patterns (CBP) published by the U.S. Census Bureau,[62] which includes the number of employees and facilities by NAICS sector and county in Texas and the South region. Based on these two sets of data, we calculate the average annual electric load and the average annual thermal load per employee in the South region. Then we multiply both by the number of employees of the industrial facilities in counties that belong to ERCOT to obtain an estimated annual thermal load and electric load for these facilities. The annual thermal load is divided by the annual operation hours for each facility, resulting in a thermal base load in MMBtu/hr, on which the size of CHP capacity is based.

### Table VI-1: List of Industries Evaluated for CHP Potential in ERCOT by NAICS Code and Their Operating Hours

| NAICS Code | NAICS Category | Annual Operating Hours |
|---|---|---|
| 311 | Food Manufacturing | 7,500 |
| 312 | Beverage and Tobacco Product Manufacturing | 7,500 |
| 313 | Textile Mills | 7,500 |
| 314 | Textile Product Mills | 7,500 |
| 315 | Apparel Manufacturing | 7,500 |
| 316 | Leather and Allied Product Manufacturing | 7,500 |
| 321 | Wood Product Manufacturing | 7,500 |
| 322 | Paper Manufacturing | 7,500 |
| 323 | Printing and Related Support Activities | 7,500 |
| 324 | Petroleum and Coal Products Manufacturing | 8,300 |
| 325 | Chemical Manufacturing | 8,300 |
| 326 | Plastics and Rubber Products Manufacturing | 8,300 |
| 327 | Nonmetallic Mineral Product Manufacturing | 7,500 |
| 331 | Primary Metal Manufacturing | 7,500 |
| 332 | Fabricated Metal Product Manufacturing | 7,500 |
| 333 | Machinery Manufacturing | 7,500 |
| 334 | Computer and Electronic Product Manufacturing | 7,500 |
| 335 | Electrical Equipment, Appliance, and Component Manufacturing | 7,500 |
| 336 | Transportation Equipment Manufacturing | 7,500 |
| 337 | Furniture and Related Product Manufacturing | 7,500 |
| 339 | Miscellaneous Manufacturing | 7,500 |

*Sources and notes:*
*Annual operating hours are based on EPA Combined Heat and Power Partnership* http://www.epa.gov/chp/
*with the exceptions of petroleum, chemicals, and rubber industries, for which adjustments are made based*
*on experts' recommendation.*

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[62]   http://www.census.gov/econ/cbp/

## 2. Review of CHP Technologies' Characteristics and Costs

Different technologies have different costs and technical performance when applied to CHP facilities. To determine the costs and performance of CHP technologies, we reviewed technical papers, research, and studies related to CHP technologies. Table VI-2 summarizes the characteristics and costs for these different technologies. Most of the terms have the same definitions as those used for conventional power generation technologies, with two specific terms for CHP technologies: (1) the E/T ratio is the ratio between the electric output and thermal output for a CHP process; and (2) the net heat rate which is used to account for the fuel consumption of a CHP plant only for generating electricity, to provide an equivalent comparison to other power generation technologies. This is why it is also referred to as "Fuel Charged to Power." It is calculated as the total fuel input to the CHP system – minus the fuel that would normally be used to generate the same amount of thermal output as the CHP system output), divided by the CHP electric output.

### Table VI-2: Summary of CHP Technologies' Characteristics and Costs

| CHP Size | Technology Type | Capital (2012$/ kW) | FOM (2012$/kW-yr) | VOM (2012$/MWh) | Heat Rate (Btu/kWh) | Net Heat Rate (Btu/kWh) | E/T Ratio | Lifetime (years) | Availability (%) | Levelized Cost (2012$ per MWh) |
|---|---|---|---|---|---|---|---|---|---|---|
| 0.5 MW | Reciprocating Engine | $2,017 | $7.28 | $15.60 | 9,866 | 4,470 | 0.79 | 20 | 95% | $115.50 |
| | Microturbine | $2,537 | $0.02 | $22.00 | 13,080 | 6,882 | 0.69 | 10 | 89% | $145.34 |
| | Fuel Cell | $5,803 | $0.00 | $36.40 | 8,022 | 6,022 | 2.13 | 10 | 80% | $199.14 |
| 1 MW | Gas Turbine | $3,457 | $41.60 | $6.24 | 16,047 | 7,013 | 0.47 | 20 | 95% | $178.68 |
| | Reciprocating Engine | $1,705 | $5.20 | $12.48 | 9,760 | 4,385 | 0.79 | 20 | 95% | $103.62 |
| 5 MW | Gas Turbine | $1,799 | $10.40 | $6.24 | 12,312 | 5,839 | 0.66 | 20 | 95% | $113.59 |
| | Reciprocating Engine | $1,175 | $1.56 | $9.36 | 8,758 | 4,950 | 1.12 | 20 | 95% | $81.64 |
| 10 MW | Gas Turbine | $1,350 | $7.80 | $6.24 | 12,001 | 6,007 | 0.71 | 20 | 95% | $100.01 |
| 40 MW | Gas Turbine | $1,011 | $5.20 | $3.64 | 9,220 | 5,180 | 1.06 | 20 | 95% | $74.90 |
| 300 MW | Combined-Cycle | $891 | $11.44 | $3.12 | 6,736 | 4,500 | 1.06 | 20 | 95% | $60.10 |

*Source and notes:*
*US EPA, "Catalogue of CHP Technologies", December 2008; Summit Blue Consulting, "Combined Heat and Power in Texas", December 10, 2008; Cogeneration Application Considerations, May 2009, General Electric; Brattle Analysis.*

We categorize CHP technologies in terms of the sizes, for which these technologies are typically applied in CHP facilities, and also calculate levelized costs based on capital costs, fixed operating and maintenance costs (FOM), variable operating and maintenance costs (VOM), and heat rate, which are used to determine the dominant CHP technology for a potential CHP host in a particular range. For example, a reciprocating engine is the dominant technology for CHP between 1 MW and 5 MW based on the levelized cost while gas turbines become more competitive for larger systems. For industrial facilities with thermal load large enough to require a few hundred megawatt system, a combined cycle CHP system, *i.e.,* gas turbines coupled with steam turbines, becomes more economically efficient than simple gas turbine CHP systems. This result is consistent with the competitive market sizes for different CHP technologies in the literature, as is shown in Figure VI-4.

## Figure VI-4: Technology Size Coverage
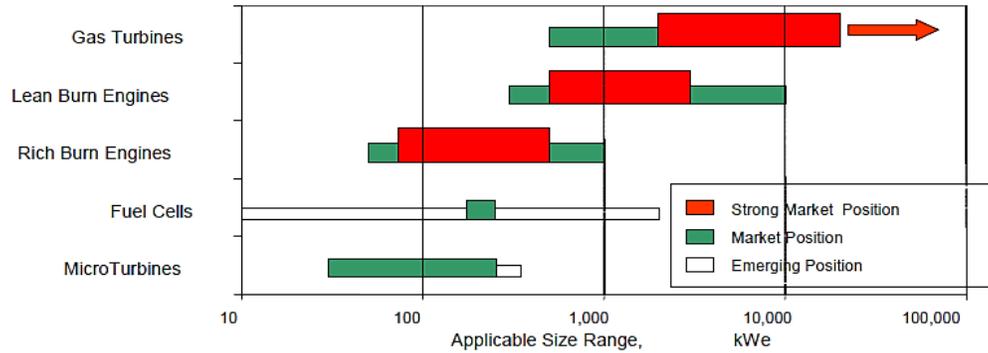
## 3. Determine CHP Technical Potential in ERCOT

Based on the thermal load of potential CHP hosts evaluated in Step 1 and the cost and technical characteristics of CHP technologies evaluated in Step 2, we estimate the technical potential for CHP in ERCOT in four steps, as shown in Figure VI-3 and described below:

3.1 Segment ERCOT facilities by NAICS Code and base thermal load (in MMBtu/Hr)

In each NAICS industry, there are different levels of thermal loads depending on the size of the firm, characterized by the number of employee in this analysis. Because the level of base thermal load is the key factor determining CHP technology type and size, each industry is further segmented based on the level of base thermal load in MMBtu/hr into categories of 5-10 MMBtu/hr, 10-20 MMBtu/hr, 20-50 MMBtu/hr, 50-100 MMBtu/hr, 100-500 MMBtu/hr, and >500 MMBtu/hr.

3.2 Chose appropriate CHP technology and size for each segment given levelized costs of available options

Then for each segment, appropriate CHP technology and size is chosen for each segment to meet the thermal load given levelized costs of available options, as discussed in the section above. For example, a reciprocating engine is selected for the segment with 5-10 MMBtu/hr since this level of thermal base load implies that the size of the CHP system is under 5 MW. Similarly, gas turbines are selected for the segment with 50-100 MMBtu/hr. Combined cycle CHP is selected for the largest thermal load category.

3.3 Calculate the total CHP technical potential (MW) for existing industrial facilities in ERCOT

Summing up all CHP potential capacity for all firms in each segment leads to the total CHP technical potential in existing industrial facilities in ERCOT, as shown in Table VI-3:

### Table VI-3: Total CHP Technical Potential in Existing Industrial Facilities in ERCOT

| NAICS Code | NAICS Category | By CHP Unit Size (MW) | | | | Total |
|---|---|---|---|---|---|---|
| | | 1 - 5 | 5 - 20 | 20 - 100 | > 100 | |
| 311 | Food Manufacturing | 394 | 180 | 0 | 0 | 573 |
| 312 | Beverage and Tobacco Product Manufacturing | 25 | 47 | 0 | 0 | 72 |
| 313 | Textile Mills | 10 | 0 | 0 | 0 | 10 |
| 314 | Textile Product Mills | 0 | 0 | 0 | 0 | 0 |
| 315 | Apparel Manufacturing | 0 | 0 | 0 | 0 | 0 |
| 316 | Leather and Allied Product Manufacturing | 0 | 0 | 0 | 0 | 0 |
| 321 | Wood Product Manufacturing | 5 | 0 | 0 | 0 | 5 |
| 322 | Paper Manufacturing | 221 | 279 | 41 | 0 | 541 |
| 323 | Printing and Related Support Activities | 3 | 0 | 0 | 0 | 3 |
| 324 | Petroleum and Coal Products Manufacturing | 199 | 204 | 1,043 | 4,637 | 6,083 |
| 325 | Chemical Manufacturing | 1,091 | 922 | 3,911 | 3,599 | 9,524 |
| 326 | Plastics and Rubber Products Manufacturing | 22 | 68 | 0 | 0 | 90 |
| 327 | Nonmetallic Mineral Product Manufacturing | 356 | 96 | 47 | 0 | 499 |
| 331 | Primary Metal Manufacturing | 103 | 410 | 250 | 0 | 764 |
| 332 | Fabricated Metal Product Manufacturing | 82 | 0 | 0 | 0 | 82 |
| 333 | Machinery Manufacturing | 39 | 6 | 0 | 0 | 45 |
| 334 | Computer and Electronic Product Manufacturing | 28 | 22 | 0 | 0 | 50 |
| 335 | Electrical Equipment, Appliance, and Component Manufacturing | 26 | 8 | 0 | 0 | 34 |
| 336 | Transportation Equipment Manufacturing | 41 | 39 | 0 | 0 | 80 |
| 337 | Furniture and Related Product Manufacturing | 0 | 0 | 0 | 0 | 0 |
| 339 | Miscellaneous Manufacturing | 0 | 0 | 0 | 0 | 0 |
| Total | | 2,645 | 2,280 | 5,292 | 8,236 | 18,454 |

The total CHP technical potentials above for each segment include the existing installed capacity. Therefore, with the exception of petroleum and coal products manufacturing and chemical manufacturing, to get the untapped CHP technical potential for each segment, we subtract the capacity of existing CHP facilities. These two industries have very high and constant base thermal loads, and require large gas turbine or combined cycle units. In these facilities, the CHP capacity are likely to be oversized so that they can sometimes operate as conventional combined cycle units to sell into the grid in excess of the thermal load. These facilities are often developed and operated by Independent Power Producers. Our estimate of the technical potential does not reflect the oversized capacity. Therefore, instead of subtracting the

existing CHP capacity for the segment larger than 100 MW from the total potential in this segment, we estimated the untapped CHP potential for the petrochemical industry based on the percentage of industrial facilities that do not currently have CHP installed. We then aggregate all the industries into two main categories: petrochemical industry and other. We estimate the potentials in future years based on industrial growth rates, as described in Step 3.4 below. The untapped CHP potential in existing industrial facilities is shown in Table VI-4 below:

**Table VI-4: Untapped CHP Technical Potential for Existing Industrial Facilities in ERCOT**

|  | By CHP Unit Size (MW) | | | | |
| --- | --- | --- | --- | --- | --- |
| Category | 1 - 5 | 5 - 20 | 20 - 100 | > 100 | Total |
| PetroChem | 1,280 | 1,094 | 4,196 | 2,059 | 8,629 |
| Other | 1,346 | 1,154 | 212 | 0 | 2,713 |
| Total | 2,626 | 2,248 | 4,408 | 2,059 | 11,341 |

3.4 Forecast future new CHP technical potential using industrial growth rates for ERCOT

To estimate the total CHP technical potential for all industrial sectors in ERCOT in future years, we grow the total CHP technical potential in existing industrial facilities with future industrial growth rates. For industries other than petrochemical industry, we applied the historical annual industrial output growth rate for Texas from 2006-2011 as published by the Bureau of Economic Analysis. Since we were not able to obtain Texas-specific future growth rates, we applied the national average industrial growth rates for the petrochemical industry as forecasted in EIA's AEO 2014.[63] The growth rates relative to 2010, which is the base year for which we have the MECS data and CBP data, are summarized in Table VI-5 for 2017, 2022, and 2032.

**Table VI-5: Industrial Growth Rates As Compared to 2010**

|  | 2017 | 2022 | 2032 |
| --- | --- | --- | --- |
| PetroChem | 11.91% | 26.02% | 44.04% |
| Others | 8.27% | 14.59% | 28.37% |

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[63] EIA AEO 2014, Table 20, Industrial Sector Macroeconomic Indicators, United States, Reference Case.

We then subtracted the existing CHP capacity similar to what is described in Step 3.3, to get the future new CHP technical potential.  The results are shown in Table VI-6, Table VI-7, and Table VI-8.

**Table VI-6: Future New CHP Technical Potentials in 2017 in ERCOT**

| Category | By CHP Unit Size (MW) | | | | |
| | 1 - 5 | 5 - 20 | 20 - 100 | > 100 | Total |
| --- | --- | --- | --- | --- | --- |
| PetroChem | 475 | 2,213 | 7,753 | 2,304 | 12,745 |
| Other | 1,491 | 1,220 | 362 | 0 | 3,073 |
| Total | 1,966 | 3,433 | 8,115 | 2,304 | 15,818 |

**Table VI-7: Future New CHP Technical Potentials in 2022 in ERCOT**

| Category | By CHP Unit Size (MW) | | | | |
| | 1 - 5 | 5 - 20 | 20 - 100 | > 100 | Total |
| --- | --- | --- | --- | --- | --- |
| PetroChem | 535 | 2,494 | 8,799 | 2,595 | 14,423 |
| Other | 1,578 | 1,291 | 383 | 0 | 3,253 |
| Total | 2,113 | 3,785 | 9,182 | 2,595 | 17,675 |

**Table VI-8: Future New CHP Technical Potentials in 2032 in ERCOT**

| Category | By CHP Unit Size (MW) | | | | |
| | 1 - 5 | 5 - 20 | 20 - 100 | > 100 | Total |
| --- | --- | --- | --- | --- | --- |
| PetroChem | 611 | 2,853 | 10,135 | 2,966 | 16,565 |
| Other | 1,768 | 1,447 | 430 | 0 | 3,645 |
| Total | 2,379 | 4,300 | 10,565 | 2,966 | 20,210 |

This future technical potential is provided as an input to the Xpand model, which then determines the CHP that can be economically built, given the existing generation system, future loads, fuel prices, and competing new technologies.

# VII. Results and Discussion

Our previous ("Phase II") simulations of the ERCOT market, published in December 2013, serve as a natural reference point for our new "Phase III" results. With this in mind, it is useful to recall that the following aspects of our simulation have changed between Phases II and III:

- Natural gas prices have increased slightly in both our base and high gas price case (see Figure III-3). This would be expected to slightly increase renewable and DR additions, *ceteris paribus*.

- The underlying forecast for load and sales growth has been changed from the original ERCOT load and sales forecast used in Phase II to a forecast in this Phase that is based on an April 2014 updated ERCOT forecast that we adjusted to account for existing energy efficiency programs and federal standards not accounted for in ERCOT's forecast. As a result, the Phase III reference case load forecast is lower than the Phase II forecast by 6 GW (7 percent) by the end of the forecast horizon. The Phase III sales forecast is slightly lower than the Phase II sales forecast through 2025 (by around 2 percent on average) after which it is slightly higher (less than 1 percent). It is worth restating that the decline in peak load and sales between Reference cases exceeds the additional sales reductions we project in our expanded-EE scenarios in Phase III.

- Demand response programs have been modeled much more comprehensively than in Phase II, resulting in substantial added opportunities to employ DR. While this would be expected to increase the market's use of DR, the original DR in our Phase II simulations was treated as a very low-cost resource and therefore may have been over-used in some cases. These methodological issues were discussed in Section B in Chapter II.

- A required reserve margin mechanism (similar, but not the same as, a capacity market) is not included in any Phase III scenario, but was assumed in most Phase II scenarios. This returns the market to an energy-only market with energy prices that are more sensitive to capacity changes than in most Phase II scenarios, which had required reserve mechanisms.

- In the scenarios in which it is employed, energy efficiency reduces load growth, displacing new capacity additions, but the precise capacity the market would choose not to build is uncertain.

When comparing the results of the two phases of our work it is worth keeping in mind that the differences between the scenarios are the composite result of all of these changes and their interactions. In particular, the new base case load forecast and expanded DR and EE have the effect of significantly increasing the annual load factor, also known as "flattening the peaks" in hourly loads over the year. A flatter load profile tends to make high-load-factor resources, which in this case includes Panhandle/NW wind plants as well as gas CCGTs, more cost-effective.

Similarly, when examining the strong federal carbon policy cases it should be noted that these scenarios use the high gas price case, and lower renewables costs than either Reference case, as in Phase II. Changes in the generation mix are the composite result of all these changes.

## A. REFERENCE CASE

Figure VII-1 shows capacity additions for the Phase III Reference case. This case includes the option of market-installed CHP and DR, but does not include the enhanced EE portfolio. Table VII-1 shows the details of capacity additions by type and converged year and Figure VII-2 shows the percentage mix of generation by fuel type across the full period.

### Figure VII-1: Capacity Additions for Phase III Reference Case with New DR and New CHP
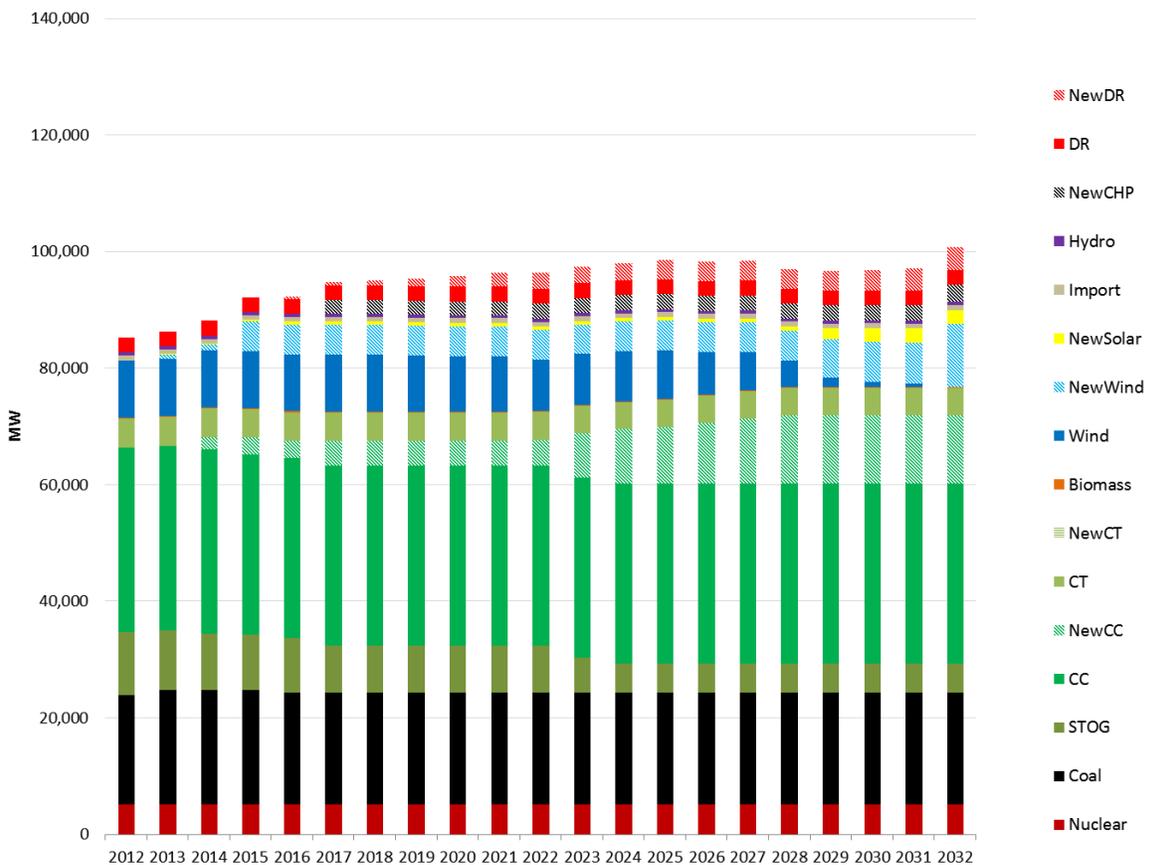
# Table VII-1: Existing and New Generating Resources for Phase III (MW) Reference Case With New DR and New CHP[64],[65]

| | 2012 | 2017 | | | 2022 | | | 2032 | | | Growth, 2012-2032 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Existing | Cumulative Retirements | Cumulative New Builds | Total | Cumulative Retirements | Cumulative New Builds | Total | Cumulative Retirements | Cumulative New Builds | Total | MW | % |
| **Nuclear** | 5,132 | 0 | 0 | 5,132 | 0 | 0 | 5,132 | 0 | 0 | 5,132 | 0 | 0% |
| **Coal** | 18,694 | 395 | 925 | 19,224 | 395 | 925 | 19,224 | 395 | 925 | 19,224 | 530 | 3% |
| **Steam Oil/Gas** | 12,616 | 4,581 | 0 | 8,035 | 4,581 | 0 | 8,035 | 7,747 | 0 | 4,869 | -7,747 | -61% |
| **Combined-Cycle Gas** | 31,644 | 743 | 4,186 | 35,087 | 743 | 4,186 | 35,087 | 743 | 11,402 | 42,303 | 10,659 | 34% |
| **Combustion Turbine Gas** | 4,833 | 156 | 0 | 4,677 | 230 | 0 | 4,603 | 454 | 0 | 4,379 | -454 | -9% |
| **Internal Combustion Gas** | 243 | 0 | 0 | 243 | 0 | 0 | 243 | 0 | 0 | 243 | 0 | 0% |
| **Hydro** | 542 | 0 | 0 | 542 | 0 | 0 | 542 | 0 | 0 | 542 | 0 | 0% |
| **Biomass** | 159 | 0 | 0 | 159 | 0 | 0 | 159 | 0 | 0 | 159 | 0 | 0% |
| **Wind** | 9,757 | 40 | 5,119 | 14,836 | 1,008 | 5,119 | 13,868 | 9,757 | 10,818 | 10,819 | 1,062 | 11% |
| **Solar** | 30 | 0 | 532 | 562 | 0 | 532 | 562 | 0 | 2,753 | 2,783 | 2,753 | 9177% |
| **CHP** | | 0 | 2,304 | 2,304 | 0 | 2,595 | 2,595 | 0 | 2,966 | 2,966 | 2,966 | N/A |
| **Demand Response** | 2,547 | 0 | 764 | 3,311 | 0 | 3,307 | 5,854 | 0 | 3,812 | 6,359 | 3,812 | 150% |
| **TOTAL** | 86,197 | 5,915 | 13,830 | 94,112 | 6,957 | 16,664 | 95,903 | 19,096 | 32,676 | 99,777 | 13,580 | 16% |

Overall, the Phase III reference case shows greater penetration of wind power facilitated by higher gas prices and the higher system load factor discussed above. ERCOT adds 1 net GW of wind capacity by 2032, compared to a 5.3 GW wind capacity reduction in the Phase II reference by 2032.[66] Nearly all this new wind is built in the final three years of the simulation, when wind becomes more competitive per MWh with power from CCGTs.

Conversely, there is significantly less CCGT and solar PV construction in the Phase III Reference case than in the Phase II, though for different reasons. Phase III CCGT net additions are 10.7 GW by 2032, 10.6 GW less than the Phase II reference. This is due primarily to the lower level of sales growth, higher gas prices, and the addition of 3 GW of CHP, which displaces standalone gas CCGT plants. About 2.6 GW less PV capacity is added, as PV is a lower load factor resource and is not as profitable with a flatter price profile. Finally, new demand response programs reduce 2032 peak load by more than 3.8 GW, providing about 3.8% of total system capacity.

Several other capacity differences between the reference cases are more predictable. An additional 3.4 GW of older steam oil and gas retires, with 4.9 GW remaining as of 2032. Consistent with the flatter load profile, the Phase II addition of 660 MW of CTs becomes a net 450 MW reduction in CT capacity by 2032 in Phase III.

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[64] Actual modeled capacity of existing demand response was slightly lower in this scenario, but the difference does not materially change model results. This table has been revised to reflect the finalized 2,547 MW of existing demand response capacity in ERCOT.

[65] The 5,119 MW of wind and 532 MW of solar by 2017 in this table, Table VII-3 and Table VII-5 are the plants with either the in-service date after 2012 or under construction as reported by Energy Velocity as of Apr 1st, 2014. As compared to ERCOT's queue, this understates wind builds in the Panhandle area. This would likely not affect our EE, DR, and CHP results, but may result in slightly overstated new CCGT additions.

[66] As explained in the prior footnote, the figures in this subsection compare the Phase III Reference Case to the Phase II Reference Case with Required Reserves.

Figure VII-2: Generation mix by fuel type for Phase III
Reference Case With New DR and New CHP
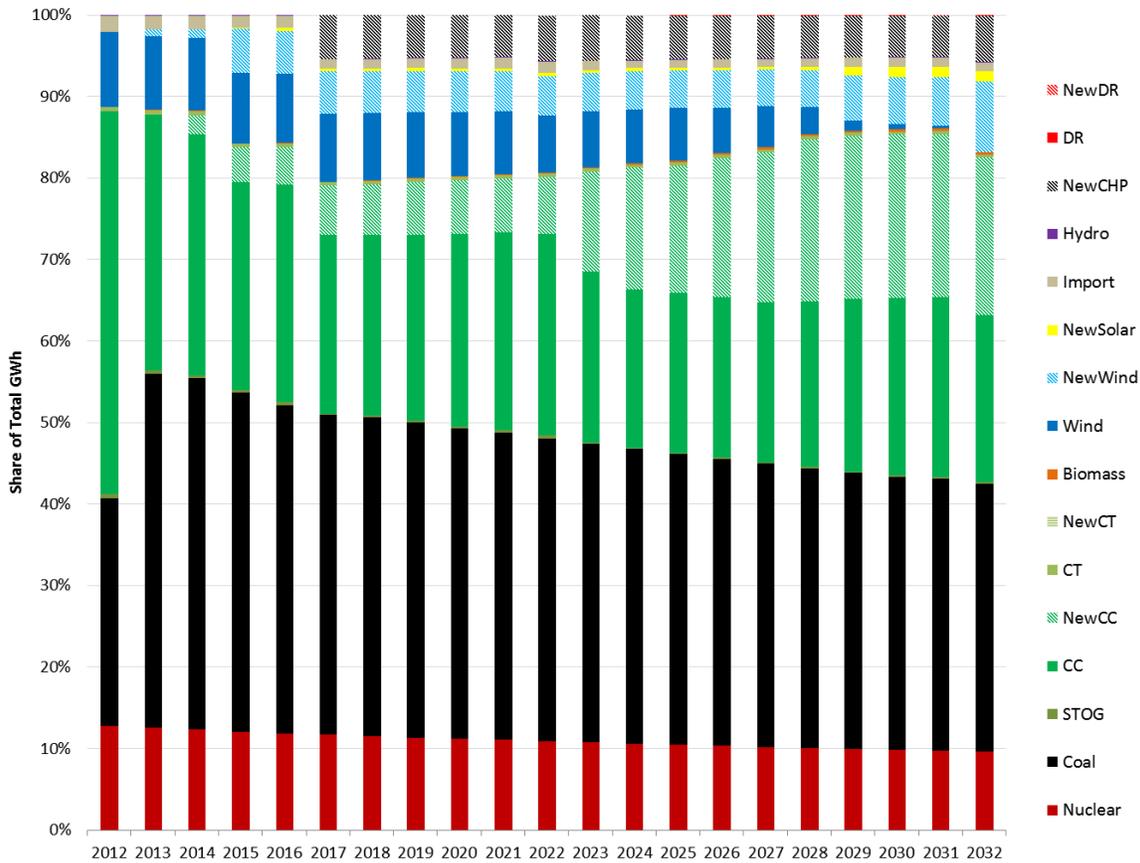
Apart from the very slight increase in coal's 2032 generation share, renewables increase their generation share significantly (10.7% in Phase III vs. 7.3% in Phase II) and CHP gains about a 6% share. In addition, because energy and ancillary services revenues and load growth cannot support the construction of the large number of new CCGTs in Phase II, the existing 31.6 GW fleet of CCGTs works much harder in Phase III, contributing roughly 20% of all energy in Phase III versus 10% in Phase II. These increases yield much less generation from new, efficient CCGTs, in conformance with the 10.6 GW less in CCGT capacity additions: 62,419 GWh in Phase III vs. 151,400 GWh in Phase II.

The net effects of these generation shifts are subtle. Slower sales growth, CHP, DR, and slightly higher gas prices together diminish new CCGT builds and thereby leave the overall fleet proportionately less energy-efficient (in the sense of average realized heat rate) than the larger, newer fleet in Phase II Reference. However, despite the slightly higher average heat rate in the gas CC fleet, overall carbon emissions are down slightly because less total energy is generated from any source and more is generated carbon-free renewables.

## B. Demand Response in the Reference Scenario

To an even greater extent than in Phase II, where our modeling of DR was highly simplified, DR plays its largest role in the Reference Scenario. More than 750 MW of DR are economical by 2017, displacing about one new CCGT plant; by 2022 3.3 GW is added and this rises to 3.8 GW by 2032. Table VII-2 below shows the deployment of each of the presumed DR programs within ERCOT in each of the converged years.

The top section of this table contains two rows, representing the programs that are not solely market-driven and are operated by ERCOT itself (i.e., the TDSP programs and ERCOT's three emergency interruption programs) or municipal utilities (i.e., the direct load control programs operated by CSP and Austin Energy). The first two columns indicate the maximum allowable number of hours of DR interruption under the program and the maximum hourly capacity over the period, which we hold constant. The third block of columns shows the maximum energy that each DR program could displace in each year. The fourth block of columns shows the amount of energy our simulation found that ERCOT would displace with these programs.[67] The fifth block of columns shows the average number of hours of dispatch per participant.

As shown, ERCOT almost never required emergency interruptions in our simulations; only the municipal programs were "dispatched" with any frequency. This finding should not be interpreted to mean that the ERCOT programs do not provide value to the system. The ERCOT programs are designed to be utilized in the case of extreme system emergencies. These emergencies are relatively rare but major events, thus requiring infrequent but highly valuable dispatch of the programs. Our modeling approach is not designed to capture the impact of these rare system emergencies. Rather, our objective is to develop a better understanding of grid dynamics under the normal system conditions that will typically be observed in ERCOT over our forecast horizon. So, while the existing ERCOT programs are not utilized in our reference case, they still are a significant source of reliability "option value" in our assessment.[68]

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[67] Since PSO models the lack of perfect foresight in operations, it limits DR usage to high price events, which happen more frequently in some years than in others, thus not necessarily employing DR to its maximum energy deployment limit.

[68] For further discussion of this "option value" of DR and the role of stochastic modeling to better capture the full benefits of DR, see Andy Satchwell and Ryan Hledik, "Analytical Frameworks to Incorporate Demand Response in Long Term Resource Planning," *Utilities Policy*, March 2014.

## Table VII-2: DR Deployment by Program for Phase III
## Reference Case With New DR and New CHP

| | Annual disptach limit per participant (hours) | Capacity (MW) | | | Energy Limit (MWh) | | | Energy deployment (MWh) | | | Average Deployment per Participant (Hours) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2017 | 2022 | 2032 | 2017 | 2022 | 2032 | 2017 | 2022 | 2032 | 2017 | 2022 | 2032 |
| **Existing programs** | | | | | | | | | | | | | |
| ERCOT reliability-based DR programs | Varies | 2,163 | 2,163 | 2,163 | 9,963 | 9,963 | 9,963 | 0 | 390 | 40 | 0 | 0 | 0 |
| Muni DLC programs | 40 | 376 | 376 | 376 | 15,040 | 15,040 | 15,040 | 6,499 | 8,795 | 14,967 | 17 | 23 | 40 |
| **New programs** | | | | | | | | | | | | | |
| Residential air-conditioning DLC | 75 | | 677 | 946 | | 50,775 | 70,950 | | 29,693 | 70,605 | | 44 | 75 |
| Small C&I air-conditioning DLC | 75 | 28 | 176 | 184 | 2,100 | 13,200 | 13,800 | 907 | 7,719 | 13,733 | 32 | 44 | 75 |
| Medium/large C&I interruptible | 75 | 282 | 1,357 | 1,485 | 21,150 | 101,775 | 111,375 | 9,139 | 59,517 | 110,834 | 32 | 44 | 75 |
| All customers CPP | 50 | 454 | 1,097 | 1,197 | 22,700 | 54,850 | 59,850 | 21,577 | 30,844 | 35,340 | 48 | 28 | 30 |

*Note: Average deployment hours for ERCOT reliability-based DR programs appear to be zero due to rounding.*

The second, lower block of programs in Table VII-2 are the new market-driven programs we add to the simulation. These are a residential and small commercial air conditioning load cycling program (first two rows of the lower block), a price-driven medium and large C&I interruptible tariff (third and fourth rows) and an opt-in critical peak pricing (CPP) program available to all customers.

The dynamic pricing option is a highly cost-effective and attractive DR opportunity. Since AMI has already been deployed across the state, the incremental cost of offering dynamic pricing is extremely small. Even with modest enrollment assumptions, we find that it could provide over 1 GW of peak demand reduction by the end of the forecast horizon. The medium C&I customer segment is also a relatively untapped but cost-effective DR opportunity. While many of the large C&I customers in Texas are already participating in ERCOT's existing programs, the medium C&I customers are the single largest source of new DR in our market simulations. Residential DLC is also an attractive untapped and cost-effective opportunity, with a slightly higher cost per kilowatt of demand reduction.

As in the upper block, there are five groups of columns: the maximum number of hours a participant in the program can be called for deployment, maximum hourly capacity, maximum annual MWh displaced, simulated annual MWh displaced, and average hours of dispatch per participant, respectively. The fourth group of columns shows the following results:

- In 2017, most of these programs are used at less than half their energy displacement potential; the exceptions are CPP, which is nearly fully deployed, and residential load control, which is not used at all;

- In 2022, essentially all the programs are used at something in the neighborhood of half their energy displacement potential; and

- In 2032, all the programs other than CPP are displacing at near their maximum potential (i.e., are being used nearly up to their limit).

These results clearly indicate the value of expanded DR programs in the ERCOT energy-only marketplace.

## C. COMBINED HEAT AND POWER

Our results for CHP are quite straightforward.  The lowest-cost supply of CHP is found in a moderate number of petrochemical facilities with the potential for electric plants larger than 100 MW.  These CHP plants are able to use combined-cycle technologies quite similar to those employed by modern power-only plants, achieving net heat rates for electric generation of 4,500 Btu/kWh, which is well below the 6,736 Btu/kWh of a standalone combined cycle of similar size and technology.  As explained in Chapter VI above, we estimate the potential for CHP in this size range to be 2,304 MW in 2017, growing to 2,595 MW and 2,966 MW in 2022 and 2032, respectively.

This tranche of CHP is economical in every one of our Phase III simulations and is modeled as if it is market-induced.  However, no CHP beyond this tranche is found economical in any of our cases.  The reason is clear from Table VI-2 -- the next cheapest CHP technology is reciprocating engines in the 5 MW size class, with net heat rates for electricity generation of about 4,950 Btu/kWh and levelized costs of about $80/MWh.  Since none of our prices attain this level in our scenarios, the market does not choose to build CHP beyond the large, economical tranche in petrochemical plants.

Of course, these results are a function of the technology assumptions in Chapter VI, including an absence of breakthroughs in microcogen and other CHP technologies.  CHP can also be driven by special needs for reliable or resilient power, as in microgrids, considerations not included in the present modeling system.  Accordingly, our results should be considered a lower bound for CHP potential, especially if supportive policies are adopted, resilience becomes a greater concern, or there are technical breakthroughs.

## D. REFERENCE CASE WITH DR, CHP, AND ENHANCED ENERGY EFFICIENCY PROGRAMS

Our second Phase III scenario adds a relatively modest energy efficiency program portfolio, described in Chapter V, to the ERCOT market.  These programs include an early-replacement and upgrade program for residential air conditioners via rebates, a commercial indoor lighting upgrade program and an industrial pumping efficiency program.  Together, these programs were sized to provide about 1,175 GWh of additional savings each year, reducing the average rate of sales growth by a modest 0.1%.  It is worth noting, however, that these particular measures also impacted peak load quite significantly, so they served as something of a dual function, reducing both peak (like a DR program) as well as energy use.

While modest, this expanded EE program has substantial impacts on the ERCOT market.  Table VII-3 and Figure VII-3 show capacity additions by type for the scenario with added EE programs (all other aspects of this scenario are identical to the Phase III Reference case above).  Compared

to the Phase III reference, the expanded EE scenario triggers the retirement of about 1.2 GW additional old steam oil and gas capacity by 2032 and displaces 1.4 GW of PV and 500 MW of DR. In technical terms, this peak-reducing EE portfolio removes inefficient resources from the supply stack and displaces additions of PV and DR, which depend strongly on peak period energy revenues. In contrast, wind capacity increases by approximately 1 GW, as its development does not depend on peak period energy revenues as much.

### Table VII-3: Existing and New Generating Resources for Phase III (MW)
### Reference Case With New DR, New CHP, and Enhanced EE

| | 2012 | 2017 | | | 2022 | | | 2032 | | | Growth, 2012-2032 | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| | Existing | Cumulative Retirements | Cumulative New Builds | Total | Cumulative Retirements | Cumulative New Builds | Total | Cumulative Retirements | Cumulative New Builds | Total | MW | % |
| Nuclear | 5,132 | 0 | 0 | 5,132 | 0 | 0 | 5,132 | 0 | 0 | 5,132 | 0 | 0% |
| Coal | 18,694 | 395 | 925 | 19,224 | 395 | 925 | 19,224 | 395 | 925 | 19,224 | 530 | 3% |
| Steam Oil/Gas | 12,616 | 6,662 | 0 | 5,954 | 6,662 | 0 | 5,954 | 8,972 | 0 | 3,644 | -8,972 | -71% |
| Combined-Cycle Gas | 31,644 | 743 | 4,013 | 34,914 | 743 | 4,579 | 35,479 | 1,082 | 11,327 | 41,888 | 10,245 | 32% |
| Combustion Turbine Gas | 4,833 | 210 | 0 | 4,623 | 616 | 0 | 4,217 | 616 | 0 | 4,217 | -616 | -13% |
| Internal Combustion Gas | 243 | 0 | 0 | 243 | 0 | 0 | 243 | 0 | 0 | 243 | 0 | 0% |
| Hydro | 542 | 0 | 0 | 542 | 0 | 0 | 542 | 0 | 0 | 542 | 0 | 0% |
| Biomass | 159 | 0 | 0 | 159 | 0 | 0 | 159 | 0 | 0 | 159 | 0 | 0% |
| Wind | 9,757 | 40 | 5,119 | 14,836 | 1,008 | 5,119 | 13,868 | 9,757 | 11,885 | 11,885 | 2,128 | 22% |
| Solar | 30 | 0 | 532 | 562 | 0 | 532 | 562 | 0 | 1,372 | 1,402 | 1,372 | 4572% |
| CHP | | 0 | 2,304 | 2,304 | 0 | 2,595 | 2,595 | 0 | 2,966 | 2,966 | 2,966 | N/A |
| Demand Response | 2,547 | 0 | 676 | 3,223 | 0 | 2,278 | 4,825 | 0 | 3,336 | 5,883 | 3,336 | 131% |
| TOTAL | 86,197 | 8,050 | 13,569 | 91,716 | 9,424 | 16,027 | 92,800 | 20,822 | 31,810 | 97,185 | 10,988 | 13% |

### Figure VII-3: Capacity Additions for Phase III
### Reference Case with New DR, New CHP, and Enhanced EE
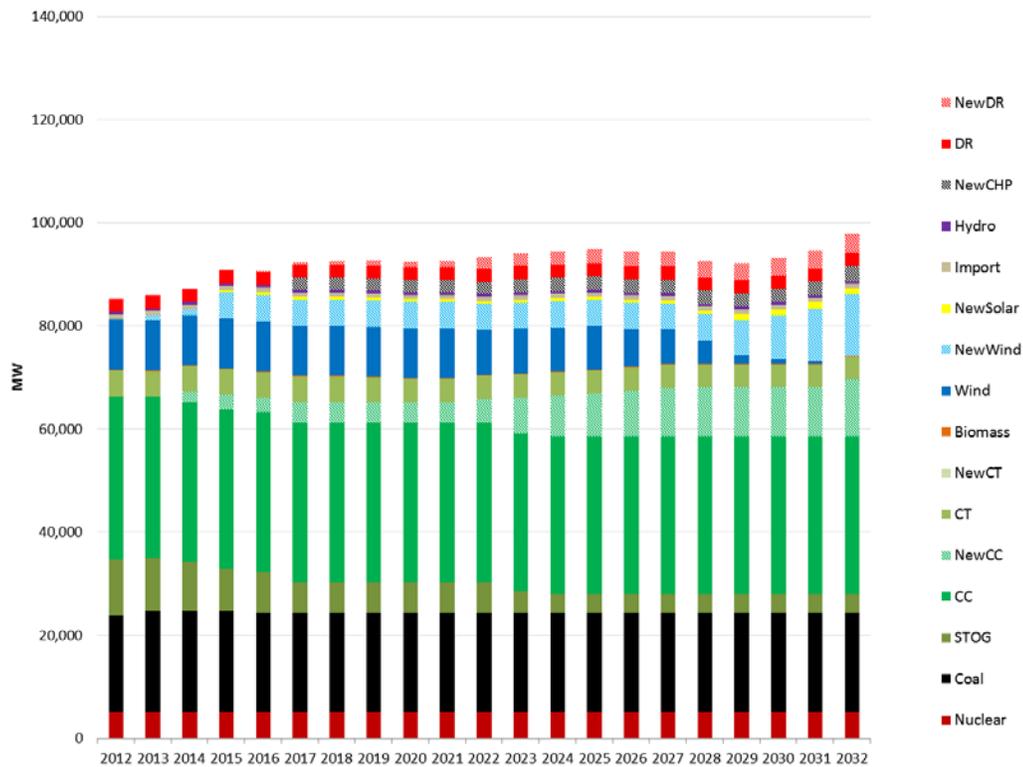
Figure VII-4 shows the generation mix share for the expanded EE scenario. In percentage terms EE's addition boosts coal generation by a slight 0.1% and renewables (wind) by 0.3%, lowering gas generation (excluding CHP) by about 0.6%. Demand response deployment is also very similar, deploying (as noted above) about 500 MW less, principally in the residential AC load control program.

Table VII-4 shows the capacity contributions of DR by program type in each converged year. Carbon emissions are also reduced by the EE portfolio.

**Figure VII-4: Generation Mix by Fuel Type for Phase III Reference Case With New DR, New CHP, and Enhanced EE**
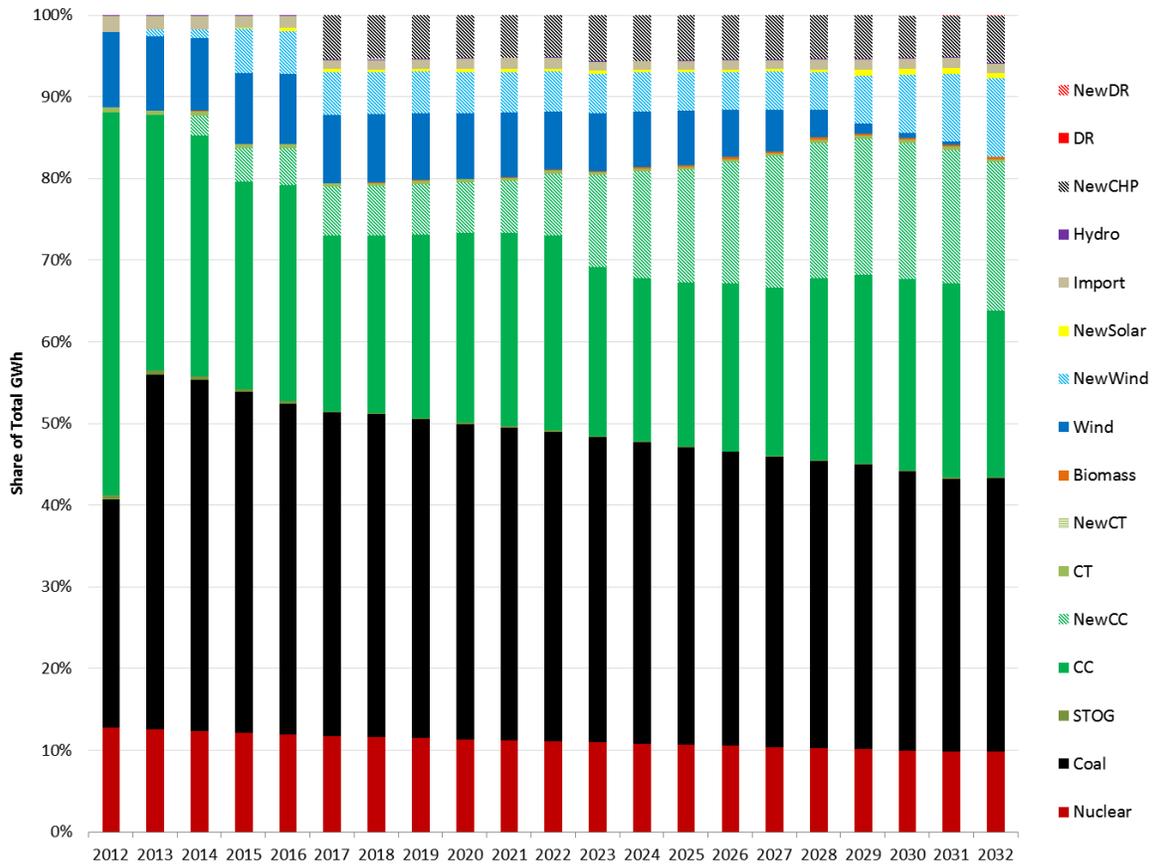
| Program | 2017 | 2022 | 2032 |
|---|---|---|---|
| Residential Air-Conditioning DLC | | 405 | 541 |
| Small C&I Air-Conditioning DLC | 28 | 176 | 167 |
| Medium and Large C&I Interruptible | 194 | 600 | 1,431 |
| All Customers CPP | 454 | 1,097 | 1,197 |
| **TOTAL** | **676** | **2,278** | **3,336** |

It is often argued that cost-effective demand-side resources should reduce average customer electricity bills. By comparing average customer energy bills in the Phase II Reference – which did not include our DR, EE, or CHP resources – with this Phase III scenario we can isolate the impact of these resources on customer bills. To do this, however, we must remove the cost-increasing effects of higher projected natural gas prices in Phase III versus Phase II.

Figure VII-5 examines total and average energy revenues paid by all ERCOT customers in the Phase II Reference Case (with required reserves) and the Phase III Reference scenario with enhanced EE. The results in this figure have been adjusted so that Phase III power prices are based on the same (lower) natural gas prices as in the Phase II reference. On this figure, the light blue bars are total Phase II ERCOT market revenues in each converged year and the dark blue bars are total revenues in the Phase III enhanced EE case. The figure shows that the EE/DR/CHP portfolio reduces annual total power costs by $1-$2 billion per year, or about $60 per ERCOT customer, at Phase II natural gas prices, net of customer capital and program costs not reflected in power prices. As explained in Chapter V, our separate calculations of program cost-effectiveness indicate that customers do save money overall from these programs.

**Figure VII-5: Generator Revenues in Phase II Reference Scenario and Phase III Reference With New DR, New CHP, and Enhanced EE**
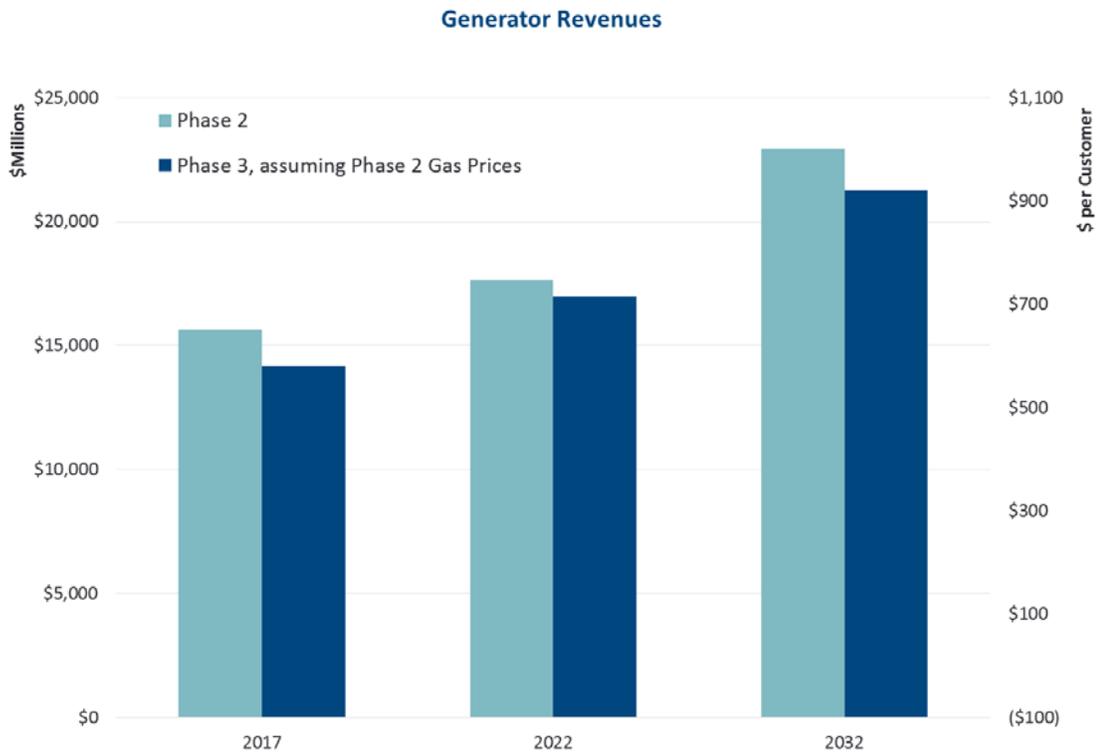


### E. MODERATE FEDERAL CARBON POLICY

This scenario begins with the Reference plus enhanced EE case and further assumes a carbon rule requiring 50% capture and sequestration of greenhouse gas emissions by coal plants by the year 2025. This carbon rule – identical to a counterpart scenario in Phase II – is the only change made to this scenario. However, unlike the remaining scenarios, this one was not converged between PSO and Xpand, so that the results understate the amount of ancillary services needed to maintain reliability. As these are now provided almost entirely by gas-fired plants, the new gas additions, or other future sources of ancillary services, are understated.

As expected, this rule triggers a 3.5 GW derating of most Texas coal plants in 2025 as these plants choose to retrofit 50% CCS technology rather than retire. The remaining impacts on capacity additions are shown in Figure VII-6 and Table VII-5. By 2032, an incremental 2.5 GW of wind and 1 GW of natural gas are built to replace the 3.5 GW of lost net coal capacity, along with 0.3 GW additional steam oil and gas plant whose retirement is deferred. In addition, about 250 MW more DR is deployed in this period and 800 MW *less* PV is added through 2032 as load profile

changes make PV less profitable.[69] On a pure present value energy cost basis, these results indicate that by 2025 the most economical replacement for coal-fired power is roughly a two-to-one combination of Texas wind and CCGT additions.

**Figure VII-6: Capacity Additions for Phase III Moderate Federal Carbon Policy**



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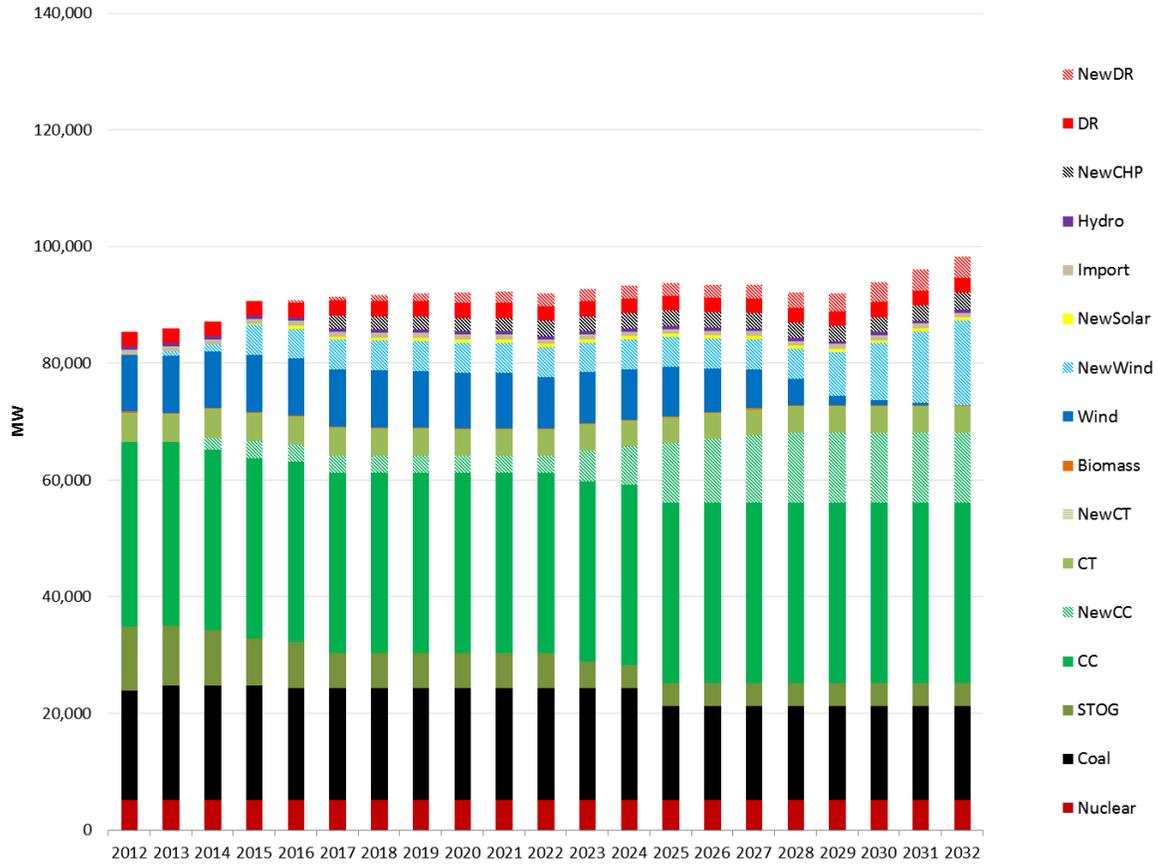
[69] DR deployment by program is nearly identical to Table VII-4, so we do not reproduce the detailed program use. The additional 250 MW in the 2032 time frame comes largely from residential AC load control

| | 2012 | 2017 | | | 2022 | | | 2032 | | | Growth, 2012-2032 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Existing | Cumulative Retirements | Cumulative New Builds | Total | Cumulative Retirements | Cumulative New Builds | Total | Cumulative Retirements | Cumulative New Builds | Total | MW | % |
| Nuclear | 5,132 | 0 | 0 | 5,132 | 0 | 0 | 5,132 | 0 | 0 | 5,132 | 0 | 0% |
| Coal | 18,694 | 395 | 925 | 19,224 | 395 | 925 | 19,224 | 3,471 | 925 | 16,148 | -2,546 | -14% |
| Steam Oil/Gas | 12,616 | 6,619 | 0 | 5,997 | 6,619 | 0 | 5,997 | 8,723 | 0 | 3,893 | -8,723 | -69% |
| Combined-Cycle Gas | 31,644 | 743 | 2,882 | 33,783 | 743 | 2,882 | 33,783 | 743 | 12,090 | 42,990 | 11,347 | 36% |
| Combustion Turbine Gas | 4,833 | 210 | 0 | 4,623 | 542 | 0 | 4,291 | 616 | 0 | 4,217 | -616 | -13% |
| Internal Combustion Gas | 243 | 0 | 0 | 243 | 0 | 0 | 243 | 0 | 0 | 243 | 0 | 0% |
| Hydro | 542 | 0 | 0 | 542 | 0 | 0 | 542 | 0 | 0 | 542 | 0 | 0% |
| Biomass | 159 | 0 | 0 | 159 | 0 | 0 | 159 | 0 | 0 | 159 | 0 | 0% |
| Wind | 9,757 | 40 | 5,119 | 14,836 | 1,008 | 5,119 | 13,868 | 9,757 | 14,453 | 14,454 | 4,697 | 48% |
| Solar | 30 | 0 | 532 | 562 | 0 | 532 | 562 | 0 | 532 | 562 | 532 | 1772% |
| CHP | | 0 | 2,304 | 2,304 | 0 | 2,595 | 2,595 | 0 | 2,966 | 2,966 | 2,966 | N/A |
| Demand Response | 2,547 | 0 | 685 | 3,232 | 0 | 2,145 | 4,692 | 0 | 3,580 | 6,127 | 3,580 | 141% |
| TOTAL | 86,197 | 8,008 | 12,447 | 90,636 | 9,308 | 14,198 | 91,086 | 23,310 | 34,546 | 97,432 | 11,236 | 13% |

While these cumulative new build totals through 2032 are important, it is also interesting to observe the different time patterns of construction between the Enhanced EE and Moderate Carbon scenarios. The difference in these scenarios provides a natural experiment in which 3.5 GW of coal is effectively removed overnight from the market in 2025.

Figure VII-7 and VII-8 compare the time sequence of new plant builds and retirements between the two scenarios. In this figure, the pattern of new builds is identical until 2025, when in the Moderate Carbon case (bottom timeline) 3.5 GW of coal capacity is removed from the market. As this timeline shows, the market reacts by immediately replacing these with CCGTs almost one-for-one, building 3.7 GW of new CCGT versus 0.5 GW in the Enhanced EE scenario in the same year (upper timeline).

Figure VII-7: Annual changes in Capacity for Phase III
CHP, DR, and Enhanced EE
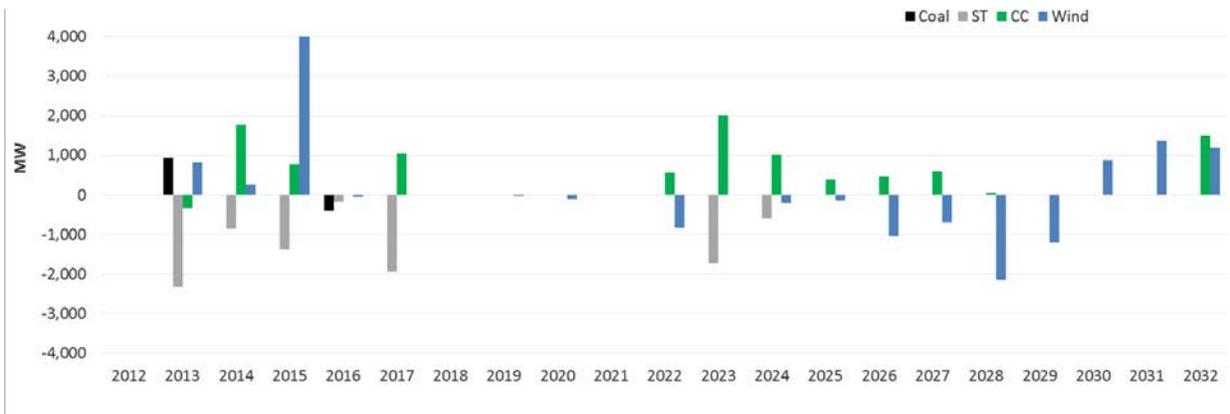


Figure VII-8: Annual changes in Capacity for Phase III
Moderate Federal Carbon Policy
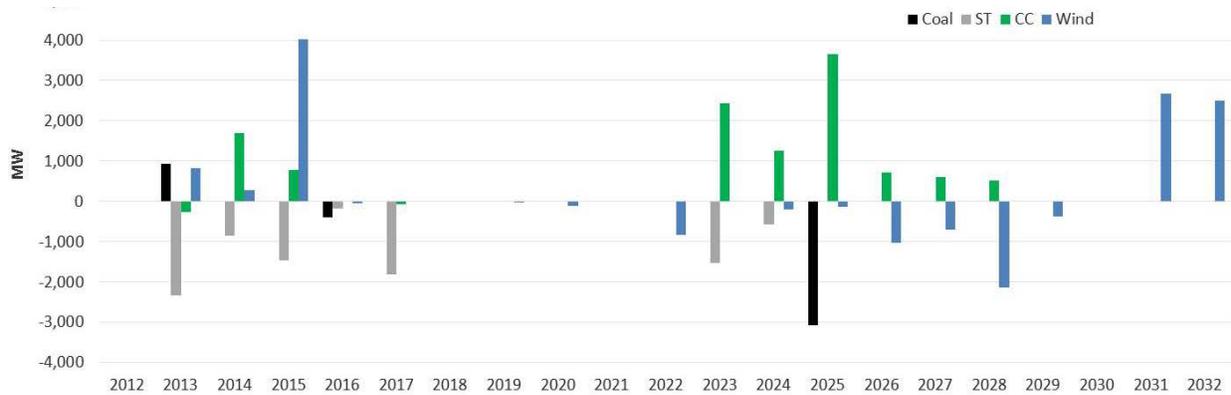
This added CCGT capacity in 2025 in the Moderate Carbon case leads to a sufficient supply of gas capacity so that the market does not need to add any more through 2032 while an incremental 2 GW of wind is added. In contrast, as wind and solar are built after 2025 in the Enhanced EE scenario, market and reliability needs together create a need for 2 GW additional CCGT capacity during this period. Thus, by 2032 there is only one additional GW of gas capacity added in the Moderate Carbon scenario, but gas additions occurred sooner, and in a much larger annual increment, than in the Enhanced EE scenario. As mentioned earlier, when ancillary services considerations are fully incorporated, additional integrative resources may be called for in the 2025-2032 time frame.

Energy generation results in the Moderate Carbon scenario mirror the capacity changes that occur relative to the Enhanced EE scenario after 2025 (see Figure VII-9). Coal's 2032 generation share declines from 35% to 28.6%, while both gas generation and renewables increase. Renewables' total 2032 generation share increases from 11% to 12.8%, while gas increases from 43.5% to 48.6%. Interestingly, in the Phase II Moderate carbon case, which had a significantly higher sales growth rate, renewables' share was only about 7%, while gas was 54%. These differences show the impacts of higher gas prices in Phase III boosting wind relative to natural gas in the final years of the period.

Figure VII-9: Generation Mix by Fuel Type for Phase III
Moderate Federal Carbon Policy
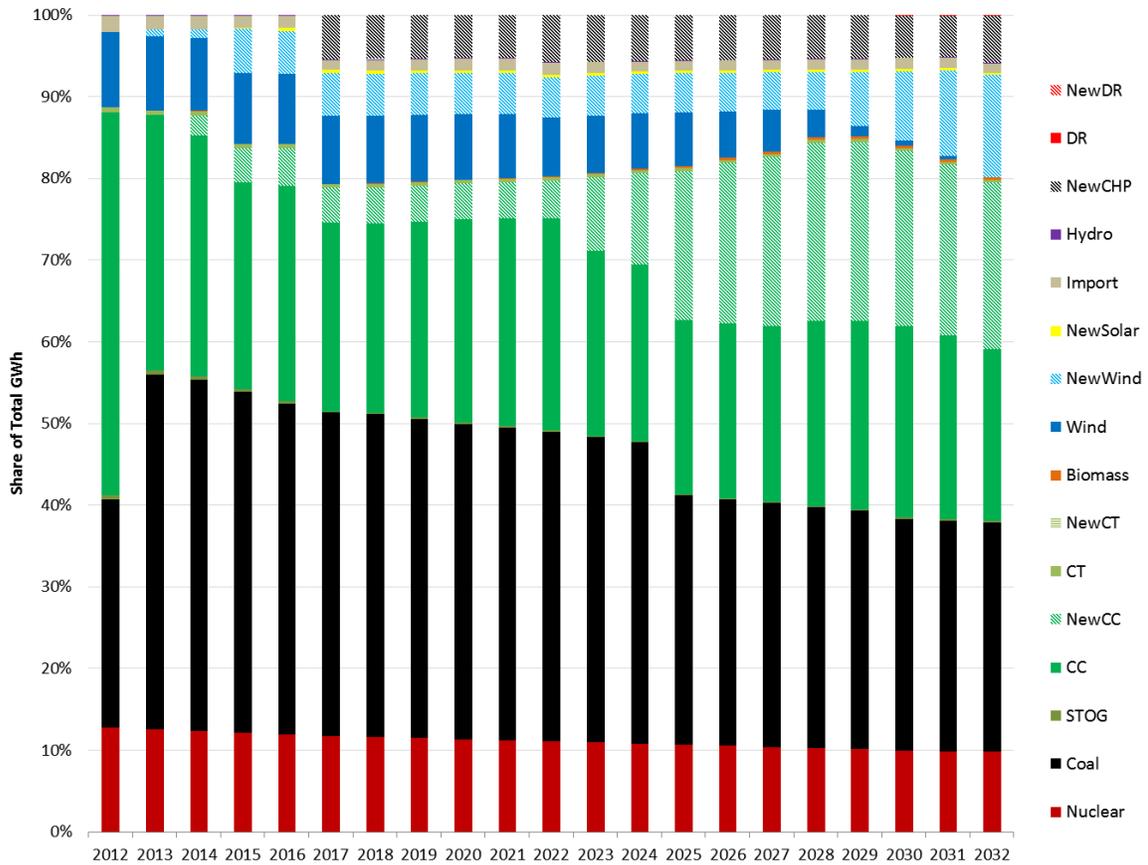
## F. STRONG FEDERAL CARBON POLICY

The Strong Federal Carbon Policy case includes a rule requiring all coal plants to capture and sequester 90% of their $CO_2$ by 2025, along with higher natural gas prices and lower renewables costs. The capacity shifts under this disruptive scenario are substantial, as shown in Figure VII-10 and Table VII-6. Equally dramatic shifts in the generation mix are shown in Figure VII-11.

# Figure VII-10: Capacity Additions for Phase III
## Strong Federal Carbon Policy
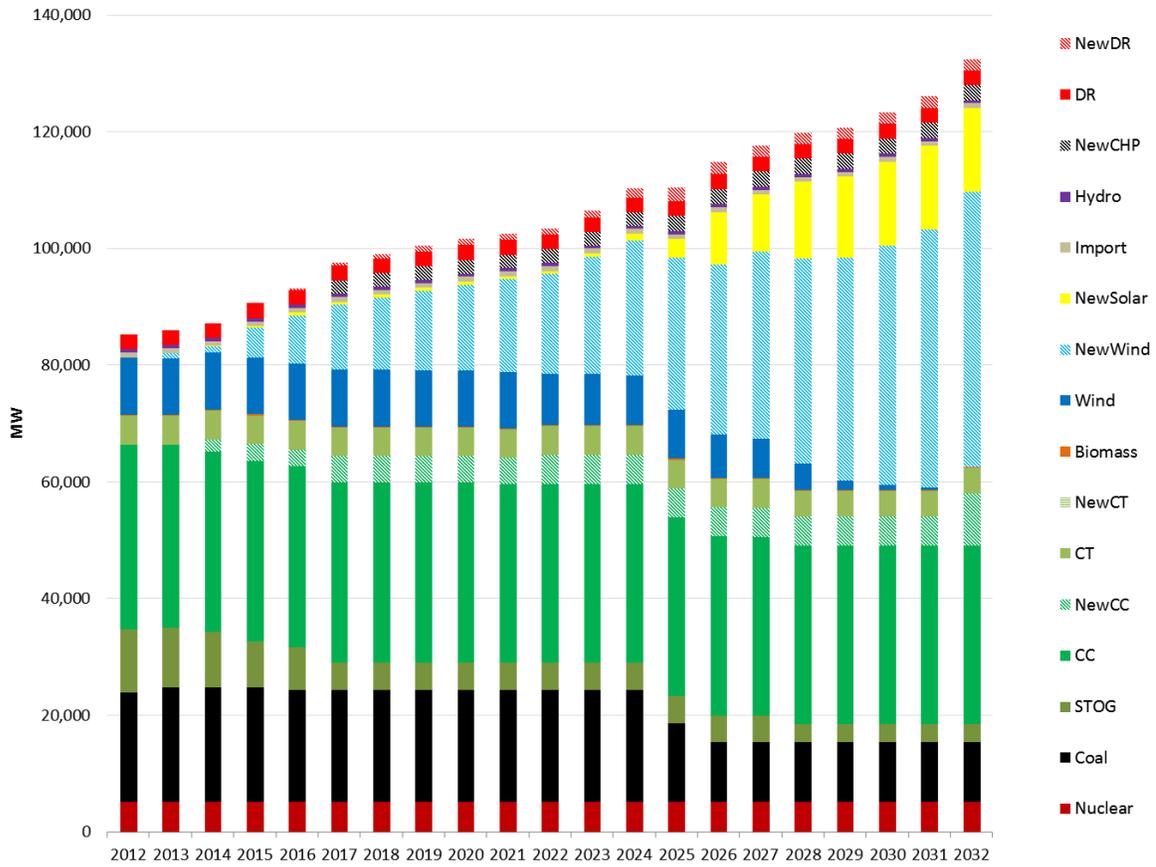


# Table VII-6: Existing and New Generating Resources for Phase III (MW)
## Strong Federal Carbon Policy

| | 2012 | 2017 | | | 2022 | | | 2032 | | | Growth, 2012-2032 | |
| | Existing | Cumulative Retirements | Cumulative New Builds | Total | Cumulative Retirements | Cumulative New Builds | Total | Cumulative Retirements | Cumulative New Builds | Total | MW | % |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Nuclear** | 5,132 | 0 | 0 | 5,132 | 0 | 0 | 5,132 | 0 | 0 | 5,132 | 0 | 0% |
| **Coal** | 18,694 | 395 | 925 | 19,224 | 395 | 925 | 19,224 | 9,572 | 925 | 10,047 | -8,647 | -46% |
| **Steam Oil/Gas** | 12,616 | 7,955 | 0 | 4,661 | 7,955 | 0 | 4,661 | 9,510 | 0 | 3,106 | -9,510 | -75% |
| **Combined-Cycle Gas** | 31,644 | 743 | 4,465 | 35,365 | 1,024 | 4,992 | 35,612 | 1,082 | 10,047 | 40,609 | 8,965 | 28% |
| **Combustion Turbine Gas** | 4,833 | 156 | 0 | 4,677 | 156 | 0 | 4,677 | 640 | 0 | 4,193 | -640 | -13% |
| **Internal Combustion Gas** | 243 | 0 | 0 | 243 | 0 | 0 | 243 | 0 | 0 | 243 | 0 | 0% |
| **Hydro** | 542 | 0 | 0 | 542 | 0 | 0 | 542 | 0 | 0 | 542 | 0 | 0% |
| **Biomass** | 159 | 0 | 0 | 159 | 0 | 0 | 159 | 0 | 0 | 159 | 0 | 0% |
| **Wind** | 9,757 | 40 | 11,119 | 20,836 | 1,008 | 17,119 | 25,868 | 9,757 | 47,119 | 47,119 | 37,362 | 383% |
| **Solar** | 30 | 0 | 532 | 562 | 0 | 532 | 562 | 0 | 14,321 | 14,351 | 14,321 | 47736% |
| **CHP** | | 0 | 2,304 | 2,304 | 0 | 2,595 | 2,595 | 0 | 2,966 | 2,966 | 2,966 | N/A |
| **Demand Response** | 2,539 | 0 | 454 | 2,993 | 0 | 1,367 | 3,906 | 0 | 2,310 | 4,849 | 2,310 | 91% |
| **TOTAL** | 86,189 | 9,289 | 19,799 | 96,698 | 10,538 | 27,530 | 103,180 | 30,561 | 77,688 | 133,316 | 47,127 | 55% |

## Figure VII-11: Generation Mix by Fuel Type for Phase III Strong Federal Carbon Policy
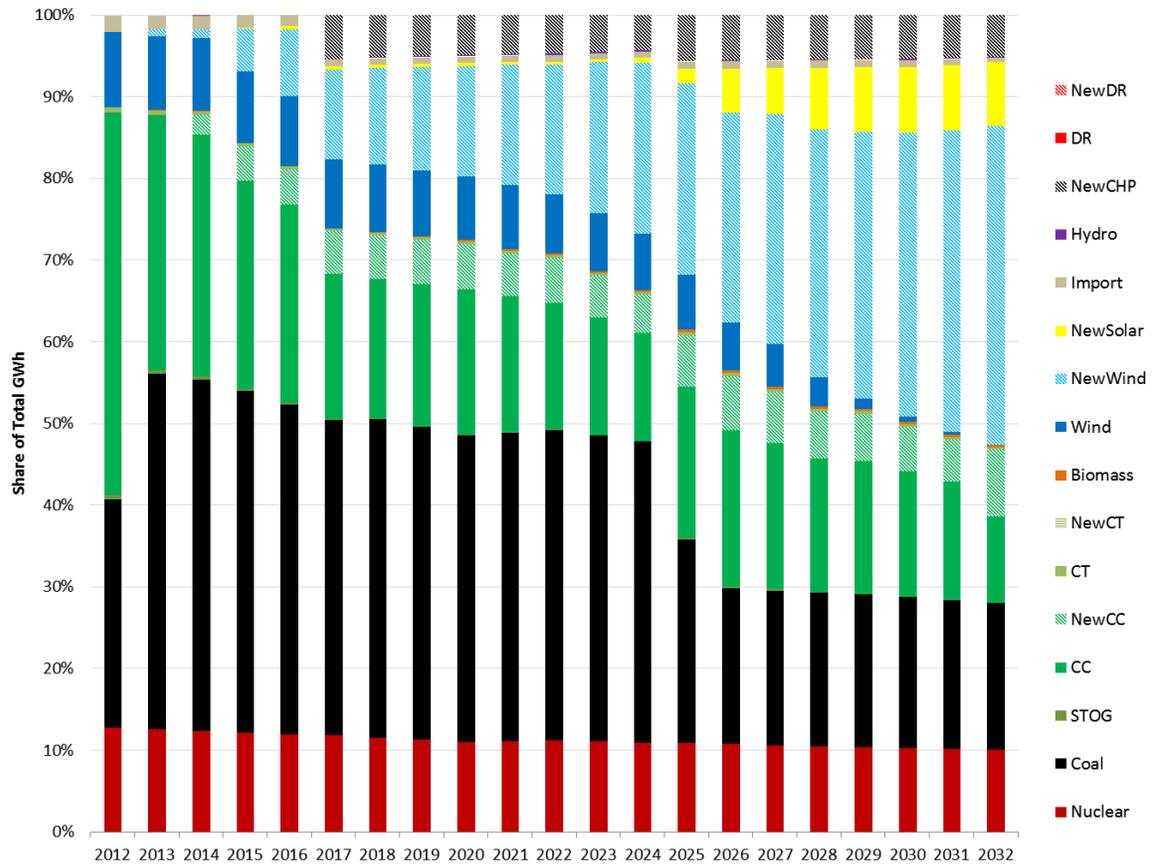


The strong federal carbon rule prompts about half the ERCOT coal fleet to retire in 2025, or about 9.6 GW of the 18.7 GW fleet. While this is a substantial change in capacity, it is 6.5 GW less than the Phase II Strong Carbon case because natural gas prices are higher in this scenario. These results highlight the sensitivity of coal retirement decisions to gas prices: roughly one additional (2012) dollar per MMBtu is sufficient to reduce coal retirements by more than one-third. However, these higher gas prices are not sufficient to rescue the economics of older steam oil and gas units; over three-fourths of the 12.6 GW fleet retires by 2032.

Consistent with other scenarios, these capacity losses are replaced by a combination of EE, DR, gas and renewable resources. As seen in the Enhanced EE scenario, EE and DR alone remove the need for about half the new capacity additions of any type through 2032. As in the other Phase III scenarios, the EE, DR, CHP, and slower overall growth cause the remaining supply side capacity additions to tilt a little more towards wind and away from new gas and solar. Ten (10) GW of new CCGT and 3 GW of CHP are added – about half the comparable Phase II levels – along with a total of 14 GW of PV, 2 GW more than in Phase II. The largest effect by far occurs

in wind builds, which sees about 47 GW of wind[70].  Thanks to these shifts, renewables achieve a 2032 generation share of 46.3%, close to double that of gas (27.3%) and three times the level of coal (15.9%).

Interestingly, the Strong Federal Carbon case reverses the trend toward greater deployment of DR resources.  As shown in Table VII-7, DR capacity in every converged year declines about one third from all of the other Phase III scenarios meanwhile solar PV capacity has increased significantly from about 1.4 GW to over 14 GW in 2032 due to the high natural gas prices and faster declining cost of solar PV.

### Table VII-7: Peak Load Displacement by DR (MW)
### Strong Federal Carbon Policy

| Program | 2017 | 2022 | 2032 |
|---|---|---|---|
| Residential Air-Conditioning DLC | | | |
| Small C&I Air-Conditioning DLC | | | |
| Medium and Large C&I Interruptible | | 270 | 1,113 |
| All Customers CPP | 454 | 1,097 | 1,197 |
| **TOTAL** | **454** | **1,367** | **2,310** |

## G. CONCLUDING OBSERVATIONS

As we have found in all our work for TCEC, the relationship between natural gas and renewable generation is multifaceted, with substantial room for both to grow in nearly all futures.  In Phase II, gas prices, renewable policies, and renewable cost reductions stood out as critical drivers of the mix between these two types of generation.  In Phase III these findings continue to hold, but they are shaped by DR and EE which reduce overall sales and peak demand.  In Phase III, capacity growth is a little more evenly divided between gas and renewables relative to Phase II.

A particularly good example of this is illustrated by the capacity additions in the Moderate Carbon scenario.  As noted above, the abrupt loss of 3.5 GW of coal-fired capacity causes the market to immediately supply a similar amount of CCGT capacity and later build out higher levels of renewables, ultimately ending with a two-to-one ratio of renewable nameplate capacity additions to CCGT additions.  Since wind capacity produces about half the energy per rated MW, the incremental energy contributions are more closely aligned.

Our results also show that expanded DR and energy efficiency options help reduce total energy costs and can be successful in ERCOT's market-driven environment.  By 2017 we identify between 450 and 760 MW of economic, achievable DR in ERCOT across our scenarios, a 20% to 30% increase over the existing ERCOT portfolio.  By the end of our forecast horizon, the

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[70] This includes the planned builds as discussed in footnote 65.

economic new DR grows to between 2.3 and 3.8 GW, a 90% to 150% increase over the current portfolio (it varies by scenario). This includes dynamic pricing, which is cost-effective in all scenarios and capable of providing more than 1 GW of peak reduction by 2032. In our reference case, the size of the total DR portfolio (existing and new) in 2032 is 6,350 MW, 7.8% of the projected system peak (the relative size of the DR portfolio exceeds the national average of existing DR across ISO/RTOs of around 6%). Of this total, new DR capacity is between 2.3 GW and 3.3 GW, depending on the carbon policy scenario. Combined with 3 GW of peak reduction in the expanded EE portfolio, this represents a 40% to 50% reduction in projected peak demand growth over the forecast horizon.

These results also show several subtle tradeoffs between DR and other resources. For example, slower load growth encourages older base load resources to stick around, which is economical, but slows the turnover of the fleet. This has a two-edged effect on fuel efficiency and emissions, slowing the growth of new CCGTs but generally increasing the growth of wind power but not solar. Thus, DR in the ERCOT system is more complementary to wind than to either solar or gas. Of course, the most important feature of DR is that it saves customers' money by deferring plant construction, while still reducing emissions overall.

Conversely, strong carbon policies reduce the need for DR by necessitating fleet turnover. However, even here we see that slower growth, DR, and EE as well as higher gas prices induce about twice as much wind development as CCGT additions when coal plant capacity is removed.

If one assumes that the U.S. will adopt a strong carbon policy in the long term but not in the near term, the logical evolution of these resources might be to emphasize DR and energy efficiency now. Since DR does not have large long-term capital servicing requirements, few costs would be "stranded" when a stronger climate policy triggered a larger fleet transition than current policies allow.

The combined effects of lower load forecasts, DR, EE and CHP have slightly reduced average customer bills and greenhouse gas emissions. The combined effects of higher gas prices, lower load growth, enhanced DR and CHP installations lower $CO_2$ emissions about 4% by 2032 versus the Phase II Reference Case, or 143 million metric tons. This is the equivalent of closing one 600 MW coal plant for 30 years. New EE programs further reduce $CO_2$ by 10 MMT, the equivalent of one year's emissions from an 800 MW coal plant. Table VII-8 shows the major air emissions under all Phase III scenarios.

### Table VII-8: Phase III Air Emissions

| Scenarios | 2032 Renewable Generation[1] | | 2032 Gas Generation | | CO2 Emissions | | 2032 SO2 Emissions | | 2032 NOX Emissions | |
|---|---|---|---|---|---|---|---|---|---|---|
| | MWh | % | MWh | % | Cumulative MMT | % Change vs. 2012 | Metric Tons | % Change vs. 2012 | Metric Tons | % Change vs. 2013 |
| Phase 2 Reference | 31,192,285 | 7.3% | 203,461,670 | 47.8% | 3,987.34 | 18.4% | 328,628 | 31% | 100,179 | 19.8% |
| Phase 3 Reference with CHP and DR | 45,880,515 | 10.7% | 189,593,590 | 44.1% | 3,844.99 | 14.7% | 333,691 | 33% | 101,411 | 21.3% |
| Phase 3 Reference with CHP, DR, and EE | 46,293,041 | 11.0% | 183,741,676 | 43.5% | 3,803.18 | 12.8% | 328,977 | 31% | 98,871 | 18.2% |
| Phase 3 Moderate Federal Carbon Rule | 55,754,977 | 13.2% | 203,618,418 | 48.4% | 3,308.68 | -22.6% | 316,224 | 26% | 98,120 | 17.4% |
| Phase 3 Strong Federal Carbon Rule | 196,101,335 | 46.3% | 115,669,521 | 27.3% | 2,471.46 | -76.2% | 219,555 | -13% | 67,940 | -18.7% |

[1] Includes hydroelectric and biomass generation

Average wholesale electricity market prices have risen across the board in our Phase III scenarios due to higher natural gas prices, partially offset by the price-reducing effects of DR, CHP, and EE. The net effect remains slightly higher prices for the Phase III scenarios versus their phase II counterparts. These results are shown in Figure VII-12, which shows all Phase II average price results (lighter bars) alongside Phase III scenarios (darker bars). In inflation-adjusted terms, prices in the Reference scenarios remain within the band observed between 2010 and 2012, from a low of about $42/MWh to a high of about $67/MWh under the strong carbon rule. Importantly, the inclusion of EE, DR, and CHP in the Phase III scenario reduces the higher-priced carbon rule scenarios, as what would otherwise have been. In Phase II, 2032 prices in the carbon rule cases topped out at almost $70/MWh, $3/MWh more than the same scenario in Phase III.

## Figure VII-12: Phase II vs. Phase III Average Prices
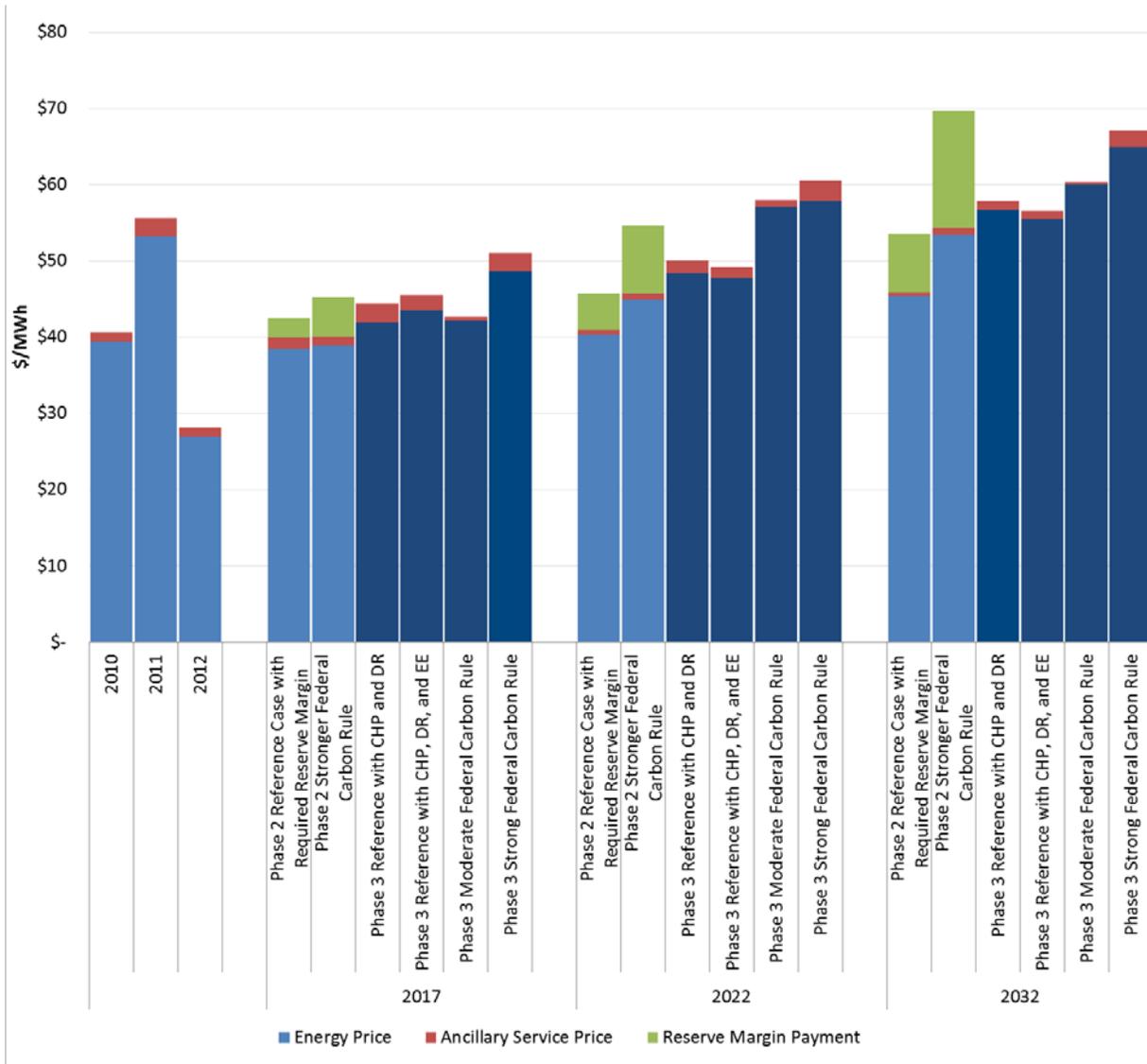


We began our ERCOT simulations for TCEC to examine tradeoffs and complementarities between gas-fired and renewable generation sources. With the results of this Phase, we integrate energy efficiency, combined heat and power, and demand response into ERCOT's future. This larger set of options provides a richer set of tradeoffs and complements. Demand response and energy efficiency lower the need for new supply-side resources of any type in a cost-effective manner. Until carbon rules are in effect or other policies change, gas CCGT additions dominate supply-side additions until the late 2020s, when unsubsidized renewables begin to compete on price alone. Following this period – and especially following carbon rules - renewable capacity additions become the majority, but substantial gas investment continues to be made to integrate renewables into the system.

As with any modeling and market simulation, the specific results we have calculated are subject to many assumptions. Moreover, the range of results across our scenarios show that different price and policy futures will have an overwhelming influence on the future of ERCOT's grid. Amidst this huge range of specific outcomes, the sum total of our results indicate that both gas and renewables are likely to be developed in substantial amounts together in the Texas markets, with gas prices, carbon and renewables policies, and renewables price reductions servings as the most important drivers. In addition, our results show that expanded energy efficiency and demand response programs are economical for Texas energy customers across nearly every realistic future for the ERCOT market.

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