Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs

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All of the views expressed in this report are those of the authors and do not necessarily reflect the views or have the endorsement of those individuals above who shared their thoughts with the authors.

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- Conducting in-depth technical and policy assessments
- Advising policymakers and program managers
- Working collaboratively with businesses, public interest groups, and other organizations
- Organizing conferences and workshops
- Publishing books, conference proceedings, and reports
- Educating consumers and businesses

Projects are carried out by staff and selected energy efficiency experts from universities, national laboratories, and the private sector. Collaboration is key to ACEEE's success. We collaborate on projects and initiatives with dozens of organizations including federal and state agencies, utilities, research institutions, businesses, and public interest groups.

Support for our work comes from a broad range of foundations, governmental organizations, research institutes, utilities, and corporations.

EXECUTIVE SUMMARY

In the immediate and long-term future, energy efficiency, demand response, and onsite renewable energy resources can meet the growing demand for electricity in Texas. Efficiency and renewable energy resources, combined with a significantly expanded demand response, can meet 107% of the projected growth in summer peak demand by 2013, heading off the reserve margin crisis that is forecast for the state and actually reducing the overall summer peak demand in key years. These goals can be accomplished at a lower cost than by constructing new conventional generation resources, thus enhancing the energy security and sustaining the state's economic growth.

The Energy Challenge for Texas

The state of Texas is rapidly growing, with the state's population growing at a rate of 1.8% per year and the economy expanding at an annual rate of 3.8% from 2000 to 2006. It is projected that population growth will continue at a rate of 1.7% per year through 2023 (the horizon for this study), with the state's economy projected to grow at 3.2% per year.

The most pressing short-term policy concern in Texas is the rapid growth in peak demand. The Electric Reliability Council of Texas (ERCOT) reports that peak demand on the ERCOT system increased by about 2.5% per year between 1990 and 2006. The current forecast is for peak demand to increase by 2.3% annually from 2007 through 2012. ERCOT has raised the prospect that the state might be without sufficient generation capacity to meet peak demands as soon as 2009, creating images of a power crisis similar to that experienced in 2000 and 2001 in California.

The state's rapidly growing peak electric demand and electricity consumption have led ERCOT and utilities to suggest that Texas should take actions to change the mix of electric generating resources and lean heavily on building new coal-fired power plants. We suggest that demand-side and renewable resources, beyond conventional supply resources, should be considered as the state develops its near- and long-term energy plans. This report characterizes the potential for these key "alternative" resources and recommends policies to bring them on-line at the needed rate.

Energy Efficiency, Demand Response, and Onsite Renewable Resources

Texas has already taken progressive steps in the area of clean energy through its renewable energy portfolio (RPS) and its energy efficiency improvement programs (EEIP), which direct transmission and distribution utilities to serve 10% of load growth through energy efficiency. The utilities have easily met the efficiency target, and Texas already gets more than 4% of its electricity from wind, so the state is on track to exceed the levels in the RPS. However, there is much more that can be achieved from energy efficiency and renewable energy resources. In particular, the level of savings that utilities can achieve through the EEIP can be greatly and cost-effectively increased. In addition, the EEIP does not apply to cooperative and municipal utilities in the state. While some of these utilities are already active in this area, all should contribute to meeting the state's needs. In addition to the EEIP, there are several other policies that could provide more energy efficiency resources.

The potential for onsite renewable energy generation (including solar photovoltaic generation systems) is very large in Texas. This report estimates the size of the energy efficiency and onsite renewable energy resources in Texas, and suggests a suite of policy options that the state can consider to realize their achievable potential.

In addition, a significant opportunity also exists to expand the state's "demand response" resources to reduce system peaks, as has been recommended by ERCOT. If initiated soon and pursued aggressively, the combined deployment of demand response and the other clean energy resources described above can address the state's reserve margin concerns while ensuring that the state has adequate, affordable electricity to sustain its economic growth. This report explores the opportunities in Texas for additional energy efficiency, demand response, and onsite renewable energy, and outlines the policies and programs necessary to harness these resources to meet the state's future energy needs.

Policy Recommendations

We have assembled a portfolio of nine policies that our analysis suggests are both effective and potentially politically viable in Texas:

1. Expanded Utility-Sector Energy Efficiency Improvement Program
2. New State-Level Appliance and Equipment Standards
3. More Stringent Building Energy Codes
4. Advanced Energy-Efficient Building Program
5. Energy-Efficient State and Municipal Buildings Program
6. Short-Term Public Education and Rate Incentives
7. Increased Demand Response Programs
8. Combined Heat and Power (CHP) Capacity Target
9. Onsite Renewable Energy Incentives

By implementing these clean energy resource policies, Texas can meet its summer peak demand needs without any additional coal-fired power plants or other conventional generation resources. Expanded demand response programs, combined with the demand reduction from energy efficiency investments, combined heat and power, and onsite renewables, would reduce the 2013 projected summer peak (MW) by 12% and the 2023 peak by 33% (see Figure ES-1).

In addition to their peak demand capacities, these combined policies would meet 8% of Texas's electricity consumption in 2013 and 22% in 2023 (see Figure ES-2). The most significant energy efficiency recommendations are for improved Combined Heat and Power policies and a Utility-Sector Energy Efficiency Program. In our recommendations, an Energy Efficiency Improvement Program (a utility savings target similar to the Renewable Portfolio Standard concept) and improved policies to expand CHP would each produce about 30% of the total savings. Creating incentives for building owners to invest in solar and other onsite renewable energy would produce 22% of the total savings. Improved building codes, appliance standards, and public building efficiency initiatives would meet 13% of the 2023 electricity usage, and are important due to the rapid growth of electricity usage in buildings.

Figure ES-1. Fraction of Summer Peak Demand that Can Be Met with Demand Response, Efficiency, and Renewable Resources

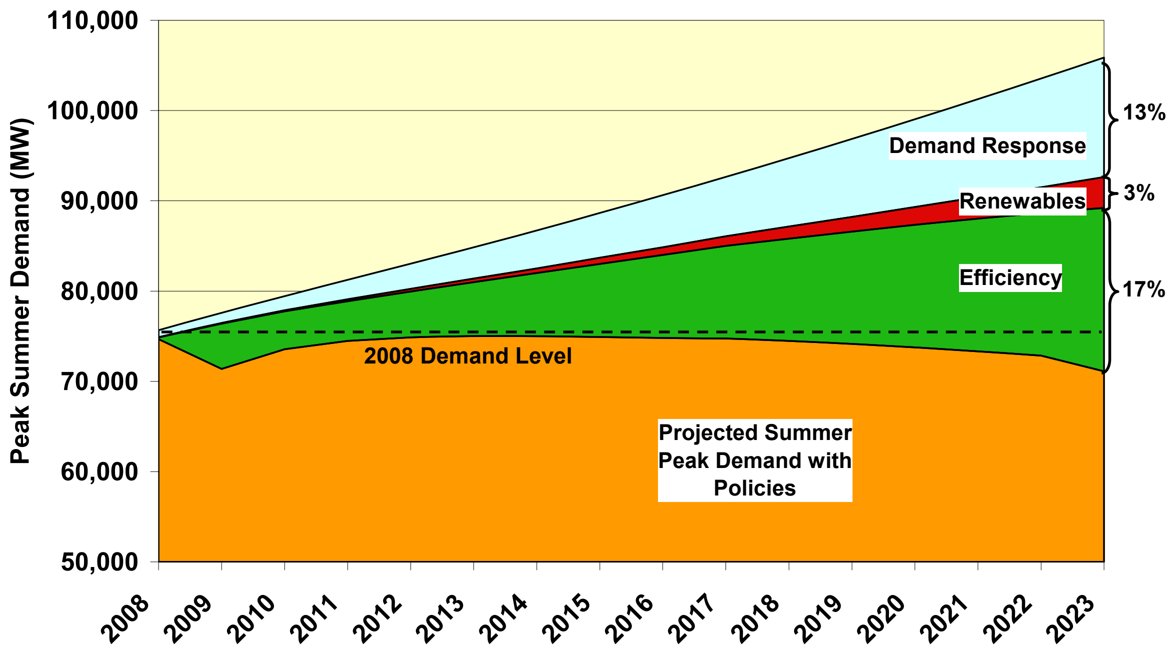
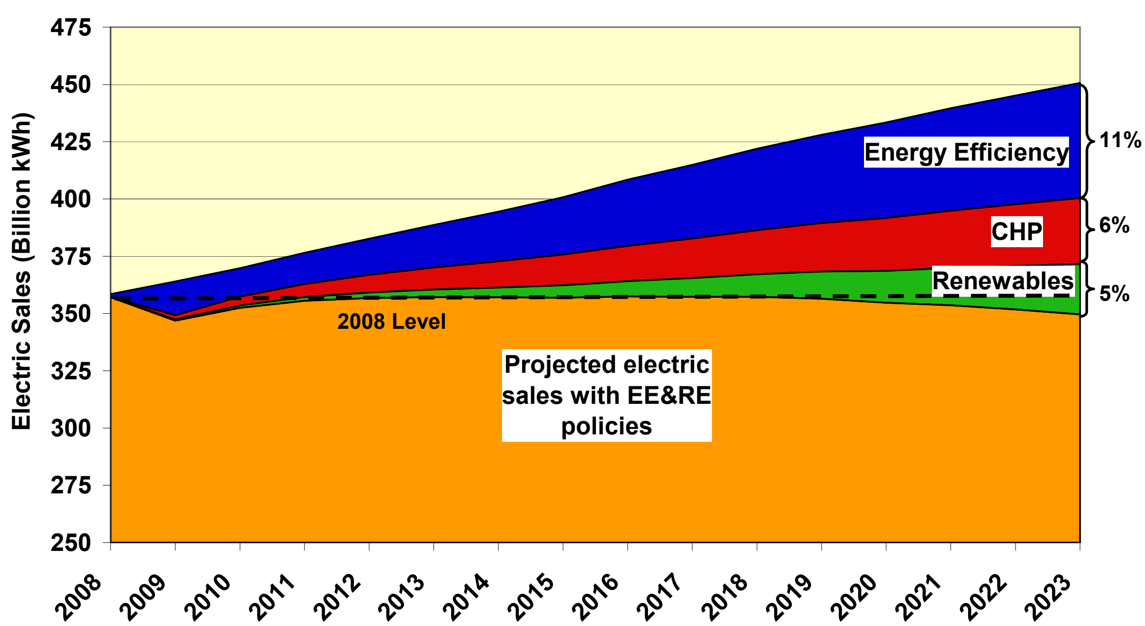


Figure ES-2. Share of Future Electricity Consumption that Can Be Met with Efficiency and Renewables Resources



These policies have proven effective and economic in other states when compared with conventional resource options, and would establish a foundation upon which the state could build a sustainable energy future, while bolstering the state's economic health. There are certainly other policy options available, but those described in this report appear to be the most appropriate for Texas given its history and opportunities.

The clean energy policies analyzed in this report will spur investments in energy efficiency and renewable energy, resulting in utility bill savings of $73 billion or more over the next 15 years for the consumers who make these investments, while helping to moderate electricity prices for all consumers. The suite of policies we recommend has a levelized energy cost of 4.5¢ per kilowatt-hour, including capital investment in clean energy technology and administrative costs. This compares favorably with a current average retail electric price of 9.1¢ per kilowatt-hour.

The total cost of implementing all of these programs (incentives plus program and administrative costs) averages about $800 million per year. These public investments leverage much larger total investment by consumers (fourfold higher). While these public investments will be borne in most cases by Texas's electric consumers in the form of a public benefits charge, their net impact will reduce future electricity costs for all consumers.

Importance of the Clean Energy Path for Texas's Energy Future

Policy action to adopt the energy efficiency and renewable energy policies described in this report would set Texas on a course to avoid near- and long-term electricity supply crises, while helping to stabilize energy prices. Efficiency and onsite renewables, when combined with expanded demand response programs, can also resolve concerns about meeting peak summer demands in the next few years, thus answering the question of where the state will get the electricity it needs to sustain its growing economy. While no single policy solution will address the state's longer-term energy challenges, the portfolio of policies proposed in this report will go a long way toward meeting Texas's future energy needs while ensuring its continued economic health.

INTRODUCTION

Texas is growing: population grew at 1.8% per year and the economy expanded 3.8% annually from 2000 to 2006. This growth has been accompanied by rising electricity demand of over 2% per year. Population is expected to grow at a rate of 1.7% per year through 2023 (the horizon for this study), with the state's economy projected to grow at 3.2% per year (Economy.com 2007). This rapid growth has resulted in rapid increases in the state's electricity demands.

The key question is: how fast does electricity supply need to increase to serve Texas growth? The Electric Reliability Council of Texas, which coordinates grid operations for 85% of the state, projects consumption to grow at an annual 1.7% rate over the next 15 years.[5] This report assesses the potential for Texas to meet its future energy service needs through energy efficiency, demand response, and renewable energy.

Texas's electricity outlook has been made more uncertain by the announced agreement by TXU to cancel plans for construction of eight new coal power plants, which has led the *Wall Street Journal* to suggest that "(t)he plant cancellations, if they happen, could have an interesting effect. Proposals by other plant builders, which went dormant after TXU made its big splash, could be revived. If more plants aren't built, an equally troubling scenario may unfold: Power prices could spiral out of control in Texas because there aren't enough suppliers to meet the need and the state is so poorly connected to other states, by high voltage wires, that there's no ability to import power." (Kingsbury 2007) Our report suggests that efficiency and conservation,[6] demand response, and onsite renewable energy can meet this growing need for energy services.

More problematic than the rapid increase in electricity consumption has been the even more rapid growth in peak demand. ERCOT reported that peak demand on the ERCOT system increased by about 2.5% per year between 1990 and 2006. The current forecast is for peak demand to increase by 2.3% annually from 2007–2012 (ERCOT 2006a). This level of growth is threatening Texas's ability to maintain grid reliability at reasonable costs in the coming years, which will affect the costs of electricity and the state's healthy business and investment climate. The mid-2006 report from ERCOT raised the prospect that much of the state could lack sufficient generation capacity to meet peak demands as soon as 2008, creating images of a power crisis similar to that experienced in late 2000 and early 2001 in California (ERCOT 2006a). In February 2007, ERCOT suggested that the "reserve margin"[7]

[5] This rate is based on Electric Reliability Council of Texas (2006 and adjusted to add 15% of Texas load not in ERCOT). Eighty percent of the electricity load and 75 percent of the state's electricity customers fall within ERCOT, a self-contained power generation and consumption region spanning 200,000 square miles.

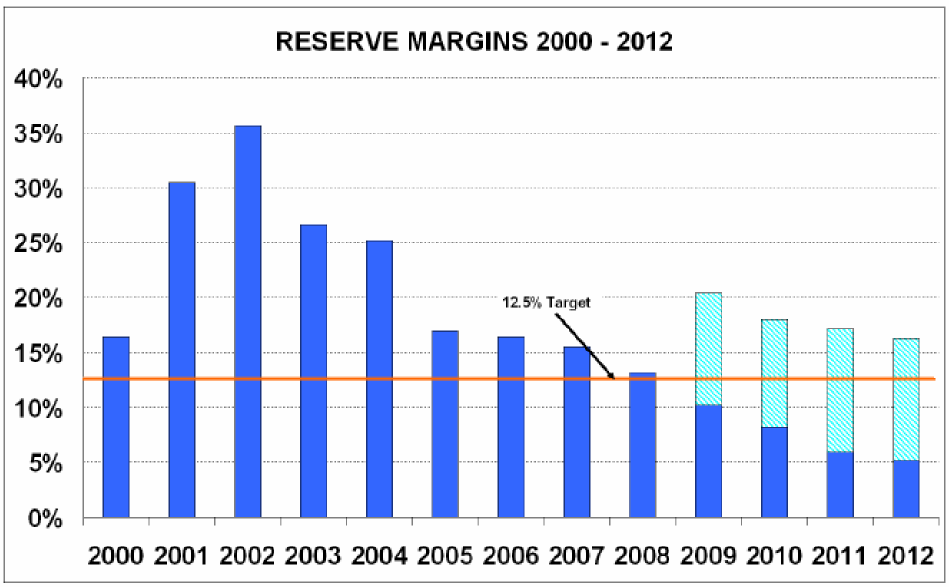
[6] Energy efficiency refers to using technologies that require less energy to meet a given level of energy services (hot shower, comfortable building, good lighting, etc.) while conservation refers to reducing energy service levels. For purposes of this report we will refer to energy efficiency and conservation as "energy efficiency."

[7] As a matter of both public policy and prudent operational policy, ERCOT requires that generation capacity in ERCOT exceed peak demand by 12.5% (the planning "reserve margin"). Reserve margins assure that there is enough generation available in real time—despite power plant, fuel availability, or transmission outages—to meet peak loads regardless of forecasting errors and a lack of demand-reducing mechanisms other than involuntary customer outages.

shortfall would not occur until 2009, as can be seen in Figure 1 (Jones 2007). Even with this delay, it will be a challenge for new generation to be constructed in time to meet this forecasted need. On the other hand, as will be discussed later in this report, energy efficiency and demand response can be quickly deployed, meeting this need in the short time available.

Many groups have also expressed concerns about the diversity of fuel mix in electric power generation (see Figure 2), which is very highly dependent on natural gas. Within ERCOT, at present almost 70% of installed generating capacity is fueled by natural gas; 19% is coal (some mined in-state and some imported from the Powder River Basin); 6% is nuclear; and 4% comes from wind, the state's fastest-growing generation source. A third of ERCOT's current power plant fleet has been built since 1999, and almost all of that capacity is natural gas-fired.

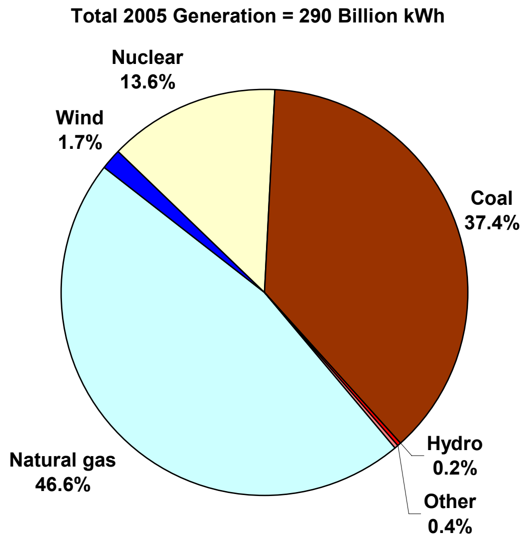
Figure 1. Actual and Projected ERCOT Reserve Margins



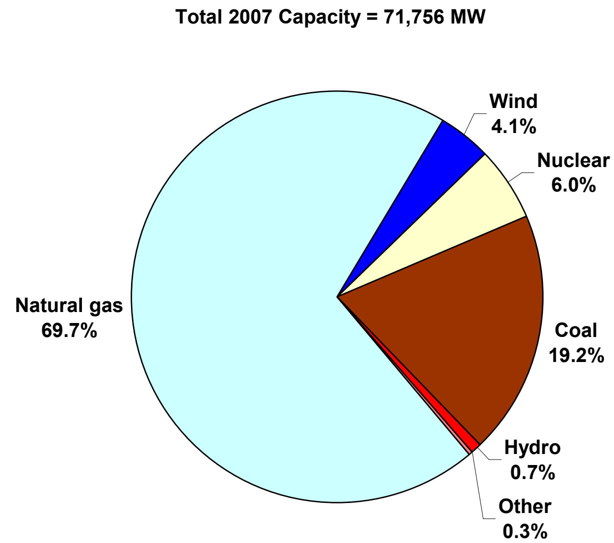
Source: Jones 2007
Note: Lighter shaded bars represent "mothballed" units—generating units that are currently out of service but could be returned to service if conditions warrant as defined in ERCOT (2006a).

The state's rapidly growing peak demand and electricity consumption, coupled with high electric rates, have led some of the state's energy planners to suggest taking actions to change the resource availability, including more coal-fired coal plants (ERCOT 2006a; Jones 2007). We suggest that a broad range of resources beyond new, conventional fossil-fueled generation need to be evaluated as the state decides how to meet its near and long-term energy needs. We will seek to characterize the potential for some of these key "alternative" resources in this analysis.

Figure 2. ERCOT Generation and Capacity by Fuel



Source: Jones 2006



Source: Jones 2007

Energy efficiency, demand response, and renewable energy resources represent the low-cost energy and capacity resources available to the state. Recently polling suggests that over 70% of Texans would be willing to support increased spending on energy efficiency by the electric utility industry (WRS 2007). Almost two-thirds of the respondents were willing to pay more on their electric bills today if it avoided high cost electricity in the future, so a core of public support for policies such as we propose in this study clearly exists in Texas.

Texas has already moved in this direction through its renewable energy portfolio standard (RPS) and its energy efficiency with its energy efficiency improvement program that directs transmission and distribution utilities to procure 10% of load growth from energy efficiency. Utilities have been able to meet their EEIP, and as noted above, the state already gets more than 4% of its electricity from wind, and is on track to exceed the levels in the RPS. However, there is much more that can be achieved from energy efficiency, conservation, and renewable energy resources. In particular, the level of savings that utilities can procure under the EEIP can be cost effectively increased from the current level to 50% of load growth, as will be discussed. In addition, the EEIP does not apply to electric cooperative ("coops") and municipal utilities ("munis") in the state. While some of these utilities are already leaders, all should contribute to meeting the state's needs. In addition to the EEIP, several other policies could provide more energy efficiency and conservation resources. The potential for onsite renewable energy generation is very large in Texas, particularly with future availability of advanced technology. This report estimates the size of the energy efficiency, conservation, and onsite renewable energy resources in Texas, and suggests a suite of policy options that the state can consider to realize their achievable potential. As this report will show, these resources can meet a growing share of the state's electricity consumption and peak demand needs at a fraction of the cost of new conventional fossil fuel generation, and can be deployed much faster. These resources will help to diversify the resource base while increasing system reliability compared with construction of major new conventional generation resources.

A significant opportunity also exists to expand the demand response in Texas to reduce system peaks, as has been called for by ERCOT (Jones 2007). The combined impact of demand response and the alternative resources described above can help to address the state's reserve margin concerns while insuring that the state has adequate, affordable electric resources to sustain its economic growth. This report will explore the opportunities that exist in Texas for additional energy efficiency, demand response, and onsite renewable energy, and the policies and programs necessary to realize these resources to meet the state's future energy needs.

Overview of Analysis

The remainder of this report is divided into three sections:

1. Overview of the reference case used for this analysis and how the results should be used;
2. An assessment of the economic potential for energy efficiency, combined heat and power (CHP), onsite renewable energy, and demand response; and
3. Suggestion of a portfolio of policy recommendations that could help realize the resource potential identified in the economic assessment, and projected impacts of these policies.

Details on the analyses and assumptions are included in the appendices along with the detailed results tables. A subsequent report will explore the macro-economic impacts of these savings, including the effect on the gross state product, employment, reduced energy expenditures, and energy price stabilization.

METHODOLOGY

We approached this analytical effort by building upon numerous other state energy efficiency resource assessments that ACEEE has undertaken over the past two decades. During these years we have developed a methodological approach as follows:

1. Based on available data, we first developed a set of reference projections for electric and natural gas consumption and demand, disaggregated by end-user category (e.g., residential, commercial, and industrial). We also incorporated estimates of energy prices and avoided utility costs (as discussed in the next section).
2. We then assessed the potential for energy savings and demand reduction within each sector, based on available technology performance and cost.
3. We applied the savings projections to the reference case to estimate the impact that efficiency and renewable resources could have on the state's energy future.
4. Finally, we designed a set of policy proposals that have achieved reliable results in other relevant state energy markets. From those other policy results, we

estimated the fraction of the potential savings that would be realized if these policies were implemented in Texas.

ACEEE's research has identified three general types of energy efficiency and renewable energy resource potential: technical, economic, and achievable.

- Technical potential represents what can be saved from available or emerging efficiency and renewable technologies and practices without regard to either the cost or the benefits of the measures.
- Economic potential represents the fraction of the technical potential that is cost-effective under a set of technology costs and full avoided costs developed for the period of analysis.
- Achievable potential represents the fraction of the economic potential that: (1) can be plausibly realized in the marketplace, given market constraints (e.g., equipment turnover rates) and the impacts of programs and policies that could be implemented; and (2) is cost-effective from the standpoint of direct electricity bill savings only. In other words, our estimates of achievable potential exclude the adoption of technologies based on non-energy productivity benefits or environmental externalities (see Worrell et al. 2003 for a review of the larger productivity benefits that might be generated from standard energy efficiency investments).

For the purposes of this study, we have elected not to develop an entirely new set of technical potential assessments, because numerous studies conducted by ACEEE and others have largely characterized the potential measures that are available in Texas. Bypassing this step allows us to focus on the more important economic potential and achievable potential estimates (see Nadel, Shipley, and Elliott 2004 for a more detailed discussion of these issues and past research).

With respect to the achievable potential estimates, we relied upon results from the best-practice programs and policies implemented in other states in recent years; these are discussed in the section on policy recommendations.

Energy Demand Reference Case

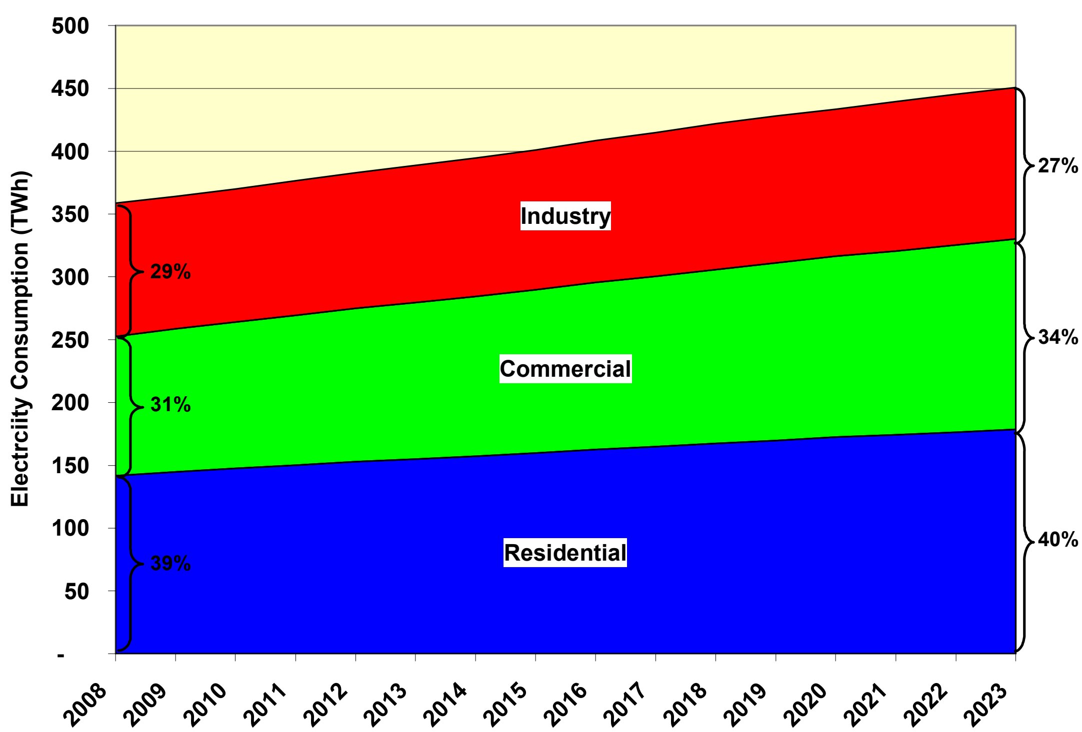
The first step to determine energy efficiency potential for Texas was to establish disaggregated reference case energy consumption and demand forecasts. There are currently no publicly available energy consumption forecasts that include both statewide and end-use sector (residential, commercial, and industrial) breakdowns. We used publicly available data from the U.S. Bureau of the Census (Census), the U.S. Department of Energy's Energy Information Administration (EIA), and ERCOT. We also purchased data from Economy.com (2007) for other economic information to produce the reference case forecast (see Table 1). Our reference case estimates future electricity demand in a "business-as-usual" scenario, which includes current utility efficiency efforts in Texas. **Error! Reference source not found.** shows the relative changes in projected consumption among the sectors, with a growing dominance by the commercial sector reflecting the very rapid growth in the commercial consumption, and the more modest growth in industrial consumption.

Table 1. Texas Reference Case Electricity Consumption and Demand Forecast

	2008	2013	2023	Average Growth Rate
Peak Summer Demand—All Sectors (MW)	75,668	84,850	105,874	2.26%
Residential	36,492	40,975	50,543	2.2%
Commercial	25,795	29,712	38,593	2.7%
Industrial	13,381	14,164	16,738	1.5%
Electricity Consumption—All Sectors (million kWh)*	358,459	388,647	450,718	1.5%
Residential	141,553	154,824	178,588	1.6%
Commercial	111,176	124,741	151,518	2.1%
Industrial	104,672	110,012	121,521	1.0%

* Residential and commercial sector consumption data is based on projections for ERCOT in EIA (2006a), adjusted to the entire state. Industrial sector data is based on EIA data for electricity sales and an average annual growth rate of 1% from Economy.com (2007). Due to the different data sources, adding consumption in each of the three sectors does not exactly equal the statewide total consumption forecast.

Figure 3. Reference Forecast for Electricity Consumption by Sector



For the peak demand (MW) reference case, we rely upon ERCOT's forecast (ERCOT 2006a). We adjust this to the entire state assuming that the ERCOT territory accounts for 85% of the electric load in Texas. The average annual growth rate for peak demand from 2008–2023 in the reference case is 2.26%. For the electricity consumption (TWh) reference case, we rely upon EIA's *Annual Energy Outlook 2006* energy forecast for the ERCOT region, which is disaggregated by sector (EIA 2006a). We then adjusted the forecast to the entire state assuming that ERCOT makes up 85% of the state's electricity load. See Table 1 for a summary of the reference case electricity consumption and demand forecasts by sector.

Residential Sector

We derived total electricity consumption in the residential sector from the EIA (2006a) forecast for the ERCOT region and then calibrated the total consumption to Texas by assuming that ERCOT makes up 85% of the state's electricity load. The growth rate in residential consumption is an annual average of 1.6%. Detailed information for the four most populous states, of which Texas is one, is available in EIA's *2001 Residential Energy Consumption Survey* (EIA 2001). The data includes statewide electricity use by end-use (space heating, air conditioning, water heating, etc.). We assumed that the fraction of energy consumed by each end-use would remain constant.

Commercial Sector

Energy consumption for the commercial sector was obtained using the same methodology as the residential sector. The EIA (2006a) ERCOT commercial electricity growth rate is 2.1%. Detailed information for consumption in the commercial sector with a breakdown by end-use was estimated using EIA's 1995 and 2003 *Commercial Building's Energy Consumption Surveys'* data for the West South Central region (EIA 1995; EIA 2003).

Industrial Sector

Comprehensive, highly disaggregated electricity data for the industrial sector is not available at the state level. To estimate the electricity consumption, this study drew upon a number of resources, all using the same classification system[8] and sample methodology. Fortunately, a conjunction of the various economic censuses for each state allows us to use a common base year of 2002. The major data source available for Texas was 2002 *Economic Census Subject Series for Mining and Manufacturing* (Census 2006).

Unfortunately, disaggregated state-level electricity consumption data was not reported for the sub-sectors (such as chemical, paper, primary metals industries, etc.). Because of the magnitude of and diversity in this manufacturing sub-sector, it is important to disaggregate beyond the sub-sector or industry group level (e.g., the fraction of pharmaceutical products in the chemicals industry). As a result, we used national industry electricity intensities derived from industry group electricity consumption data reported in the *2002 Manufacturing Energy Consumption Survey* (MECS) (EIA 2005) and the value of shipments data reported in the

[8] ACEEE's industrial analyses use the North American Industrial Classification System (NAICS) to disaggregate industrial sector economic activity and energy use.

2002 Annual Survey of Manufacturing (ASM) (Census 2005). These intensities were then applied to the value of shipments data for the manufacturing energy groups (three-digit NAICS) in Texas. These electricity consumption estimates were then used to characterize each sub-sector's share of the industrial sector electricity consumption.

Because state-level disaggregated economic growth projections are not publicly available, data was used from Economy.com (2007). The growth rate of industrial electricity consumption from Economy.com was applied to the base year (2002) disaggregated electricity consumption. These values were then calibrated to the 2005 industrial electric sales as stated in the 2005 *Electric Power Annual* (EIA 2006c).

THE POTENTIAL FOR COST-EFFECTIVE EFFICIENCY, DEMAND RESPONSE, AND ONSITE RENEWABLE ENERGY RESOURCES

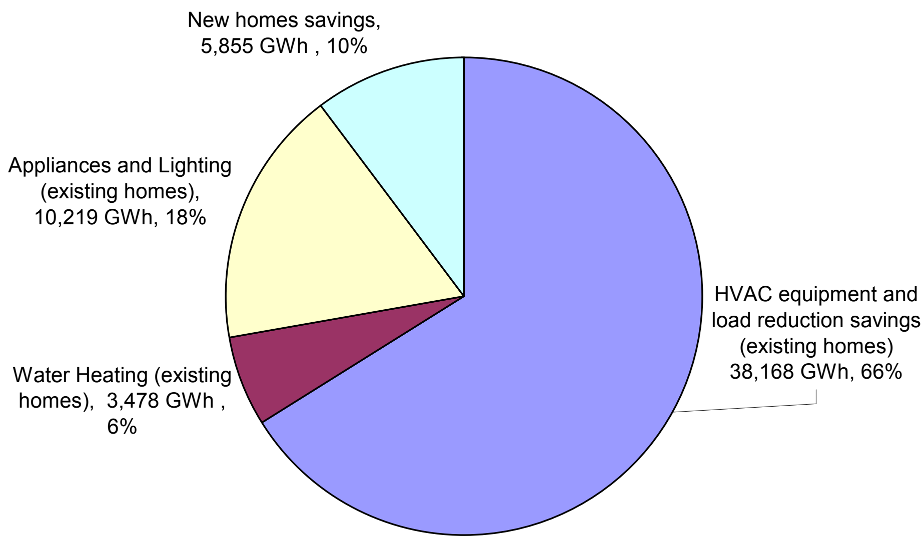
As noted above, the economic potential represents an assessment of the overall resource potential that exists from energy efficiency, demand response, and renewable energy, given an assessment of full benefits and full costs. In this section, we evaluate energy resources that are cost-effective, i.e., the dollar savings from reduced energy consumption or demand outweigh implementation costs. In general, experience with actual programs suggests that only a portion of this is realistically achievable in the real world from programs and policies (see Nadel, Shipley, and Elliott 2004). In the next section, we explore the fraction of this economic resource potential that can be realistically achieved through a suite of suggested policies, limiting our analysis to full policy and investment costs, but only direct electricity bill impacts or savings. This analysis does not take into consideration any externalities, such as avoided emissions, avoided future carbon control risks, health implications, or other indirect benefits of this deployment of these resources. If these costs were included, energy efficiency and renewable energy resources would be even more cost competitive with conventional fossil-fueled generation.

Residential Efficiency

To examine the economic potential for energy efficiency resources in Texas's residential sector, we considered a scenario with widespread adoption of cost-effective energy efficiency measures during the 15-year period from 2008 to 2023. We evaluated a number of efficiency measures that might be adopted in existing and new residential homes. The cost-effectiveness of measures was determined by having a levelized cost of less than 10.8 cents per kWh saved, based on current average residential electricity prices in Texas (EIA 2006b); however, the overwhelming majority (95%) of the total efficiency potential has a levelized cost of less than 8 cents per kWh saved and about half of the measures have a cost of 3 cents per kWh or less. See Appendix C for a detailed methodology and specific efficiency opportunities and cost-effectiveness for residential buildings (Table C.1).

In the residential sector, the major opportunities for electricity efficiency resources are improved housing shell performance (i.e., insulation measures, reduced air infiltration, ENERGY STAR® windows, etc.), which can reduce heating and cooling loads by about 53% compared to current average space heating and cooling household consumption, combined with more efficient heating, ventilation, and air conditioning (HVAC) equipment and systems.[9] As a fraction of total savings potential in the residential sector, these efforts to reduce cooling and heating loads and improve HVAC system performance in existing homes make up the majority—66% of potential savings (see Figure 4).

Figure 4. Fraction of Potential Savings by Residential Efficiency End-Uses in 2023



Total: 57,720 GWh
32% of Projected Residential Electricity Consumption in 2023

There is a large potential for efficiency resources in both existing and new homes in Texas by replacing regularly used household incandescent light bulbs with more efficient compact fluorescent light bulbs (CFLs). A recent TXU baseline survey of new homes found that the more efficient CFLs account for only 1.5% of all installed lighting fixtures (RLW Analytics 2007). Incandescent lamps make up about 95% of lighting fixtures. More efficient appliances can also yield significant savings by homeowners choosing ENERGY STAR® models upon replacement of refrigerators, clothes washers, and dishwashers, and builders installing these more efficient models in new homes. Together, savings from more efficient lighting and appliances in existing homes make up 18% of the total residential efficiency potential. Measures to reduce hot water loads (such as high-efficiency clothes washers, low-flow showerheads, and water heater jackets and pipe insulation) can yield additional savings for households with electric water heaters. The use of more efficient water heaters, such as high-efficiency electric water heaters and heat-pump water heaters, can further reduce electricity used for water heating. Solar hot water heating, which also has significant potential in Texas, is addressed in the Onsite Renewables section.

[9] Savings from air-conditioners assume a baseline of 13 SEER equipment, which is the recently updated federal standard.

We estimate an economic potential for efficiency resources of about 57,720 GWh in the residential sector in the 15-year period of 2008–2023, or a savings of 32% of the reference case electricity consumption in 2023. Existing homes can reduce electricity consumption by about 29% through the adoption of a variety of efficiency measures (see Appendix Table C.1). New homes built today can readily achieve 15% energy savings (ENERGY STAR® new homes meet this level of efficiency) (Haberl et al. 2005) and according to an analysis by Texas A&M University, homes can cost-effectively reach 50% energy savings (Malhotra and Haberl 2005). We estimate that new residential homes can yield electricity savings of about 5,855 GWh by 2023, or 10% of total potential savings in the residential sector. See Figure 4 for a breakdown of potential efficiency resources by end-use.

Commercial Efficiency

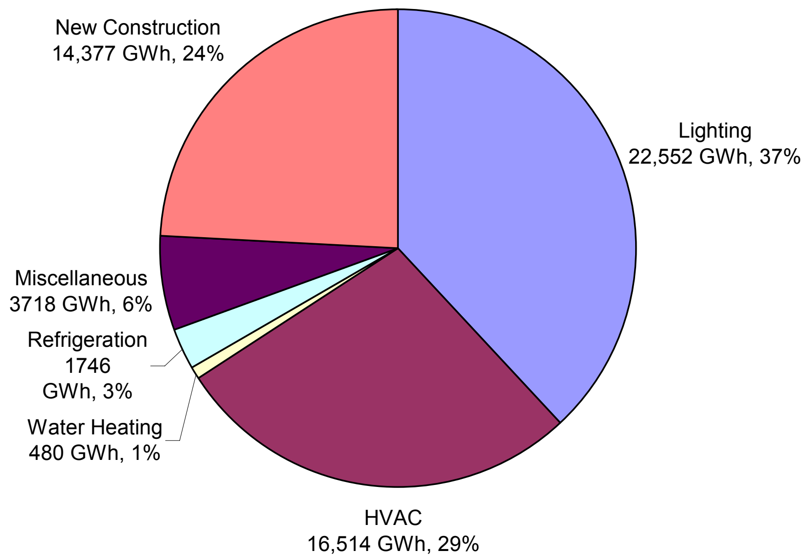
We analyzed the economic potential for energy efficiency in the commercial sector in a similar manner as the residential sector, evaluating 35 efficiency measures. The cost-effectiveness of measures was determined by having a levelized cost of less than 8.85 cents per kWh saved, based on current average Texas commercial electricity prices (EIA 2006b); however, the overwhelming majority (98%) of efficiency potential has a levelized cost of less than 5 cents per kWh saved. See Appendix C for a detailed methodology and specific efficiency opportunities and cost-effectiveness for commercial buildings (Table C.2).

Greater electricity efficiency resources exist in existing commercial buildings through more efficient lighting, HVAC equipment and systems, high-efficiency refrigeration, and water heating equipment and systems. Lighting systems are the greatest end-use of electricity consumption in commercial buildings in Texas, accounting for about 43% of all electricity consumption. A number of efforts to increase the efficiency of these systems (including fluorescent lighting improvements, replacing incandescent lamps with compact fluorescent lamps, daylight dimming systems, and others) can reduce electricity consumption for this end-use by nearly 35%, creating an energy resource of about 22,552 GWh by 2023.

A combination of replacing HVAC equipment (such as chillers, fans, and packaged air-conditioning units) with more efficient units, testing and sealing air distribution ducts, and reducing HVAC loads with more efficient windows, roof insulation, and cool roofs can lower HVAC electricity consumption by 39%. Installing more efficient refrigeration systems and replacing inefficient office equipment with more energy-efficient products can add additional savings. Together, these measures to reduce HVAC electricity consumption create a resource of about 16,514 GWh by 2023, 29% of the total savings potential.

We estimate that when these measures are implemented together, electricity efficiency resources in existing commercial buildings in Texas can reach nearly 46,000 GWh in the next 15 years, or 30% of projected electricity consumption in 2023. Efficiency reductions in new commercial buildings provide a resource of about 14,377 GWh by 2023, or 24% of the total savings potential. In the commercial sector, we estimate a total untapped economic efficiency resource potential of about 59,000 GWh, or 39% of projected electricity consumption in the commercial sector in 2023. See Figure 5 for the fraction of total savings by end-use.

Figure 5. Fraction of Potential Savings by Commercial Efficiency End-Use in 2023



Industrial Efficiency

A significant efficiency resource potential exists in the industrial sector, representing perhaps one of the lowest cost energy resources available in the state. In 2004, Texas's industrial sector consumed 100,588,036 MWh of electricity. Within the manufacturing sector, chemical manufacturing (NAICS 325) dominated at 39% of the electricity use, with petrochemical production the state's largest industrial electric energy user. Petroleum products, computers and electronics, and primary metals followed at 18%, 13%, and 8%, respectively, of electricity use.

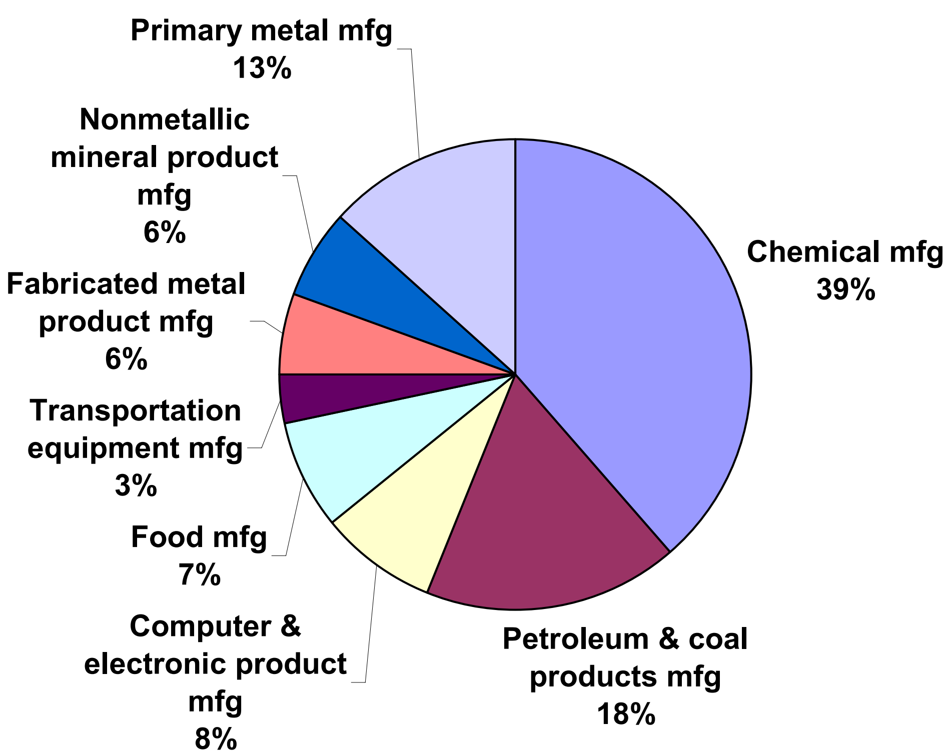
The estimation of the electricity efficiency resource potential is accomplished in a series of steps. First, the industrial electricity market in Texas is characterized. Then energy-saving technologies for analysis are identified based on prior ACEEE analyses, and the economic potential is estimated based on these measures. Twenty-one distinct measures and measure bundles were analyzed (14 of which were cost-effective, with a cost of saved energy under $0.08/kWh saved, with 12 at $0.03/kWh saved or less) across twenty-two industrial sub-sectors for the Texas industrial sector. The measure bundles are presented in Table 2.

This analysis estimates the economic efficiency resource potential for the industrial sector to be roughly 26%. The savings can be broken down by industry type as presented in Figure 6.

Table 2. Industrial Energy Efficiency Measure Bundles

Measure	Cost of Saved Energy ($/KWh saved)	Percent Savings Attributable to each Individual Measure	Economic Savings Potential (% of Total Industrial Electricity Potential)
Sensors and controls	0.02	1.4%	5.8%
Energy information systems	0.08	1.4%	5.8%
Pipe insulation	0.065	4.1%	16.7%
Electric supply improvements	0.01	4.0%	16.5%
Lighting	0.03	3.4%	13.7%
Motor design	0.03	3.8%	15.6%
Motor management	0.02	0.7%	2.7%
Lubricants	—	0.6%	2.3%
Motor system optimization	0.01	0.4%	1.5%
Compressed air management	—	2.1%	8.6%
Compressed air—advanced	0.00	0.1%	0.4%
Pumps	0.01	2.9%	11.7%
Fans	0.03	0.7%	3.0%
Refrigeration	0.00	0.4%	1.4%
TOTAL		25.8%	100%

Figure 6. Fraction of Potential Savings by Industry Type



Demand Response

Background—Demand Response in ERCOT

The DOE defines demand response as: "changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized." (DOE 2006b). Demand response measures include incentive-based programs that pay users to reduce their electricity consumption in specific times (such as load management and direct control to turn down customers' heaters or air conditioners in an emergency situation), or pricing programs such as time-of-use rates, critical peak pricing, or real time pricing, where customers are given a price signal and expected to moderate their electricity usage in times when prices are high. Most early demand response programs were incentive-based and control-oriented, so the utilities could operate and control the customers' usage and tell exactly when and how much load changed; these are viewed as reliable, predictable programs that can be trusted as a resource to meet grid reliability needs.

Over the near term, given Texas's tight capacity situation, incentive-based, emergency-oriented demand response programs will be most effective at lowering effective peak loads and moderating supply scarcity. Over the long term, however, once ERCOT's nodal market is in full operation and many ERCOT retail electric consumers have advanced interval meters, more customers should and could take advantage of time-varying rates such as critical peak pricing, and price-responsive demand response should have a far greater impact upon peak loads and prices than incentive-based programs. Today we have no data to estimate the possible impact of time-varying rates upon electricity consumption, and it will take years to collect and analyze such data; therefore, this study estimates only the potential for incentive-based, emergency-oriented demand response measures upon ERCOT's supply-to-demand balance. By 2023, however, it is possible that the widespread availability of time-varying retail electric rates and complementary communications and control methods will have permanently changed the nature of Texas's electricity demand, making today's forecasts for ever-increasing demands obsolete.

The ERCOT market began wholesale competition in 1995 and retail competition in 2002. Before the start of retail competition, Texas's integrated utilities offered a variety of direct load control and time of use, curtailable, and interruptible rates, with almost 3,500 MW of loads participating (primarily from Texas's base of industrial facilities). However, with the advent of retail competition in ERCOT and the structural unbundling of the investor-owned utilities, much of this demand response capability was lost to new market complexities and higher transactions costs.

There is less demand response available in ERCOT today, and in more limited forms than were available before competition. ERCOT has a real-time energy market (and no capacity market), and customers with loads at or above 700 kW have interval data recorders (meters that record energy use over time). The following types of demand response are in use today:

- *Load acting as a Resource (LaaR) serving as Responsive Reserve*— There is 1,150 MW of Responsive Reserve (the maximum currently allowed in the market for this product at any point in time), although 115 customers (all large industrial users, like petrochemical plants) offering 1,875 MW are registered as qualified LaaR providers. These customers drop load either automatically when the bulk power system needs it for frequency restoration (triggered automatically by under-frequency relays at the customers' sites) or upon request by ERCOT. LaaR is bid into the Responsive Reserve market. In 2006, LaaR provided 10,055 GWh in load capacity to respond to system emergencies and received $48.4 million in payments (Krein 2006). In late 2006, the average price paid for Responsive Reserve Service was about $13.00/MW.

- *Voluntary Load Response*—It is estimated that more than 600 MW of large industrial and commercial customers have contracts with their retail electric providers (REP) to lower their electric load upon request. The contract between the customer and the REP may or may not offer an extra incentive for the peak load reduction, which helps the REP manage its energy purchase portfolio and costs. ERCOT transmission charges for one year are based on grid users' maximum demands during the monthly coincident peaks in June through September. Therefore, several retail electric providers give warnings to their commercial and industrial customers to lower load on days in those months when a coincident peak is likely to occur. They do so because the value of avoided transmission charges can exceed $2,500 per MW in one 15-minute period if it is one of the four monthly coincident peaks—i.e., transmission charge avoidance is worth significantly more than the avoided energy costs. This is voluntary or contractual behavior that is not tracked or formally recognized as an ERCOT resource.

- *Active Price Response*—No compiled data exist on how many customers within ERCOT are actively monitoring ERCOT's 15-minute energy price feed and responding to price levels in real time. Research by Zarnikau et al. (2005) of the largest industrial energy consumers in Houston indicates that only two out of twenty were actively managing their loads in response to prices. Before 2006, among the retail competitive loads, only customers with loads greater than 700 kW had interval data recorders that could track time-varying energy uses, so the pool of customers with both the capability and sophistication to do so was limited.

- *Muni and Coop Demand Response programs*—ERCOT's municipal and cooperative utilities, which are not subject to retail competition and are outside the regulation of the Public Utility Commission of Texas (PUCT), offer more demand response program options than do the competitive retail electric providers. Several of the munis offer time of use rates and direct load control programs, while many of the rural coops offer direct load control for irrigation pumping and other uses.

- *LaaR Serving as Non-Spinning Reserve*—although ERCOT allows demand resources to compete against generators to provide non-spinning reserve, as of mid-2006 few end-users were actually providing this service. For 2005, LaaRs provided less than two percent of non-spinning reserve sales; one ERCOT observer remarked that "providing responsive reserves offers substantial revenue with very little probability of being deployed [but] providing non-spinning reserves introduces a much higher probability of being curtailed."

- *Balancing-Up Load*—Although ERCOT has defined the rules for customers (through Qualified Scheduling Entities) to bid their loads into the real-time energy market, only one customer has qualified to do so at present. Principal reasons given for the lack of BUL participation are that most of the potential participants are already committed to provide Responsive Reserve (LaaR) service, and that prices in the balancing energy market are not high enough to attract load participation.

While the ERCOT market differs from other regions in many respects, three particular institutional factors affect the types of demand response offerings possible in ERCOT. First, the PUCT has made a policy decision that ERCOT will remain an energy-only market; in most other regions and wholesale markets, capacity payments ($/kW of load relief at a specific point in time) provide a supplemental stream of revenues to demand response and peak generators, on top of energy payments ($/kWh sold). As in other regions, spot market prices are subject to active market mitigation that distorts real-time price signals, although the level of the relevant price caps is rising over time. Second, since vertically integrated utilities were unbundled before the start of retail competition in ERCOT in 2002, the benefits of demand response are diffused and spread across multiple layers of beneficiaries, making it difficult to establish cost-effectiveness and reap the monetized benefits from demand response in the same way that a vertically integrated utility can. Last, retail electric companies are largely unregulated, so the Commission cannot dictate their pricing or rate offerings.

To estimate the potential for increased demand response in Texas, this analysis makes very limited assumptions with respect to what demand response mechanisms will be used over the forecast period. For residential customers, we assume that their only demand response option will be direct load control over air conditioning, with one additional appliance, to be cycled on and off each hour during the needed period. This assumes that beginning in mid-2008, all new residential construction in Texas is required to install a smart, two-way communicating thermostat that can receive load control signals (similar to those under development in California), and that increasing numbers of such devices are installed and used over time under TXU-managed demand response programs. For commercial and small industrial facilities, we assume that they use energy management systems that can reduce on-peak demand by at least 5% per site in the early years, and 20% per site by 2023,[10] and that new non-residential construction is mandated to install and use

[10] The Lawrence Berkeley National Laboratory's Demand Response Research Center's reports indicate that automated demand response for commercial customers has delivered 5–10% peak load reductions in medium-sized commercial sites; this is confirmed by Southern California Edison research, which has achieved up to

energy management systems beginning in mid-2008. For industrial sites, we assume that ERCOT and the PUCT will increase the amount of Load as a Resource allowed for use as Responsive Reserve. Additionally, ERCOT and the PUCT will create some mechanism to allow the remaining LaaR customer load to offer their reductions into the market when needed (rather than only as emergency responsive reserve), and that more customers will voluntarily reduce their load to avoid transmission charges.

Since air conditioning direct load control has already been used extensively within Texas by the City of Austin, City Public Service of San Antonio, and Houston Light & Power (although that program has since been abandoned due to retail restructuring), and is widely used and being expanded in Florida, California, and other states, it is clear that this technology is cost-effective today. The challenge in ERCOT is not with the low cost of such options, but whether and how to apportion the benefits and costs of demand response when there is no vertically integrated utility to internalize the benefits; we recommend that since all of Texas's electricity customers ultimately benefit from demand response (even if those benefits cannot be fully monetized by any one market participant), the costs and the burden of program delivery should be placed upon the transmission and distribution utility since it serves all end-users. Similarly, the other demand response methods included in these calculations are already in commercial use in Texas and elsewhere, and therefore are by definition cost-effective.

Using these limited program assumptions with conservative penetration and impact rates (as shown in Appendix E), we estimate the following load reductions from the reference case due to demand response:

- in 2013, 1,549 MW from residential users, 1,289 MW from commercial users, and 1,020 MW from industrial users, totaling 3,463 MW and 4.1% of peak load; and
- in 2023, 5,540 MW from residential users, 6,551 MW from commercial users, and 1,150 MW from industrial users, totaling 13,241 MW and 12.5% of peak load.

Combined Heat and Power Systems

Combined heat and power, also know as cogeneration, involves co-production of two or more usable energy outputs (e.g., electricity and steam) from a single fuel input. By harnessing much of the energy normally wasted in power-only generation, significant improvements in efficiency can be realized relative to separate production of power and thermal energy (see Elliott and Spurr 1999).

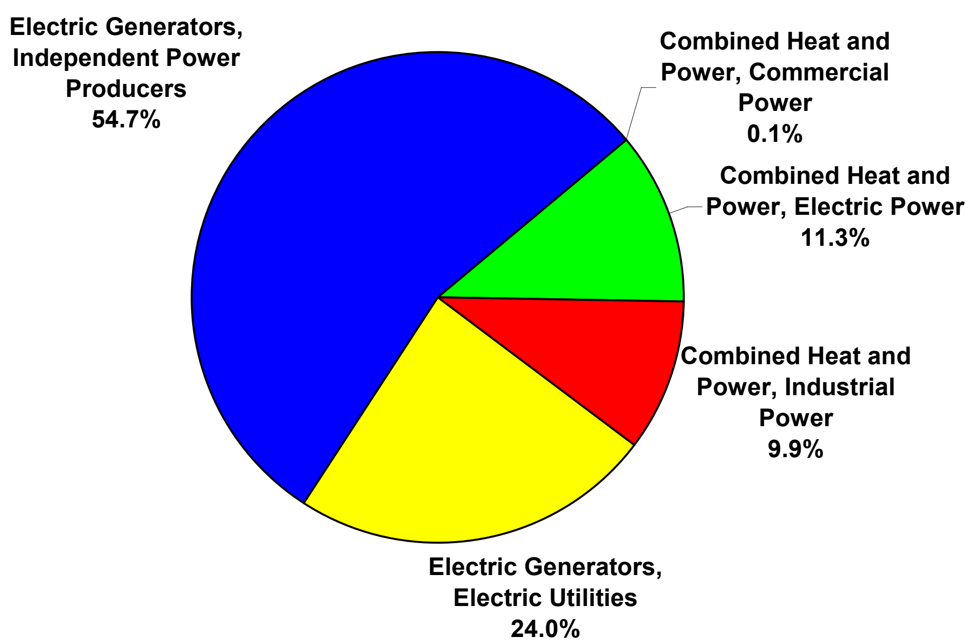
In many ways Texas is the CHP capital of the United States, accounting for about a quarter of the total electricity generated by CHP in the country. In 2005, over 21% of the electricity generated in Texas came from CHP systems, compared with a little over 8% nationally. As can be seen in Figure 7, the CHP generation is fairly equally distributed between industrial-owned and independently owned cogeneration facilities, with a very low

25% demand reductions for small commercial customers. Site Controls, a Texas-based energy management company, is delivering sustained peak load reductions of over 30% to its small commercial customers using technology that is commercially cost-effective today.

level of institutional and commercial CHP facilities. Between 1999 and 2005, the share of the state's overall generation from CHP increased by almost 20 million MWh or 29%, while total generation increased by only 11%. Almost all of that increase was in the independently owned facilities. While the increase in independent CHP was rapid in the early part of this decade, the growth has stalled in the past few years as high natural gas prices have made CHP less attractive (EIA 2007).

While Texas has already implemented significant CHP, significant opportunities remain for even more CHP. A 2001 report (Elliott and Hedman 2001) identified particularly significant opportunities in the commercial and institutional sectors, and identified additional industrial capacity potential. Energy and Environmental Analysis, Inc. (EEA) updated that analysis for this report and included an assessment of the potential for thermally activated cooling with CHP systems. With thermally activated cooling technologies, such as absorption refrigeration, power and cooling are both produced by the CHP system. This application has the benefit of producing electricity to satisfy onsite power requirements and displacing electrically generated cooling during periods of peak demand (see Elliott and Spurr 1999).

Figure 7. 2005 Electric Generation in Texas by Type of Producer



Source: EIA 2007

We estimate that a technical potential of almost 14,000 MW of additional CHP still exists in the state of Texas by 2023. With appropriate market and policy forces, our analysis estimates that almost 1,900 MW of additional CHP capacity would be economically achievable in 2023 at current fuel and electricity prices, without incentives. Were incentives on the order of $600/kW provided for the installation of CHP systems (far less than the cost of any new generation technology), the economic potential would increase by almost 50%.

The potential peak reductions in 2023 from the capacity would be over 1,750 MW[11] from the electric generation and an additional 29 MW from the displaced electric cooling, with a combined potential to displace grid electricity of almost 15 billion kWh. In 2010, over 520 MW of peak load and almost 4,200 million kWh of generation could be displaced by CHP. For details on the estimation of the technical and economic potential for CHP, see Appendix E.

Onsite Renewables

Background for Economic Potential

The technical potential for onsite renewable energy utilization is staggering, far greater in fact than total energy consumed in Texas. The accessible levels of solar, wind, biomass, geothermal, and water-based renewable resources throughout Texas provide more than 250 Quads of usable potential every year (about 20 times current energy consumption in Texas) (VERA 1995). The ability to harness this vast pool of natural energy at locations where Texans consume energy is a function of the status and cost of renewable energy conversion technologies, which differ significantly depending on resource.

As a general rule, as renewable energy technologies mature, they will increasingly penetrate the market and deliver environmental and cost benefits to consumers. This derives from the historical fact that renewable energy costs are trending downward, while conventional energy and environmental compliance costs are trending upward. When considered through a life-cycle cost assessment, new renewables will be more cost effective than conventional energy sources well in advance of the time the current-year prices of renewable and conventional technology achieve parity. On the other hand, the reality of market inertia will delay significantly the rate at which new technology and market options are adopted, even when the new options are clearly superior. Incentives are an appropriate public policy endeavor to hasten the transition toward energy options that can provide societal and consumer economic and health benefits.

<u>More Stimulus, More Results:</u> Germany—a nation with a land area about 50% the size of Texas and with a peak electrical demand approximately 10% larger than Texas—has made significant and steady progress deploying renewables during the past 15 years, such that renewable energy now produces more than 10% of Germany's electricity. These results stem from a major commitment to effective and well-funded incentives. Germany's diversified renewable energy programs in 2005 resulted in $9 billion in construction of new plants and $7.4 billion in operation of plants, and accounted for 170,000 jobs (Staiss et al. 2006). These results have been achieved despite Germany's mediocre renewable resource availability, which is dramatically less than resources in Texas. Solar radiation in Germany is about 60% of that for most Texas cities, while on a per MW basis, a new wind project in Texas produces fully twice as much electric output as the typical wind facility in Germany. The German experience suggests that Texas could achieve extraordinary success through a long-term, sustained financial commitment to onsite renewable generation technology. While possible,

[11] We assume that each kW of capacity reduces summer peak demand by about 0.95 kW.

such substantial incentives for renewable energy technologies have not historically been undertaken in Texas.

Overview of Onsite Renewable Energy Technologies

The principal onsite renewable generation options in Texas are described below in relation to their potential market through 2023, if promoted and incentivized effectively.

Distributed Onsite Wind: Large-scale wind power technology has been very successful in Texas as a new source of bulk generation, growing from 0 to 2,768 MW in 11 years, which is sufficient for Texas to overtake California as the nation's #1 wind power producer. Distributed wind generators using large-scale equipment have also recently begun to demonstrate viability in Texas, with 10 MW in 2005 and 40 MW in 2006. Distributed onsite wind, which as used here implies large commercial wind turbines installed for the direct use of industrial, institutional, or commercial customers, has tremendous potential for significant near-term energy savings. Onsite wind potential is estimated at 7,500 MW, a modest subset of the more than 500,000 MW of total wind potential across the state and about half of the approximately 15,000 MW of fossil generation already used by large industrial energy consumers in Texas.

Biomass: Texas has a very large, diversified and geographically dispersed agribusiness sector. High conventional energy costs are stimulating keen interest in new energy generator installations using bioenergy resources, such as at confined animal feeding operations (CAFO), timber and pulpwood mills, and facilities using any of a wide variety of agriculture and food processing waste feed stocks. This sector represents the greatest near-term potential for peak demand reductions, particularly in the timber and wood products industries. In the foreseeable future, biomass gasification could open the door to much greater opportunities for small biomass in Texas. Any policies developed to promote bioenergy use must balance the potential environmental ramifications of increased use and satisfy the requirements of a Standard Permit by Rule or BACT. The economic potential for onsite use of bioenergy feedstocks in Texas could exceed 10,000 MW;[12] however, these feed stocks, which can be readily stored and transported, may instead be used in large central station bioenergy facilities or converted into liquid bio-fuels.

Photovoltaics (PV): Solar energy is available in commercially viable levels throughout the entire state and offers unparalleled long-term potential for Texas. PV are already cost-effective for serving many remote and small loads throughout Texas, but compared to the average cost of grid-supplied power, PV is currently more expensive. Due to PV's statewide applicability, extreme versatility, and unlimited potential, and the prospect of providing a highly desirable emission-free, onsite generation source for congested urban settings, special consideration of incentives for PV is warranted. The technology has demonstrated consistent cost reduction as investment and experience have continued. More than 6 billion sq. ft. of suitable, existing rooftop area in Texas is estimated to be capable of supporting more than 60,000 MW of PV capacity (Navigant 2004). High value installations adjacent to buildings such as covered patios and parking structures add significantly to the potential suitable area

[12] According to TAMU, manure resources throughout Texas are equivalent to 2% of total energy use.

for onsite PV. One assessment of the potential demand for PV in Texas in 2010, under a cost breakthrough scenario, estimated a range of 33 MW/year @ $4.25–5.30/Watt to 727 MW/year @ $1.00–1.25/Watt) (Navigant 2004). (For perspective, Germany installed approximately 620 MW of PV in 2005 under their long-term regime of solar incentives.)

Solar Water Heating: Perhaps the oldest energy form known to man is the direct use of the heat of the sun. Today, advanced technologies are capable of producing solar-heated water for many purposes, ranging from air conditioning and industrial processes to domestic dishwashing and showers. Basic solar thermal technologies are suitable for application throughout the state for supplying building energy needs. Additional thermal technologies, including geothermal, are viable for use in Texas but are omitted from this report since they are already participating in state energy efficiency programs. A key need for all thermal technologies is to boost training of workforce and inspectors and stimulate market transformation of this overlooked technology.

Small Onsite Wind: Robust, low-maintenance wind technology for residential, ranch, and small commercial applications differ considerably from its large commercial counterparts. Whereas a typical 2 MW commercial wind turbine produces enough energy for 450 Texas houses, small wind technology is available in sizes that typically range from 0.3 to 50 kW. Many new products are under development for a broader range of applications, including urban environments. Small wind is expected to start at a modest level, but rapidly expand. Approximate 2 million household are projected to be candidates for small wind technology, yielding a potential estimated to be equivalent to 5,000 MW.

POLICY POTENTIAL FOR EFFICIENCY, DEMAND RESPONSE, AND ONSITE RENEWABLE ENERGY

As the previous analysis suggests, there are significant alternative resources available to Texas to meet the growing demand for electricity needed to sustain economic growth and meet the rapid increases in peak demand in the near and longer term. We have assembled a portfolio of nine policies that our analysis suggests are both effective and potentially politically viable in Texas:

1. Expanded Energy Efficiency Improvement Program (EEIP)
2. New State-Level Appliance and Equipment Standards
3. More Stringent Building Energy Codes
4. Advanced Energy-Efficient Building Program
5. Energy-Efficient State and Municipal Buildings Program
6. Short-Term Public Education and Rate Incentives
7. Increased Demand Response Programs
8. Combined Heat and Power Capacity Target
9. Onsite Renewable Energy Incentives

These policies have proven effective and economic in other states, compared with investments in conventional fossil-fueled generation, and would establish a foundation for a sustainable energy future while bolstering Texas's economic health. Additional policies are available and proven that would yield even greater impacts, but the authors did not feel that these policies would prove viable in the current political environment in Texas.

In the remainder of this section we describe each policy recommendation, recommend steps the state should take to implement these policies, estimate the electricity and peak-demand reduction impacts that could be achieved, and provide estimates of the costs from these policies.

Following this report, a subsequent analysis will estimate the statewide economic impacts of the recommended energy efficiency policies using ACEEE's macroeconomic DEEPER model (Laitner 2007a). The forthcoming analysis will estimate the projected net impact on consumer energy expenditures and gross state product (GSP), and assess the relative impacts on employment for the state. A previous study of energy efficiency and renewable energy in Texas found that investments in efficiency resulted in significant net new jobs relative to the investments in the same level of new conventional generation. These benefits result from the cost savings to consumers allowing them to re-spend the savings locally, creating new economic benefits (Goldberg and Laitner 1998). Similar conclusions are reported in the National Action Plan for Energy Efficiency, published by the U.S. Environmental Protection Agency, U.S. Department of Energy, and the National Association of Regulatory Utility Commissioners.

The forthcoming analysis will also explore the impact of reduced consumption on electricity prices. The DEEPER model generally provides results that are consistent with a large number of past state policy assessments (Laitner 2007b). Previous research has shown that in tight markets, small changes in energy demand can have large impacts on energy prices, particularly for natural gas (see Elliott and Shipley 2005; Elliott 2006; and real and modeled results within the 13-state PJM electricity market). While we anticipate that we might see a small decrease in energy savings as a result of a small rebound effect (the result of both reduced energy prices and a slightly increased income within Texas), we also anticipate a significantly greater dollar savings that consumers and businesses would experience as a result of price reductions.

Summary of Achievable Potential

If all the recommended policies were implemented, the state could meet all of its projected growth in peak demand between 2008 and 2023 through increased demand response, energy efficiency, and renewables (see Figure 8). The state could reduce its projected future use of electricity from conventional sources (i.e., natural gas, coal, oil, and nuclear fuels) by almost a quarter in the next 15 years (see Figure 9), again meeting all the projected growth in electricity consumption, and then some.

As can be seen from Figure 9, efficiency and CHP contribute the greatest savings, at over 80% of the 101,091 million kWh 2023 savings. Onsite renewable policies account for about 20% of the total 2023 electricity reductions.

Figure 8. Impact of Recommended Policies and Programs on Texas Peak Demand

Total 2023 Savings = 34,769 MW

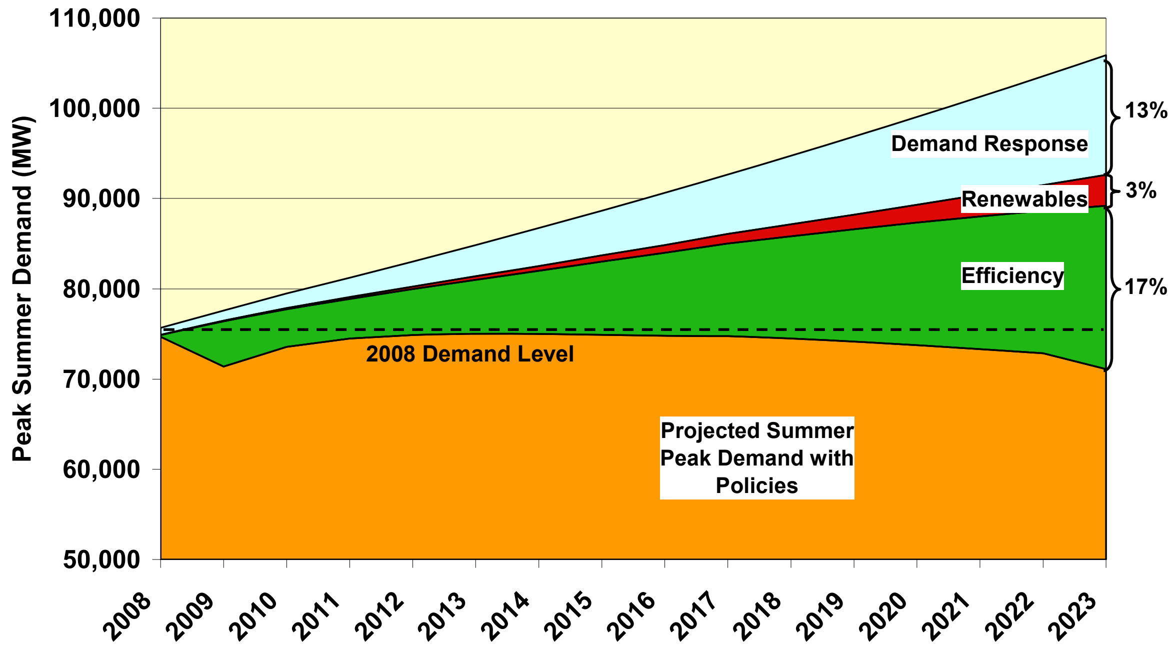
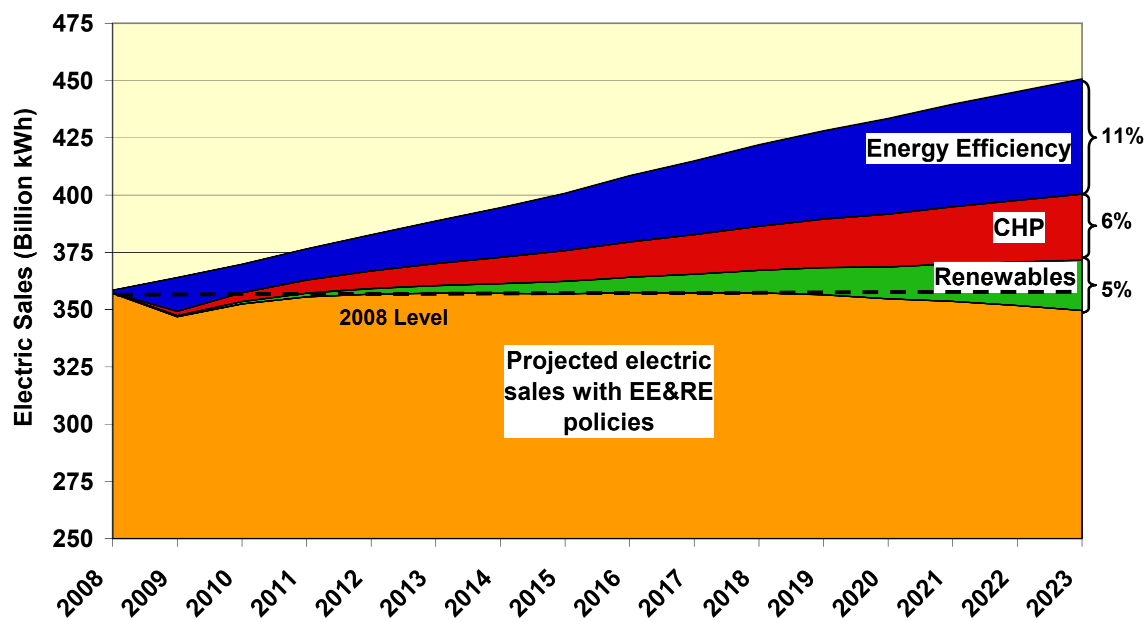


Figure 9. Impact of Energy Efficiency and Renewable Energy Policies on Texas Electricity Sales

Total 2023 Savings = 101,091 Million kWh



The most significant energy efficiency recommendations are for (1) an expanded Energy Efficiency Improvement Program, a utility savings target similar to the RPS concept, which accounts for about 30% of the total savings, and (2) improved CHP policies, which also account for 30% of total savings; these are discussed later in this section. As would be anticipated because of the importance of buildings-related electric loads, buildings policies (including an improved building energy code and advanced-buildings policies) contribute another 19% toward the total.

These policies can also reduce peak summer demand for electricity by 19%, not including demand resource programs discussed later in this report. The investments required and savings benefits from each policy recommendation are presented at the end of this section.

Energy Efficiency and Conservation Policies

Expanded Energy Efficiency Improvement Program

Since the passage of Texas's electric industry restructuring law, Texas utilities have been required to operate programs that reduce load growth by at least 10% annually. This requirement ramped in over a two-year period. This policy model has come to be known as an "Energy Efficiency Improvement Program." In recent years, Texas utilities have not had difficulty meeting this goal. For example, in 2005, savings totaled 13% of load growth (Nadel 2006). In recent years, load growth in Texas has averaged about 2% per year, and thus the current requirement means savings of about 0.2% of demand annually. By way of comparison, many other states are achieving much greater savings. For example, in Vermont, utility-sector programs have been reducing electricity by about 1% annually and a funding increase was recently approved that will bring annual savings to more than 2% of sales. Connecticut is now targeting savings of more than 1% per year under new targets enacted by the legislature in 2005. And in California, the Utility Commission has set 10-year targets of about 1% savings annually (Nadel 2006). Based on this experience elsewhere, we believe it is reasonable to quadruple or quintuple the Texas target to 40–50% of load growth. Such a target will place Texas among the leaders, but still a little behind the most aggressive states. To be conservative, for our savings projections, we assume a target of 50% of load growth, which requires an additional 40% savings on top of the current 10% annual target. This is in line with a recent petition to the Public Utility Commission of Texas by Efficiency Texas.

Currently, Texas energy efficiency programs are limited to a list of standard performance contracts for specific efficiency measures, plus a few "market transformation" initiatives. The programs are administered by the transmission and distribution utilities and delivered to customers by third-party providers (energy service companies). Only the regulated transmission and distribution utilities, which account for about 80% of electric sales, have been under the obligation to comply. In order to dramatically increase the savings targets, these restrictions will need to be lifted so that all cost-effective efficiency investments can be pursued, and that non-participating utilities be encouraged to meet these targets. Likewise, the current program rules cap the incentive levels that utilities can provide to project sponsors to a percentage of a proxy avoided cost. For example, a utility is allowed to pay incentives equal to no more than 35% of avoided cost for an energy efficiency project at the premise of a large commercial or industrial energy consumer and 50% at the premise of a residential consumer who does not fall into the "hard-to-reach" category. While one-third is a reasonable guideline for many programs, for some programs higher incentives may be justified, particularly when new measures are first being added and before local contractors are familiar with them. Therefore, we recommend that the current limits on incentives be raised and that the utilities be given flexibility to adjust incentive levels as necessary to meet program goals.

One other consideration for utility-sector programs is that for programs to work, the utilities running the programs need to want them to work. For reasons too complicated to go into here, often a successful utility energy efficiency program can have a negative effect on utility profits. To address this problem, quite a few states have adopted incentives for utilities that achieve energy saving goals and/or other mechanisms to assure utilities that effective efficiency programs will not cut profits. More information about these approaches can be found in an ACEEE report published in late 2006 (Kushler, York, and Witte 2006), work by the *National Action Plan for Energy Efficiency* (EPA 2006), and others. The goal of these incentives should be to assure that all utility costs for cost-effective energy efficiency should be recovered in rates, and that it is as profitable for the utility to conduct programs that reduce its sales as it is to sell more electricity. We recommend adoption of such incentive-based approaches in Texas.

New State-Level Appliance and Equipment Standards

Appliance and equipment efficiency standards are mandatory efficiency requirements set by a state or nation that products must meet to qualify for sale. Efficiency levels are set that are both technically feasible and economically justified. Typically, standards eliminate the least efficient products from the marketplace—and sometimes mid-efficiency products as well, while leaving consumers with a wide array of products to still choose from. Efficiency standards for more than 40 products are now in effect in the U.S. Often, one or more states adopt a standard on a product, and then similar standards are adopted by Congress for national application. Most recently this process played out in the federal Energy Policy Act of 2005 in which Congress adopted new efficiency standards on 16 products. From our review of Texas forecasts and discussions with ERCOT staff, it appears these new standards are not reflected in ERCOT load forecasts and thus we include savings from these standards in our policy scenario.

In addition to federally regulated products, individual states are starting to regulate a number of other products. In 2006, the Texas Energy Conservation Office commissioned ACEEE to study standards opportunities for Texas. This study found that the following products may be appropriate for efficiency standards in Texas:

1. Bottle-type water dispensers
2. Commercial hot food holding cabinets
3. Compact audio products
4. DVD players and recorders
5. Metal halide lamp fixtures
6. Portable electric spas (hot tubs)
7. Residential pool pumps
8. Single-voltage external AC to DC power supplies
9. State-regulated incandescent reflector lamps
10. Walk-in refrigerators and freezers

Eight states have already adopted standards on one or more of these products (AZ, CA, MA, NY, OR, RI, VT, and WA). More information on these products and specific standard recommendations can be found in the 2006 report for SECO (Nadel et al. 2006). This report is the source of our savings estimates for both the 2005 federal standards and new Texas state standards.

More Stringent Building Energy Codes

The Texas legislature recently directed Texas A&M to investigate new residential and commercial building codes that would reduce energy use by 15% relative to current codes. As of this writing these reports were still in preparation. However, work to date indicates that these savings targets are both feasible and cost effective. We recommend that these recommendations be adopted by the Texas Legislature. Our savings estimates for building codes assume 15% savings relative to current code, beginning in 2009, and 30% savings relative to current code beginning in 2020.

Advanced Energy-Efficient Building Program

As discussed in the earlier section on buildings, there is an economic potential to reduce energy use in new Texas homes and commercial buildings by around 50%, as new technologies make these savings realistic in the next few years. If building codes in 2009 are updated to save 15%, this leaves an additional 35% savings still to be captured. One way to do this is to offer an advanced building program that combines training and technical assistance for architects, engineers, and builders on ways to achieve these savings at modest cost, with financial incentives to help defray the extra costs, particularly on the first homes and buildings an architect or builder designs. The U.S. Department of Energy has developed many materials on how to reach these targets for new homes.[13] For commercial buildings, a good information source is the New Buildings Institute, which has a Web site on "Getting to Fifty" [percent savings].[14] Federal tax incentives can also be a key ingredient in an advanced building program. The Energy Policy Act of 2005 included $2,000/home tax credits to home builders and $1.80/square foot tax deductions for commercial building owners for each home or commercial building they build that uses 50% less energy than a new home or building designed to a national model reference code. A Texas advanced building program should be

[13] http://www.eere.energy.gov/buildings/highperformance/
[14] http://www.advancedbuildings.net/

run by an organization with extensive experience with advanced building design and construction techniques. Texas A&M may be a good choice, because it already has a respected building efficiency program. Funding for such a program could be included in electric and gas rates.

For our savings analysis, we assume 2.5% of new buildings participate in the first year, 5% in the second year, 10% in the third year, and so on until 50% are participating in the eleventh year. We assume that 80% of homes participating in the program achieve 30% energy savings above current energy code and the other 20% of homes achieve the maximum 50% savings. After 50% participation is reached in 2019, we assume that the Texas building code is upgraded to 30% above current code, achieving 100% participation at this level of efficiency. In 2020, 20% of new homes meet 50% energy savings.

Energy-Efficient State and Municipal Buildings Program

State and municipal governments and school districts have large energy bills that strain budgets, but typically have limited access to capital or expertise to make major efficiency investments. Efficiency investments can reduce energy bills, freeing up taxpayer money. In addition, if government provides leadership by demonstrating these technologies, it will provide a useful example to the private sector.

Texas has operated a major program, Texas *LoanSTAR*, to assist state and municipal facilities to undertake energy-saving investments. To date, more than 191 facilities have received funding, with energy savings averaging about 15% (Sifuentes 2007). The heart of the *LoanSTAR* program is a $95 million revolving loan fund that is used to finance efficiency improvements. In recent years this loan fund has been fully utilized and a waiting list for funds developed. We recommend that this fund be expanded so that half of all eligible facilities can receive assistance over the next 15 years. This fund would be an investment that is repaid over time, both in loan repayments and in lower ongoing energy costs for Texas state and municipal buildings and agencies (thus lowering their long-term cost to Texas taxpayers). This will require a fund of about $300 million. Our savings estimates are based on this scenario—half of eligible buildings served over 15 years with average energy savings of 15%. Costs are based on an average simple payback of 10 years.

Short-Term Public Education and Rate Incentives

As noted in the introduction to this report, Texas faces an immediate problem with respect to peak demand in the next few years. ERCOT has recently concluded that the planning reserve margin shortfall will occur in 2009 (Jones 2007), so immediate action is needed to prevent the reserve margin shortfall from turning into a real operational shortfall. To improve the balance between traditional supply-side resources and growing electricity demands before many of the other initiatives discussed in this report have fully taken effect (or new conventional power plants can be built), we recommend that Texas initiate a short-term public education effort to encourage energy saving and demand reduction actions through a wide array of media and calls by the Governor for energy conservation. Public education campaigns in California and elsewhere have been shown to produce lasting demand reductions.

We assume a Texas energy education program will produce 3% energy savings and 5% peak demand savings at half the cost of California's program. The experience of California is not unique (Global Energy Partners 2003), since other states such as New York have succeeded in achieving significant short-term reduction through public awareness efforts (Elliott, Shipley, and Brown 2003). Several elements are key to the success of these efforts:

- A consistent message and sense of urgency from a broad array of leaders including: elected officials such as the Governor, utility commissioners, and mayors of major cities; electric utilities; and media.
- Make it clear that if everyone makes modest contributions, the state as a whole will benefit.
- Provision of actionable guidance to consumers directing what specific steps they can take to contribute, such as raising their thermostats by 4 degrees when they are away from home, buying compact florescent lamps (CFLs), or tuning-up their air conditioners, and
- Report back to the public on the success of their efforts so they get a sense that they are making a difference.

If these elements are adhered to, significant reductions in peak demand can be achieved at a very modest cost. One of the observations from many Californians was that they really didn't see any lifestyle impacts from their conservation efforts. The one limitation in this policy is that these efforts cannot be effectively sustained for more than 18–24 months. However, the policy can buy important time to get the other longer-term efficiency policies in place.

Increased Demand Response Programs

Demand response is needed and beneficial in a variety of situations in ERCOT and elsewhere. It has value to moderate high energy prices or fuel shortages, and particularly as an operational reliability tool to remedy the imbalance between electricity demand and supply—in peak hours, shoulder periods, during extreme weather events and generation outages, transmission and generation contingencies, and erroneous load forecasts, or to deal with temporary air quality problems or fuel delivery shortages. The recommendations below are designed to increase the amount of demand response in ERCOT to meet the full breadth of the region's electricity challenges. Since ERCOT faces short-term power supply challenges, these recommendations focus on measures that will deliver predictable, dispatchable demand response in ways consistent with Texas's current market policies and philosophy.

The recommendations for how to expand Texas's demand response programs and capability are summarized below and explained in further detail in Appendix D.

The Texas Legislature should require that all new residential and commercial buildings constructed after mid-2008 have smart, communicating, programmable thermostats that will be used (with mandatory participation) for direct load control operated by curtailment service providers, retail electric providers, or the transmission and distribution utilities (including municipal and cooperative utilities). The PUCT should create direct load control programs to manage air conditioning and at least one other household load (such as pool pumps and hot water heaters) and commercial loads to maximize the amount of direct load control (an incentive-based, emergency-oriented demand response mechanism) available to help meet Texas's and ERCOT's reliability needs.

A core of demand response programs—particularly direct load control programs—should be administered by Texas's transmission and distribution utilities, which should receive full cost recovery and incentives for good performance. These programs should be designed for multi-year commitments, to facilitate participation by third-party curtailment providers and retail customers.

The Texas Legislature should require all Texas retail electric providers and utilities (including munis and coops) to meet a Demand Response Portfolio Requirement, achieving no less than 3% of peak load from demand response resources by 2011, 6% by 2017, and 10% by 2023. Demand response MW achieved should be reflected in tradable Demand Response Credits, so that companies can buy such credits from third-party providers or other utilities if their business model does not lend itself to offering demand response programs.

The Legislature should require ERCOT to raise the amount of LaaR from 1,150 MW as total responsive reserve requirements grow, and find ways for the other LaaR providers that are willing to reduce their loads upon call to do so when needed (so that load reduction capability does not go to waste when it is needed for price reduction or reliability protection benefits).

The Legislature should mandate that all Texas utilities (including munis and coops) and retail electric providers collect detailed data of customer energy uses and consumption, both for load research and to better understand how customers respond to dynamic electricity prices over time.

The rate of advanced interval meter deployment should be accelerated, and all customers having interval meters should be settled based upon those meter readings rather than on predetermined average group load profiles. This will encourage and enable more retail electric providers to offer time-sensitive rates and dynamic energy prices to their customers.

The PUCT should continue raising spot market price caps, and eliminate market mitigation entirely when more than 10% of ERCOT load is participating in price-responsive or incentive-based demand response programs.

ERCOT should resolve the current operational obstacles that prevent demand resources from bidding into the real-time energy market.

Texas should conduct a long-term education and marketing program to help customers understand demand response, funded through wires charges to all transmission providers. This will hasten the day when customers feel comfortable with the prospect of taking electricity under dynamic rates, so that real structural change occurs in Texas's and ERCOT's demand for electricity and its supporting physical infrastructure.

These policy recommendations are explained in further detail in Appendix D. If these policies are undertaken, we expect that Texas could significantly reduce peak demand levels at limited cost, as shown in Table 3.

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Table 3. Texas Demand Response Levels and Costs

	2013 Demand Response MW	2013 Program and Investment Costs	2023 Demand Response MW	2023 Program and Investment Costs
Residential	1,549	$ 80.4 mil	5,540	$ 266.8 mil
Commercial	954	$ 38.3 mil	6,551	$ 109.7 mil
Industrial	960	$ 40.9 mil	1,150	$ 50.4 mil
Total	3,463	$ 159.6 mil	13,241	$ 426.9 mil

CHP Generation Target

Texas has been a leader in implementing utility and environmental regulatory policies that create a favorable environment for CHP (Brown and Elliott 2003). The state's leadership has been rewarded with continued growth in the installed CHP capacity and the fraction of electricity generated by CHP, as was discussed earlier. The recent slowdown in installation of CHP capacity appears to be related to the rapid increases in recent years and future uncertainty of prices for natural gas that is used to fuel most CHP systems (see Brooks, Elswick, and Elliott 2006 for a more detailed discussion of these market conditions). This natural gas price uncertainty is further complicated in the industrial sector by the uncertainty about the long-term viability of domestic manufacturing facilities, leading many manufacturers to be unwilling to commit to long-lived assets such as CHP facilities.

While additional tweaking of regulatory policies for CHP might provide additional incremental incentive, what is needed is a commitment by the state to promote new installations that allow the state to benefit from the capabilities of CHP systems. The areas of ancillary service valuation (e.g., voltage stabilization and reactive power support) would be areas for continued efforts. We anticipate that CHP will continue to be natural gas fueled, so the significant efficiency improvements that CHP systems offer will help the state use its natural gas resources more effectively. More importantly, CHP facilities can be particularly important players in peak demand management efforts because most CHP responds to market price signals, and, because it tends to be located in urban load centers, will improve capacity and energy delivery by reducing line losses and supporting voltage in those load centers.

Because of the benefits from expanded CHP, we recommend that Texas set a target for additions to CHP capacity, much as the state has done for energy efficiency and renewable energy resources. Therefore we propose that the state establish a target of 250 MW per year of new CHP capacity for the next 15 years. This policy would reduce the state's system peak by a corresponding amount and reduce the need for grid-supplied electricity by almost 2 billion kWh each year.

Onsite Renewable Energy Policies

The broad range of renewable energy options available throughout Texas calls for a suite of policies to accelerate their market acceptance and utilization. General policy options include:

1. Supply-Side incentives—to make the renewable energy production more cost competitive (e.g. tax credits, a "buy down" incentive such as standard offer payments and rebates, low-interest financing).
2. Demand-Side Policies—examples include mandates (e.g., Renewable Portfolio Standards that may include set-asides) and "must buy" policies (e.g., standard offer contracts, feed-in laws) and building codes.
3. Enabling Policies—to prepare the market to succeed (e.g., installer training and certification, interconnection requirements, competitive wholesale markets, retail real-time pricing, net metering, zoning and insurance guidelines).

Texas wind power illustrates how the combination of effective policies can stimulate robust success. The federal Production Tax Credit (PTC—a supply-side incentive) combined with the state's exceptionally successful RPS (demand-side policy) and excellent market rules for interconnection and wholesale transactions (enabling policies) have produced a 56% annual growth rate for Texas wind power during the past 6 years. The PTC incentive has significantly lowered the price of wind power to buyers, thereby lowering or eliminating the cost of compliance with RPS requirements.[15] When designed properly, supply-side and demand-side policies can work effectively in tandem and synergistically deliver better results than a single policy by itself.

The set of recommended policies to stimulate onsite renewable generation in Texas draw on all three types of policy approaches and are summarized below and described in Appendix F. These recommendations build upon programs already in use in Texas for which onsite renewables qualify, and provide added stimulus.

[15] According to PUCT (2007), the cost of RECs for meeting the 2007 RPS is projected to be 7 cents/residential customer/month. This conservative estimate assumes that all RECs are purchased from the spot market, whereas most RECs have been acquired in conjunction with long-term wind power contracts. (Austin Energy and Xcel Energy reported some wind purchases lowered customer bills.)

Policies to Create Demand for Onsite Renewables

- Require specific levels of diversity in Texas' Renewable Portfolio Standard (RPS) by articulating specific goals by specific dates with penalties for non-compliance. Requiring 250 MW of onsite renewable capacity by 2015 will assure a foundation of activity for stimulating this market sector in Texas. This can be accomplished through modification of the existing Texas RPS as an obligation on retail electric providers, with penalties for non-compliance. (As has been observed for wind, once a market sector is "awakened," it may quickly exceed a modest RPS goal.)

- Require a minimum level of renewable energy usage for new school buildings. Schools represent a unique opportunity as an educational platform and as an institutional customer with a long-term perspective on energy costs. The General Land Office's State Power Program can help facilitate deployment of onsite renewables at schools. School districts should be allowed to aggregate their distributed loads (e.g., multiple schools) to achieve a more significant economy of scale for an onsite renewable generation facility located at one school.

Specific Policies to Lower the Cost of Onsite Renewables

1) Expand onsite renewable usage through "buy-down" incentives funded through the System Benefits Charge that will reduce the initial cost of renewable energy equipment for the consumer. Expanding funding for the Energy Efficiency Improvement Program is a straightforward means for funding onsite renewable generation, since onsite renewables already qualify for energy efficiency standard offer incentives through the EEIP. For the purposes of this report, any specific funding intended to promote onsite renewable energy needs to be IN ADDITION TO the funding intended for energy efficiency and demand response initiatives, even if all are administered through a common program. Specific features of the onsite renewables "buy-down" include:

- That it can be complementary to RPS requirements by reducing the cost of compliance of an onsite renewable set-aside (if RPS is not used to stimulate demand, relatively higher "buy downs" may be used to kick start the market)
- Allowing special incentives (higher than standard offer amounts) to provide sufficient initial stimulus for high value renewable resources (such as PV)
- Allowing school districts and governmental jurisdictions to aggregate onsite loads
- Encouraging onsite distributed wind and biomass for large electric consumers (which may require higher project award caps for these technologies)
- Ensuring that the transmission and distribution utilities administering the programs are rewarded for good performance and not financially penalized for facilitating the onsite renewable program.
- Providing total funding for onsite renewable energy programs that grow from $50 million per year to a maximum of $170 million per year (equivalent to $0.44/MWh across all sales in Texas, or up to 75 cents/residential customer /month if spread equally across all load in Texas's competitive market)

Enabling Policies:

A number of policies are needed to address market structural issues:

- Establish easy, statewide standards for uniform interconnection
- Allow single-meter net metering for small onsite renewables and encourage deployment of smart meters capable of real-time pricing and communication with the utility [16]
- Establish workforce training programs for installers, technicians, and inspectors
- Educate policymakers, energy consumers, and the general public on opportunities for onsite renewable generation
- Encourage optional offerings for renewable energy generation on new housing and other buildings

Energy Production and Peak Demand Reductions:

Energy Production and Peak Demand Reductions: Table 4 below indicates values expected to be representative of the average conditions across Texas for capacity factor (an indicator of annual energy production relative to a maximum potential of 100%) and capacity value (an indicator of the contribution of the installed capacity toward reducing peak demand, expressed as a percentage of nameplate capacity). The demand reductions stemming from onsite renewable energy generators modeled using the incentives described above are summarized for 2013 and 2023 in Table 5 below.

Table 4. Onsite Renewable Energy Capacity Factors and Capacity Values

	Capacity Factor	Capacity Value
Distributed Wind[17]	32%	20%
Biomass Generation	80%	90%
PV	16%	50%
Small Wind	25%	20%
Solar Water Heating	40%	80%

* ERCOT initially estimated dependable capacity of West Texas wind resources at 2.6% of nameplate with an expected revision upward to 8.7%, as more experience has been gained. Behind-the-meter wind should appropriately be treated as a reduction to load, which is computed by ERCOT on an *average* basis. As such, a value based on average wind production on the order of 15% to 20% is more appropriate.
** Coastal wind resources could be significantly higher, perhaps up to 50% of nameplate.

[16] For a more extensive discussion of net metering and its various permutations, see Cooper and Rose (2006).
[17] ERCOT initially estimated dependable capacity of West Texas wind resources at 2.6% of nameplate with an expected revision upward to 8.7%, as more experience has been gained. Behind the meter wind should appropriately be treated as a reduction to load, which is computed by ERCOT on an *average* basis. As such, a value based on average wind production on the order of 15% to 25% is more appropriate. Coastal wind resources in Texas may be significantly higher, perhaps up to 50% of nameplate.

The savings summarized below are additive to the existing RPS if it is assumed that the Texas RPS is not increased and that large wind development continues. Renewable incentive programs stimulate actions that would not otherwise happen at the pace described below.

Table 5. Demand and Electricity Impacts by Technology and Year

Technology	2013 Installed Capacity (MW)	2013 Demand Impact (MW)	2013 Energy Produced (GWh)	2023 Installed Capacity (MW)	2023 Demand Impact (MW)	2023 Energy Produced (GWh)
Distributed Wind	501	100	1,403	1,768	354	4,955
Biomass Generation	250	180	1,404	1,248	1,078	8,395
PV	125	64	180	2,568	1,286	3,605
Small Wind	48	10	108	1,486	297	3,255
Solar Water Heating	49	40	177	512	411	1,800
TOTAL	973	395	3,272	7,582	3,426	22,010

Investments, Costs, and Benefits of Energy Efficiency and Renewable Energy Resource Policies

Investments in energy efficiency and renewable energy resources can help meet the energy needs of the state's growing economy at a lower cost than would result from expanded investments in conventional electricity generation. As mentioned in the introduction of this section, a forthcoming analysis will quantify the projected net impact on consumer energy expenditures and gross state product, and will also explore the impact of reduced consumption on electricity prices. Combined, these effects are anticipated to lower energy bills for the state's consumers, which will spur additional spending in other sectors of the state's economy. In addition, the proposed demand response programs will lower costs for customers by reducing the cost of meeting peak demands. Since the assessment of cost and benefits of demand response programs are different than efficiency and renewable resources, they are addressed in detail in the previous section.

The policies detailed in this report will spur investments in energy efficiency and renewable energy that will translate into lower electric bills for the consumers making these investments. Because these investments also restrain the increase in future energy prices, all consumers benefit. The total cost of these programs can be viewed as having two components:

- *Efficiency and Renewable Resource Investments*—These costs represent the investment at user facilities necessary to achieve the reductions in purchased electricity. The majority of these investments, which are cost effective to the user, would be made by the user or a third party as part of a shared savings agreement. A portion of this investment could be offset by incentives provided to the consumer as part of specific programs and policies (as will be discussed shortly).

- *Program and Administrative Costs*—These costs are associated with administering these programs and policies, including education, market transformation, and technical assistance, as well as with the measurement and verification required to assure policymakers that Texas and its citizens are receiving the promised benefits from these programs.

Table 6 presents the 2013 and 2023 cumulative (non-discounted) investment and program and administrative costs for each of the policy measures recommended in this report except for the demand response programs. The cost of these combined energy efficiency and renewable energy resource policies is 4.5¢ per kWh (see Table 6), compared with a current average retail electricity price in Texas of 9.1¢ per kWh.[18]

Table 6. Cumulative Investment and Administrative Costs

	Cumulative Program and Administrative Costs from 2008 (Million $)		Cumulative Total Investment by Consumers from 2008 (Million $)	
Policy	**2013**	**2023**	**2013**	**2023**
Utility savings target	489	1,569	3,263	10,463
Improved CHP policies	156	415	1,038	2,769
Onsite renewables policy package	85	246	2,421	18,609
More stringent building codes	320	757	2,133	5,050
Advanced building program	30	315	200	2,097
Public buildings program	214	643	1,428	4,284
Appliance & equipment standards	0.3	0.8	278	741
Short-term public ed. & rate incentives	67	67	447	447
Total (Million $)	**1,362**	**4,013**	**11,208**	**44,458**

Table 7. Cost of Saved Energy

Policies	**Total Investment including Prog. & Admin. Costs (Mill.$)**	**Total 2023 Savings (Mill. kWh**	**Levelized Cost of Saved Energy ($/kWh)***
Efficiency	29,617	79,081	$0.035
Renewables	18,854	22,010	$0.080
Combined Efficiency & Renewables	48,471	101,091	$0.045

* Assumes a 15-year measure life and 4.5% discount rate

We have conservatively projected the savings from these programs based on estimated electricity prices for Texas during the study period of 2008–2023. This estimate is conservative because many of the investments made during this period will continue to yield benefits long after 2023, but these additional savings are not reflected in these estimates. These savings will be estimated with greater sophistication in a subsequent report that will look at the savings and investments using a macro-economic model that will capture both economic impacts of the investment, as well as market price effects. As a result, these

[18] Average 2005 retail electricity price across residential, commercial, and industrial sectors (EIA 2006b).

polices are likely to appear even more attractive in this macro-economic analysis. The projected cumulative customer cost savings from the combined energy efficiency and renewable energy policies are presented in Table 8 for 2013 and 2023. The $73 billion in avoided electricity costs through 2023 are almost 50% higher than the $50 billion in projected investment and administrative costs for the alternative efficiency and renewable programs.

Table 8. Cumulative Avoided Electricity Expenditures at 9.1¢/kWh

	Million $	
Policy Bundles	**2013**	**2023**
Energy Efficiency Policies	9,581	61,294
Renewable Energy Policies	821	11,531
Total	10,402	72,825

Another way to put the energy efficiency and renewable energy investments in context is to consider the fact that by making investments in energy efficiency and renewable energy resources, we are avoiding the need to make investments in conventional generation resources. As a reference, if we assume that energy efficiency and renewable energy resources meet the 101 billion kWh of consumption in 2023 that we project for these policies, an estimated $30–37 billion in coal power plant construction costs would be avoided.[19] This estimate considers only the capital of constructing new plants and excludes the operating costs (including fuel) for these plants and the need for additional transmission and distribution investments, making energy efficiency the low-cost resource.

Required Public Funding for Energy Efficiency and Renewable Energy Policies

While the energy efficiency and renewable energy measures proposed are in and of themselves cost effective from the user's perspective, past experience with energy efficiency programs suggests that to realize the achievable level of these alternative resources, incentives will need to be provided to customers to offset a portion of the investment cost. While the optimal amount of incentive should be determined through the detailed implementation of specific programs and policies, we have estimated the general level of incentives that are consistent with similar programs in other states. These estimates are presented in Table 9. When combined with the program and administrative costs, this represents the total public investment needed to achieve the electricity savings from the proposed measures.

The total cost of implementing these energy efficiency and renewable energy programs (incentives plus program and administrative costs) averages about $720 million per year. Adding expanded demand programs, total public costs average $800 million per year. These costs help leverage the much larger (fourfold higher) total investment by consumers

[19] The investment cost for new generation was estimated by applying EIA's 2005 coal utilization factor of about 6,000 MWh per name-plated MW of capacity (EIA 2006c) to estimated avoided consumption in this analysis, and applying low (B&V 2006) and high (Clemmer 2006) estimates of the costs for new super-critical pulverized coal plants.

summarized in Table 6. While these costs will be borne in most cases by Texas's electric consumers in the form of a public benefits charge, the net impact of these investments will be to lower future consumer expenditures for electricity.

Table 9. Incentives, and Program and Administrative Costs for Policies and Programs

Policy	Cumulative Incentive Costs from 2008 (Million $)		Cumulative Program and Administrative Costs from 2008 (Million $)		Total Cumulative Public Costs from 2008 (Million $)	
	2013	**2023**	**2013**	**2023**	**2013**	**2023**
Utility savings target	1,088	3,488	489	1,569	1,577	5,057
Improved CHP policies	156	415	156	415	312	831
Onsite renewables policy package	624	1,801	156	415	779	2,216
More stringent building codes	0	0	320	482	320	482
Advanced building program	40	419	30	295	70	714
Public buildings program*	126	253	214	471	341	724
Appliance & equipment standards	0	0	0	1	0	1
Short-term public ed. & rate incentives	223	223	67	67	290	290
Total (GWh)	**2,257**	**6,599**	**1,362**	**4,013**	**3,618**	**10,612**

* The incentive cost for this program reflects the cost of repayment of a 10-year, $200 million bond to capitalize the revolving loan fund.

SUMMARY AND CONCLUSIONS

Energy efficiency, demand response, and renewable energy resources can meet the increasing demand for electricity in Texas over the next 15 years. Efficiency and renewable energy resources combined with expanded demand response can avoid the reserve margin crisis that is forecast for the state, and actually reduce the overall summer peak demand over the same period. These goals can be accomplished at a lower cost than the construction of new conventional generation resources, thus enhancing the energy security and sustaining the economic growth of the state.

We suggest nine policies to build upon the foundation of energy efficiency and renewable energy policies that Texas has already laid. These policies are:

1. Expanded Utility-Sector Energy Efficiency Improvement Program
2. New State-Level Appliance and Equipment Standards
3. More Stringent Building Energy Codes
4. Advanced Energy-Efficient Building Program
5. Energy-Efficient State and Municipal Buildings Program
6. Short-Term Public Education and Rate Incentives
7. Increased Demand Response Programs
8. CHP Generation Target

9. Onsite Renewable Energy Incentives

This portfolio of policies draws upon proven policy proposals that will quickly and cost-effectively change the future direction of Texas's energy path. These combined provisions have a levelized cost of 4.5¢/kWh, considering only the benefits that occur during the 15-year study period even though many of the resource investments will continue to yield benefits long after the end of the study period. To achieve these goals, the state would need to commit about $800 million per year for the next 15 years. However, these investments would avoid even more costly investments that would need to be made in new generation, transmission, and distribution infrastructure, which in turn would increase consumer electricity costs.

Investments in energy efficiency and renewable energy resources have been shown to create more jobs in Texas than would investment in new conventional generation. Our subsequent report will explore these macro-economic benefits in greater detail. By investing in these alternative energy resources, the state also reduces risks to its economy from future energy market volatility and potential national regulation of carbon emissions that many believe are inevitable. By meeting future energy demand with these low emission resources, the state will reduce the carbon gap that it will have to close. To realize these benefits, all that is needed is leadership to choose an alternate path.

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APPENDIX A: POLICY CASE ASSESSMENT

Table A.1. Annual Electricity Savings in Policy Case Scenario

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Electricity Savings from Recommended Policies																
	(Million kWh Saved)																
1	Increase utility savings target																
	Savings from current year programs	873	1,115	1,744	2,678	2,456	2,386	2,320	2,555	3,054	2,574	2,824	2,424	2,146	2,499	2,235	2,198
	Savings from current & prior years	873	1,958	3,633	6,183	8,423	10,514	12,466	14,585	17,129	19,104	21,258	22,938	24,281	25,930	27,258	28,501
2	Appliance & equipment standards																
	New standards	319	638	957	1,106	1,256	1,405	1,555	1,704	1,853	2,003	2,152	2,302	2,451	2,540	2,629	2,718
3	More stringent building codes																
	Savings from current yr construction	-	779	796	684	713	652	716	771	635	560	593	564	1,234	903	1,068	1,068
	Savings from current & prior years	-	779	1,561	2,218	2,893	3,496	4,153	4,854	5,406	5,874	6,368	6,824	7,941	8,709	9,629	10,533
4	Advanced building program																
	Savings from current yr construction	-	25	50	87	135	165	227	293	282	284	338	357	164	120	142	142
	Savings from current & prior years	-	25	75	160	293	453	672	954	1,219	1,482	1,795	2,122	2,250	2,332	2,435	2,536
5	Improved CHP policies	-	1,923	3,846	5,769	7,691	9,614	11,537	13,460	15,383	17,306	19,229	21,152	23,074	24,997	26,920	28,843
6	On-site renewables policy package	142	524	1,025	1,649	2,402	3,272	4,268	5,409	6,709	8,205	9,911	11,819	13,939	16,310	18,976	22,010
7	Expanded state buildings program	-	397	793	1,190	1,587	1,983	2,380	2,776	3,173	3,570	3,966	4,363	4,760	5,156	5,553	5,949
8	Short-term public ed & rate incentives	-	10,921	5,461	2,730	1,365	683	341	171	85	43	21	-	-	-	-	-
	Total	**1,334**	**17,164**	**17,350**	**21,006**	**25,910**	**31,421**	**37,372**	**43,913**	**50,958**	**57,586**	**64,701**	**71,519**	**78,696**	**85,975**	**93,400**	**101,091**
	Total - Efficiency	1,192	16,640	16,325	19,357	23,508	28,149	33,104	38,504	44,249	49,381	54,790	59,700	64,758	69,665	74,424	79,081
	Total - Renewables	142	524	1,025	1,649	2,402	3,272	4,268	5,409	6,709	8,205	9,911	11,819	13,939	16,310	18,976	22,010
	Notes																
1	Analysis covers difference between 50% of growth and current policy which calls for saving 10% of growth. Assume new targets ramped in over 3 years. Assumes savings degrade at 3.5%/year (14 year average measure life, half get replaced without intervention). Costs based on a 3 cents/kWh levelized cost, 4.5% real discount rate.																
2	Savings and costs for new standards from ACEEE study for Texas State Energy Conservation Office plus supplementary analysis of savings in 2010 and 2012. In between use straight-line ramp up. Savings and costs for EPAct 2005 standards from ACEEE analysis spreadsheet.																
3	Based on 15% savings per Texas legislature request to Texas A&M. Assume takes effect Jan. 1, 2009. Savings degrade at 1.7%/year (30 year average measure life, half replaced without intervention). Costs based on $0.06/kWh levelized cost for homes saving 15% above baseline (Morgan and Zarnikau personal communication), 4.5% discount rate.																
4	Based on twenty percent of participating homes saving 35% relative to policy above per AIA and federal tax incentive goals. Other 80% of participating homes save 15% relative to policy above. Assume participation rates of 2.5% in 2009, 5% in 2010, increasing 5% per year until 2020 when new code at 30% savings above current code takes effect. In 2020, 20% percent of new homes save 50% above current code, or 20% above the new code taking effect the same																
5	Assumes that a state-level target of 250 MW of new CHP capacity is installed per year. Incremental cost (over and above cost of new boiler) is assumed to be $600/kw installed.																
6	Renewables programs generally incentivized through EE Standard Offer program but without size limits during first 5 years, then per applicable standard offers; PV is 10 year program with substantial rebates starting at $4.25/W declining over term and yielding to applicable standard offer in year 11; RE investment costs are capital only & do not reflect O&M; RPS with required diversity goals is assumed; training & market transformation programs also necessary																
7	The Texas Loan STAR program is saving an average of about 15% with an average simple payback of 8-10 years (Turner et al. 2000, Haberl et al. 2002, Verdict personal communication). CBECS 1995 finds state and local buildings account for 17.6% of total commercial floor area. We estimate 50% of buildings can be served over a 15-year period based on discussions with TAMU/LoanSTAR experts.																
8	California achieved 6.7% energy savings and 11% demand savings in 2001 at a total cost of $893 million (GEP 2003), with savings in 2002 about 1/2 -2/3 of the 2001 figure (Lutzenhiser et al. 2004, Dahlberg 2002). To be conservative, we assume a Texas program will save 3% of energy and 5% of peak in its first full year and degrade by 50% per year. We estimate costs for a TX program at half those of the CA program, based on the fact that our savings estimates are less than half those that CA achieved.																

Table A.2. Annual Peak Summer Demand Savings in Policy Case Scenario

	Summer Peak Demand Savings from Recommended Policies (MW Saved)	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
1	Increase utility savings target																
	Savings from current year programs	129	384	564	699	719	735	751	768	785	815	834	852	871	891	911	932
	Savings from current & prior years	129	508	1,055	1,717	2,376	3,027	3,672	4,311	4,945	5,587	6,225	6,860	7,491	8,120	8,747	9,372
2	Appliance & equipment standards																
	New standards	74	149	223	270	317	352	386	421	455	490	524	559	593	613	633	653
3	More stringent building codes																
	Savings from current yr construction	0	166	171	147	155	142	157	171	141	125	133	128	282	208	248	251
	Savings from current & prior years	0	166	334	476	622	754	899	1054	1177	1282	1394	1498	1754	1932	2148	2362
4	Advanced building program																
	Savings from current yr construction	0	5	11	19	29	36	50	65	62	63	76	81	38	28	33	33
	Savings from current & prior years	0	5	16	34	63	98	146	209	268	326	397	471	501	520	544	568
5	Improved CHP policies	0	238	463	677	881	1075	1258	1433	1599	1756	1906	2048	2183	2312	2434	3750
6	On-site renewables policy package	16	60	118	191	284	395	526	680	862	1079	1334	1632	1976	2379	2856	3426
7	Expanded state buildings program	0	85	170	257	344	433	523	614	704	797	890	987	1088	1188	1291	1398
8	Short-term public ed & rate incentives	0	3879	1940	970	485	242	121	61	30	15	8	0	0	0	0	0
9	Expanded demand-response programs	779	1130	1595	2148	2775	3463	4209	4955	5766	6566	7573	8650	9735	10858	12050	13241
	Total	**998**	**6,220**	**5,913**	**6,741**	**8,148**	**9,839**	**11,741**	**13,738**	**15,806**	**17,899**	**20,251**	**22,704**	**25,321**	**27,921**	**30,702**	**34,769**

Notes

1-8 The load reductions from energy efficiency and onsite renewable energy are calculated by multiplying the reductions in consumption by the ratio between the total project generation in the state and the summer peak demand.

9 DR load reduction excludes current ERCOT LaaR, counts mandatory new home and business direct load control and utility-run direct load control for growing numbers of existing homes and commercial sites. Installation costs for non-mandatory sites of $90/house, $3,000/commercial, $10,000 industrial; no ratepayer cost for code-mandated new construction controls; on-going operations costs per facility range from $10 to $30/site.

APPENDIX B: DETAILED REFERENCE CASE

Table B.1. Summer Peak Demand and Electricity Consumption Forecasts by Sector and Year

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Avg annual growth rate
Peak Summer Demand (MW)	**75,668**	**77,588**	**79,468**	**81,216**	**83,014**	**84,850**	**86,728**	**88,647**	**90,608**	**92,646**	**94,730**	**96,861**	**99,039**	**101,267**	**103,545**	**105,874**	**2.26%**
Residential	36,492	37,565	38,520	39,314	40,216	40,975	41,854	42,766	43,652	44,504	45,406	46,384	47,511	48,412	49,462	50,543	2.20%
Commercial	25,795	26,599	27,390	28,133	28,918	29,712	30,506	31,304	32,086	32,994	33,867	34,778	35,738	36,626	37,578	38,593	2.72%
Industry	13,381	13,424	13,558	13,769	13,880	14,164	14,368	14,577	14,870	15,148	15,457	15,699	15,791	16,229	16,505	16,738	1.50%
Electricity Consumption (TWh)	**358**	**364**	**370**	**377**	**383**	**389**	**394**	**401**	**408**	**415**	**422**	**428**	**433**	**440**	**445**	**451**	**1.5%**
Residential	142	145	148	150	153	155	157	160	163	165	167	170	172	174	176	179	1.6%
Commercial	111	114	117	119	122	125	127	130	133	136	139	141	144	146	149	152	2.1%
Industry	105	106	107	108	109	110	111	112	113	114	116	117	118	119	120	122	1.0%

APPENDIX C: ECONOMIC POTENTIAL ASSESSMENT APPROACH AND DETAILED TABLES: ENERGY EFFICIENCY

C.1 Residential Efficiency

To estimate the economic potential for energy efficiency in residential buildings in Texas, we relied on several sources, including the Public Utility Commission of Texas's (PUCT) *Deemed Savings, Installation and Efficiency Standards*, prepared by Frontier Associates in Austin, Texas (Frontier Associates 2006), an analysis on the potential for efficiency in the Southwest by the Southwest Energy Efficiency Project (SWEEP 2002), New York State Energy and Research Development Authority's 2003 electricity efficiency potential analysis (NYSERDA 2003), the Energy Information Administration's Residential Energy Consumption Survey (EIA 2001) and the California Energy Commission's Database for Energy Efficient Resources (CEC 2001). We did not collect any primary data on technology performance.

We analyzed thirty-six efficiency measures for existing residential buildings, which are grouped by end-use (see Table C.1). For each measure, we estimated electricity savings (kWh) and costs per home upon replacement of the product or installation of the measure. Where available, we used PUCT's Deemed Savings (kWh savings/home) for efficiency measures. To estimate total economic savings potential, we multiplied savings per home by the estimated number of homes in the state that could cost-effectively take advantage of the efficiency measure over a 15-year time period (see Equation 1). We adjusted replacement measures with lifetimes more than 15 years to only account for the percent turning over in 15 years. Note that the multiplier, *% turning over in 15 years,* is only applicable to products being replaced upon burnout and not retrofit measures such as installation and duct sealing and testing. These retrofit measures therefore have 100% of measures "turning over". We also adjusted HVAC equipment savings to account for reduced heating and cooling loads resulting from several of the installations of several measures: insulation, windows, infiltration, duct sealing, and cool roofs. Similarly, water heating equipment savings were adjusted to account for reduced water heating loads from the use of more efficient clothes washers, low-flow shower heads, water heater pipe insulation, and faucet aerators.

Equation 1. *Potential electricity savings (GWh) in 2023 = (per-measure annual electricity savings (kWh) per household) x (millions of Texas households in 2008) x (percent households applicable) x (interaction factor from reduced HVAC or water heating loads) x (% measures turning over in 15 years)*.

For new construction homes, we looked at two levels of efficiency: 15% better than current energy code and 50% better than code. Savings were estimated based on the number of new homes built between 2008 and 2023 (Economy.com 2007) and the percent of new homes applicable (see Equation 2.)

Equation 2. *Potential electricity savings (GWh) in 2023 = (per-home annual electricity savings (kWh) per household) x (millions of Texas households constructed 2008-2023) x (percent households applicable)*

Estimated levelized costs for each efficiency measure, which assume a discount rate of 4.5%, are shown in Table C.1. Measures with a total costs of saved energy ($/kWh saved) less than current average electricity prices in Texas, 10.84 cents/kWh in 2005 (EIA 2006b), were considered cost-effective. The average levelized is actually much lower, less than 6 cents per kWh saved for all efficiency measures analyzed and an average of about 5 cents for all measures deemed cost-effective. The overwhelming majority (95%) of savings potential, or 55,679 GWh in 2023, has a levelized cost less than $0.08/kWh saved.

We estimate a total potential for cost-effective electricity savings in Texas of 57,720 GWh, or 32% of projected electricity consumption in 2023. Although the potential for cost-effective electricity savings is large, please note that only a portion of these savings would be realistically achievable given market and policy limitations. See Appendix A for the total achievable electricity savings in Texas.

Table C.1. Residential Efficiency Measure Savings and Costs

Residential - Existing Homes	Avg kWh Saved per Home	Measure Cost	Measure Life (years)	% of Homes Applicable	Interaction Adjustment	% Turning Over in 15 Years	GWh Savings Available	Cost per kWh Saved
Space Heating and Cooling								
Duct efficiency improvement							11,858	
Duct efficiency improvement Gas Heat	1319	$ 323	20	28%	NA	100%	3200	$ 0.02
Duct efficiency improvement Electric Heat	4530	$ 509	20	20%	NA	100%	7691	$ 0.01
Duct efficiency improvement Heat Pump	2656	$ 509	20	4%	NA	100%	966	$ 0.01
Air infiltration reduction							1,603	
Air infiltration reduction Gas Heat	352	$ 304	15	10%	NA	100%	320	$ 0.08
Air infiltration reduction Electric Heat	881	$ 476	15	15%	NA	100%	1122	$ 0.05
Air infiltration reduction Heat Pump	590	$ 476	15	3%	NA	100%	161	$ 0.08
Ceiling insulation							1767	
Ceiling insulation Gas Heat	432	$ 627	20	0%	NA	100%	0	$ 0.11
Ceiling insulation Electric Heat	2427	$ 987	20	8%	NA	100%	1595	$ 0.03
Ceiling insulation Heat Pump	1209	$ 987	20	1.6%	NA	100%	170	$ 0.06
Wall insulation							9,726	
Wall insulation Gas Heat	446	$ 411	20	16%	NA	100%	605	$ 0.07
Wall insulation Electric Heat	8707	$ 647	20	11%	NA	100%	8262	$ 0.01
Wall insulation Heat Pump	4222	$ 647	20	2%	NA	100%	859	$ 0.01
Floor insulation							2,304	
Floor insulation Gas Heat	55	$ 659	20	0%	NA	100%	0	$ 1.38
Floor insulation Electric Heat	3330	$ 1,036	20	7%	NA	100%	2107	$ 0.02
Floor insulation Heat Pump	1455	$ 1,036	20	2%	NA	100%	197	$ 0.05
Energy Star windows							3926	
Energy Star windows Non-electric heating	692	$ 150	30	25.0%	NA	50%	1503	$ 0.01
Energy Star windows Electric Resistance Heating	1364	$ 236	30	17.5%	NA	50%	2074	$ 0.01
Energy Star windows Heat Pump	1072	$ 236	30	3.7%	NA	50%	349	$ 0.01
Solar Screens							2047	
Solar Screens Gas Heat	1051	$ 326	20	15.0%	NA	100%	1369	$ 0.02
Solar Screens Electric Heat	593	$ 513	20	10.5%	NA	100%	540	$ 0.07
Solar Screens Heat Pump	704	$ 513	20	2.2%	NA	100%	137	$ 0.06
Cool roof	237	$123	20	70%	NA	75%	1084	$ 0.04
Efficient furnace fan	322	$ 196	18	73%	44%	83%	905	$ 0.05
Central A/C replacement 14 SEER	408	$ 155	18.4	68%	44%	82%	1070	$ 0.03
Residential - Existing Homes	Avg kWh Saved per	Measure Cost	Measure Life	% of Homes	Interaction Adjustment	% Turning	GWh Savings	Cost per kWh Saved

	Home		(years)	Applica ble		Over in 15 Years	Available	
Central A/C replacement 15 SEER	228	$ 244	18.4	61%	44%	82%	534	$ 0.09
Central heat pump replacement							197	
Cooling savings (14 SEER)	408		18.4	7.4%	44%	82%	95	NA
Heating savings (8.2 HSPF)	255	$ 155	18.4	7.4%	44%	82%	59	$ 0.05
Cooling savings (15 SEER)	228		18.4	6.6%	44%	82%	47	NA
Heating savings (8.5 HSPF)	91	$ 244	18.4	0%	44%	82%	0	$ 0.22
Central A/C and HP tuneup	563	$ 156.00	10	40%	44%	100%	875	$ 0.04
Efficient room A/C	159	$ 30.00	13	5%	44%	100%	29	$ 0.02
Ground source heat pump (GSHP) - w/ desuperheaters (17 EER and above)	1437	$ 3,300	15	0%	44%	100%	0	$ 0.21
				Total HVAC savings Available (GWh)			**38,168**	
				% HVAC End-Use Savings Available in 2023			**59%**	
Water Heating								
Efficient water heater replacements - elec	210	70	14	17%	84%	100%	305	$ 0.03
Heat pump water heater	1505	$ 1,450	14.5	17%	84%	100%	1882	$ 0.09
Low flow showerheads	186	$ 9.23	10	30%	NA	100%	485	$ 0.01
Water heater jacket	100	$ 14.00	10	50%	NA	100%	435	$ 0.02
Water heater pipe insulation	40	$ 8.10	10	39%	NA	100%	136	$ 0.03
Faucet aerators	48	$ 4.82	10	50%	NA	100%	209	$ 0.01
Ground source heat pump w/ desuperheater (17 EER and above) - DHW savings	2447	$ 3,189	15	0%	84%	100%	0	$ 0.12
				Water Heating Savings Potential (GWh)			**3,478**	
				% Water Heating End-Use Savings Potential in 2023			**28%**	
Appliances and Lighting								
Energy Star refrigerator (current)	85	$ 24.00	19	90%	NA	79%	665	$ 0.02
Refrigerator saving 20%	29	$ 40.00	19	0%	NA	79%	0	$ 0.11
Compact fluorescent lamps	416	$ 12.00	7	95%	NA	100%	3,435	$ 0.00
Water bed insulation (mattress cover)	600	$ 35.00	10	2.6%	NA	100%	136	$ 0.01
Energy Star clothes washer (current)	151	$ 108	14	25%	NA	100%	332	$ 0.07
Energy Star clothes washer (2007)	116	$ 108	14	30%	NA	100%	300	$ 0.09
Energy Star dishwasher (current)	78	$ 20	13	61%	NA	100%	409	$ 0.03
with elec water heating	142	$ 20	13	24%	NA	100%	294	$ 0.01
without elec water heating	37	$ 2	13	36%	NA	100%	115	$ 0.01
Energy Star dishwasher (2007)	40	$ 20	13	61%	NA	100%	212	$ 0.05
Energy Star dehumidifier	85	$ -	12	2.6%		100%	19	$ -
Reduced standby power (TV, DVD, etc.)	265	$ 30	7	22%	NA	100%	507	$ 0.02
Efficient ceiling fan	416	$ 98	15	83%	NA	100%	3009	$ 0.02
2-speed pool pumps	1040	$ 580	10	4%	NA	100%	352	$ 0.07
Outdoor lighting controls	194	$ 75	10	50%	NA	100%	842	$ 0.05
				Total Appliances Savings Potential (GWh)			**10,219**	
				% Appliances End-Use Savings Available in 2023			**13%**	
Residential - New Homes								
New home 15% above code	1874	$ 1500	20	50%	NA	NA	2888	$ 0.062
New home (50% savings above code)	4811	$ 4773	20	20%	NA	NA	2967	$ 0.076

	% Savings of 2023 Projected Electric Sales	GWh
TOTAL EXISTING HOMES POTENTIAL	29%	**51,507**
TOTAL NEW CONSTRUCTION POTENTIAL	3%	**5,855**
TOTAL RESIDENTIAL ECONOMIC POTENTIAL	**32%**	**57,720**

Assumptions: 1850 sq. ft. average existing home; window area equal to 10.2% of floor area, 14% of wall area (Frontier Associates 2006). The average existing home has 1.5 stories (EIA 2001). Reference case: total residential electricity consumption in 2023 is 178,588 GWh. Space heating and cooling account for 37% of electricity use; water heating accounts for 7%; and appliances and lighting for 56% (EIA 2001).

Table C.2. References for Residential Buildings Measure Savings and Cost Estimates

Measure	Deemed Savings Available?	kWh Saved per Home	Measure Cost	Measure Life	% of Homes Applicable	Notes
Duct efficiency improvement	yes	Frontier Associates 2006; ACEEE calc.	SWEEP 2002	SWEEP 2002	ACEEE estimate	Includes duct sealing, testing and insulation. Savings assume avg. duct loss factor of 30%. Estimate 2/3rds of homes with Central AC are applicable.
Air infiltration reduction	yes	Frontier Associates 2006	CEC 2001	SWEEP 2002	EIA 2001; ACEEE estimate	Savings assume single-story home with normal shielding, 30% air leakage reduction. Estimate 50% of homes with Central AC are applicable. Gas savings applicable only to homes in Valley and South regions of Texas.
Ceiling insulation	yes	Frontier Associates 2006	CEC 2001	NYSERDA 2003	EIA 2001	R-30 insulation level (assumes baseline of R-5 to R-8). Applicable to homes with elec. AC.
Wall insulation	yes	Frontier Associates 2006	CEC 2001	NYSERDA 2003	EIA 2001	Savings assume increase of R-0 to R-13; baseline is home with no existing wall insulation in the 4" cavity.
Floor insulation	yes	Frontier Associates 2006	CEC 2001	NYSERDA 2003	EIA 2001	R-19 for site-built homes and R-15 for manufactured homes. Homes with electric AC.
Energy Star windows	yes	Frontier Associates 2006	Arasteh 2007	SWEEP 2002	Arasteh 2007	U-factor and SHGC less than or equal to 0.40 (baseline is double-glazed, clear window with an aluminum frame and sash). Per square-foot savings assume window area is 10.2% of conditioned area.
Solar screens	yes	Frontier Associates 2006	SWEEP 2002	SWEEP 2002	Frontier Associates 2006	Savings assume windows facing east or west and solar heat gain reduction at least 65%. Per square-foot savings assume window area is 10.2% of conditioned area.
Cool roof	no	Akbari & Konopacki 2005	ACEEE 2004	SWEEP 2002	EIA 2001	ABS = 0.7 to 0.3. Savings and % homes applicable assume homes in urban areas per LBL 2005.
Efficient furnace fan	no	Nadel et al. 2006	Nadel et al. 2006	ACEEE 2006	EIA 2001	Savings based on use of variable speed (ECM type) fans during cooling and heating seasons. Costs from DOE Technical Support Document.
Central A/C replacement - 14 SEER	yes	Frontier Associates 2006	ECW 1997	SWEEP 2002	EIA 2001; ACEEE estimate	Baseline is 13 SEER. Assume 3 Ton system. Assume 5% already at this level.
Central A/C replacement - 15 SEER	yes	Frontier Associates 2006	CEC 2001	SWEEP 2002	EIA 2001	Baseline is 13 SEER. Assume 3 Ton system.
Central heat pump replacement - 8.5 HSPF	yes	Frontier Associates 2006	ECW 1997	SWEEP 2002	EIA 2001	Baseline is 13 SEER and HSPF 7.7. Assume 3.0 Ton system.
Central heat pump replacement - 8.8 HSPF	yes	Frontier Associates 2006	CEC 2001	SWEEP 2002	EIA 2001	
Central A/C and HP tuneup	no	SWEEP 2002	SWEEP 2002	SWEEP 2002	CPUC 2006	Assumes 13% cooling savings per SWEEP 2002.
Efficient room A/C	no	Frontier Associates 2006	ACEEE 2006	ACEEE 2006	EIA 2001	Assumes 10,000 Btu/h AC. Baseline is NAECA standard.
Ground source heat pumps	yes	Frontier Associates 2006	H. Sachs pers. communication	NYSERDA 2003	NA: not cost effective	Based on replacement of an existing 13.0 SEER air source heat pump with minimum 8.0 HSPF. Heating and cooling savings only (no hot water savings from desuperheater). Assume 3 Ton system.
Efficient water heater replacements	yes	Frontier Associates 2006	Consumer Reports 2005	NYSERDA 2003	EIA 2001	Baseline is DOE standard. Assume 50 gallons and qualifying EF of 0.92. Effective in homes with 3 or more people
Heat pump water heater	no	NYSERDA 2003	NYSERDA 2003	NYSERDA 2003	EIA 2001	Assume that homes applicable are those with electric water heaters and have 3 or more people.

Low flow showerheads	yes	Frontier Associates 2006	CEC 2001	NYSERDA 2003	ACEEE estimate	Baseline is average flow rate of 2.5 gpm. Replace with maximum flow rate of 2.0 gpm.
Water heater jacket	yes	Frontier Associates 2006	CEC 2001	NYSERDA 2003	ACEEE estimate	Baseline is post-1991 storage type electric resistance water heater.
Water heater pipe insulation	yes	Frontier Associates 2006	CEC 2001	NYSERDA 2003	EIA 2001	Assume minimum insulation thickness is 3/4" installed in home with electric water heater.
Faucet aerators	yes	Frontier Associates 2006	CEC 2001	NYSERDA 2003	ACEEE estimate	Baseline is average flow rate of 2.5 gpm. Replace with maximum flow rate of 1.5 gpm, installed in home with electric DHW.
Energy Star refrigerator (current)	yes	PG&E 2006	PG&E 2006	PG&E 2006	EIA 2001	Baseline is 2001 DOE standard. Assumes 64% of products are top-mount and 36% are side-mount.
Refrigerator saving 20%	no	PG&E 2006	PG&E 2006	PG&E 2006	EIA 2001	Savings are incremental to Energy Star refrigerator.
Compact fluorescent lamps	yes	Frontier Associates 2006	ACEEE 2006	NYSERDA 2003	EIA 2001	Baseline is incandescent lamps. Assume 6 lamps replaced per home per SWEEP 2002. Savings based on 4-hr usage per day.
Water bed insulation and timer	no	NYSERDA 2003	NYSERDA 2003	NYSERDA 2003	EIA 2001	50% savings with mattress cover per NYSERDA 2003.
Energy Star clothes washer (2004)	yes	Frontier Associates 2006	ACEEE 2006	ACEEE 2006	EIA 2001	1.42 MEF. Savings from clothes washers are based on a weighted average of homes with electric water heaters and gas water heaters.
Energy Star clothes washer (2007)	no	ACEEE calc.	ACEEE 2006	ACEEE 2006	EIA 2001	1.72 MEF. Savings are incremental to 2004 Energy Star specification.
Energy Star dishwasher (2004)	yes	Frontier Associates 2006	ACEEE 2006	ACEEE 2006	EIA 2001	0.58 EF. Savings from dishwashers are based on a weighted average of homes with electric water heaters and gas water heaters.
Energy Star dishwasher (2007)	no	ACEEE calc.	ACEEE 2006	ACEEE 2006	EIA 2001	0.65 EF Savings are incremental to 2004 Energy Star specification.
Energy Star dehumidifier	no	EPA 2004	EPA 2004	EPA 2004	EIA 2001	Savings from energy savings calculator on Energy Star website.
Reduced standby power (TV, DVD)	no	ACEEE 2004	ACEEE 2004	ACEEE 2004	ACEEE 2004	Savings based on replacement of 15 household products, which account for about 50 Watts, with products meeting 1.0 Watt threshold for standby power.
Efficient ceiling fan	no	NYSERDA 2003	NYSERDA 2003	NYSERDA 2003	EIA 2001	Savings based on upgrade to Energy Star and assume average of 2.4 ceiling fans per home (EIA 2001).
2-speed pool pumps	no	Nadel et al. 2006	Nadel et al. 2006	Nadel et al. 2006	EIA 2001	Based on 40% savings.
Outdoor lighting controls	no	NYSERDA 2003	NYSERDA 2003	NYSERDA 2003	ACEEE estimate	Savings based on high performance outdoor light fixture that operate at least 2.5 hours per day.
New home 15% savings above code	yes	Morgan 2007; ACEEE calc.	Morgan 2007; Zarnikau 2006.	Haberl et al. 2005	Morgan 2007	New Energy Star home saves 15%. Baseline consumption is 12,491 kWh per year for avg. 2200 sq. ft. home (Morgan 2007).
New home 50% savings above code	no	Malhotra and Haberl 2005; ACEEE calc.	Haberl et al. 2005	Haberl et al. 2005	ACEEE estimate	Baseline consumption is 11,933 kWh per year (Malhotra and Haberl 2005). Savings and costs are incremental to homes 15% above code and adjusted to account for electricity only (costs for measures to reduce gas consumption not included) and are incremental to homes 15% above code.

C.2. Commercial Efficiency

We used four major sources for the commercial buildings analysis: SWEEP's 2002 efficiency potential analysis (SWEEP 2002), NYSERDA's 2003 efficiency potential analysis (NYSERDA 2003), the Energy Information Administration's Commercial Buildings Energy Consumption Survey (EIA 2003) and the California Energy Commission's Database for Energy Efficient Resources (CEC 2001).

To estimate the economic potential for efficiency savings, we estimated electricity savings from efficiency measures on either a per-unit or a percent savings basis (see Equations 2 and 3). We analyzed 27 efficiency measures for existing commercial buildings, which are grouped by end-use (see Table C.3). For each measure, we estimated electricity savings (kWh) and costs per building upon replacement of the product or installation of the measure. Note that the multiplier, *% turning over in 15 years,* is only applicable to products being replaced upon burnout and not retrofit measures such as installation and duct sealing and testing. Measures were considered to be cost-effective if the cost per kWh saved was less than current retail electricity prices in the commercial sector, or $0.0885/kWh in 2005 (EIA 2006b).

Equation 3. *Electricity savings (GWh) potential in 2023 = (per-measure annual electricity (kWh) savings) x (Texas product stock in millions) x (% applicable) x (% turning over in 15 years) x (interaction factor from reduced HVAC and water heating loads)*

OR

Equation 4. *Electricity savings (GWh) potential in 2023 = (per-measure electricity savings (kWh per square foot)) x (commercial floor space in Texas in millions of square feet) x (interaction factor from reduced HVAC or water heating loads)* x *(% applicable) x (% turning over in 15 years)*

We estimate an economic potential in existing commercial buildings for 45,629 GWh of electricity savings from efficiency, or 30% of projected electricity consumption in commercial buildings. New buildings can save an additional 10%, or 14,377 GWh. The total potential is 60,006 GWh, or 40% of electricity consumption in 2023. See Table C.3 for a breakdown of savings and costs by end-use and measure. Although the potential for cost-effective electricity savings is large, please note that only a portion of these savings would be realistically achievable given market and policy limitations. See Appendix A for the total achievable electricity savings in Texas.

Table C.3 Economic Potential for Efficiency in Commercial Buildings: Savings and Costs

Commercial - Existing	kWh Saved per unit	Texas Stock	Base kWh per sf	% Savings	kWh Saved per sf	Measure Cost	Cost Units	Measure Life (years)	Cost per kWh Saved	% Applicable	Interaction Factor	% Turning Over in 15 Years	GWh Savings Available
Lighting													-
Fluorescent lighting improvements	122		6.00	39%	2.31	$ 4	fixture	13	$0.003	56%	100%	100%	7,750
HID lighting improvements	447		6.00	26%	1.57	$ 60	fixture	13.5	$0.013	12%	100%	100%	1,124
Replace incandescent lamps	180		6.00	69%	4.16	$ (22)	socket	2.3	negative	22%	100%	100%	5,575
Occupancy sensor for lighting	361		6.00	19%	1.13	$ 48		10	$0.017	33%	100%	100%	2,221
Daylight dimming system	143		6.00	35%	2.10	$ 68		20	$0.037	35%	100%	100%	4,397
LED exit signs	263	1,172,511				$ (16)	per unit	10	-$0.008	50%	100%	100%	154
Outdoor lighting -- improved efficiency	261	4,627,361				60	fixture	13.5	$0.023	90%	100%	100%	1,089
Outdoor lighting -- controls	174	4,627,361				$ 128	fixture	13.5	$0.074	30%	100%	100%	242
												Total Lighting Savings Potential (GWh)	**22,552**
												% Lighting End-Use Savings Potential	**35%**
HVAC													-
High-efficiency unitary AC	7554	2,853,540				$ 1,924	11.25 Ton	15	$0.024	40%	95%	100%	8,209
High-efficiency unitary HP	9112	42,417				$ 1,924	11.25 Ton	15	$0.020	40%	95%	100%	147
High-efficiency chiller systems package	169,680		20.2	14%	2.83	$ 21,326	150 Ton system	20	$0.010	50%	95%	75%	6,040
Duct testing and sealing	24,828		17.4	6%	1.00	$ 1,688	AC tons	20	$0.005	25%	95%	NA	747
Cool roof	10913		28.3	2.6%	0.73	$ 7,500	roof area	20	$0.053	80%	100%	NA	580
Roof insulation	6000		28.3	1.4%	0.40	$ 5,250	roof area	20	$0.067	50%	100%	NA	399
Low-e replacement windows	1,489		28.3	2.6%	0.73	$ 1,489	window area	25	$0.067	75%	100%	60%	296
												Total HVAC Savings Potential (GWh)	**16,418**
												% HVAC End-Use Savings Potential	**39%**
Water Heating													-
Efficient electric water heater	250		0.42	5%	0.021	$ 78.47		15	$ 0.029	40%	98.5%	100%	50
Heat pump water heater	14155		0.42	43%	0.182	$ 4,067		14	$ 0.028	40%	98.5%	100%	430
												Total Water Heating Savings Potential (GWh)	**480**
												% Water Heating End-Use Savings Available	**24%**
Refrigeration													-
Efficient walk-in coolers & freezers	8220	87,794				$ 957	average unit	12	$ 0.01	50%	100%	100%	361
Efficient reach-in coolers & freezers	1838	223,656				$ 341	average unit	9	$ 0.03	90%	100%	100%	370
Efficient ice-makers	958	146,533				$ 200	average unit	10	$ 0.03	80%	100%	100%	112
Efficient built-up refrigeration system	392,880	2,993				$ 39,158	average unit	10	$ 0.01	30%	100%	100%	353
Efficient vending machines	968	409,042				$ 148	average unit	10	$ 0.019	50%	100%	100%	198
Vending miser	1724	409,042				$ 167.41	average unit	10	$ 0.012	50%	100%	100%	353
												Total Savings Potential (GWh)	**1746**
												% Refrigeration End-Use Savings Potential	**14%**
Appliances and Misc.													-
Efficient office equipment	50,768		20.2	13%	2.63	$ 387	avg. school/office	5	$ 0.00	23%	100%	100%	3,535
Efficient distribution transformers	1,951	173,908				$ 327.77	unit	30	$ 0.01	90%	100%	50%	153
Efficient clothes washers	302	168,282				$ 208	unit	10	$ 0.087	60%	100%	100%	30
												Total Appliances and Miscellaneous Savings Potential (GWh)	**3718**
												% Appliances End-Use Savings Potential	**12%**
												TOTAL EXISTING COMMERCIAL BUILDINGS POTENTIAL (GWh)	**44,914**
												% 2023 Annual Generation	**30%**
Commercial - New Construction													
Efficient new building (15% savings)	222,000	2,708	14.8	15.0%	2.22	$ 35,000	100k sq. ft. bldg	15	$ 0.015	80%	NA	100%	5,848
Tax credit eligible building (50% svgs)	296,000	2,708	14.8	50%	5.18	$ 85,000	100k sq.ft. bldg	15	$ 0.027	50%	NA	100%	8,529
												TOTAL NEW COMMERCIAL BUILDINGS POTENTIAL (GWh)	**14,377**
												% 2023 Annual Generation	**9.5%**
												TOTAL COMMERCIAL BUILDINGS POTENTIAL (GWh)	**59,292**
												% 2023 Annual Generation	**39%**

Notes: Baseline electricity consumption by end-use breakdown is taken from CBECS 1995 for the West South Central census division (EIA 1995), the last year that CBECS collected this data. From this, we assume the following percentage end-use breakdown for electricity consumption in the commercial sector: Lighting - 43%; HVAC: 28% (Ventilation: 7%; Cooling: 19%; Heating: 2%); Refrigeration: 8%; Water Heating: 1.3%; Miscellaneous: 20%. Most Texas stock estimates are prorated by population from national estimates; we estimate annual growth rates for products to estimate stock values in 2008.

Table C.4. References for Commercial Building Measure Costs and Savings

Commercial	kWh Saved per unit	Texas Stock	Base kWh per sf	% Savings	kWh Saved per sf	Measure Cost	Measure Life (years)	% Applicable	Notes
Fluorescent lighting improvements	ACEEE estimate	N/A	Navigant 2002	ACEEE calc.	ACEEE calc.	ACEEE estimate	Navigant 2002; DOE TSD	Navigant 2002	Basecase assumes 50% are 3 lamp fixtures with 34W lamps and magnetic ballasts and other 50% are 2 lamp fixtures with standard T8 lamps and electronic ballasts. Savings case is super T8 lamps with efficient low BF ballasts. Costs are $2 extra for ballast, $1 extra for each of 2 lamps.
HID lighting improvements	Navigant 2002	N/A	Navigant 2002	PG&E 2004	ACEEE calc.	PG&E 2004	PG&E 2004	Nagiant 2002	Data from PG&E case study on Metal Halide Lamps & Fixtures (PG&E 2004)
Replace incandescent lamps	Navigant 2002	N/A	Navigant 2002	ACEEE calc.	ACEEE calc.	ACEEE estimate	ACEEE calc.	Navigant 2002; ACEEE estimate	Savings assume and average 75 W incandescent lamp replaced with 23W CFL, 9.5 hrs/day. Costs are $10 CFL incremental cost, save $8 labor each from replacing 4 incandescent lamps (2000 hr life). Estimate 70% of sockets are applicable.
Occupancy sensor for lighting	NYSERDA 2003	N/A	Navigant 2002	ACEEE estimate	ACEEE calc.	NYSERDA 2003	NYSERDA 2003	ACEEE 2004	Savings assume 30% energy reduction in individual offices and rooms and 7.5% reduction in open spaces.
Daylight dimming system	NYSERDA 2003	N/A	Navigant 2002	PIER 2003	ACEEE calc.	NYSERDA 2003	NYSERDA 2003	PIER 2003	Savings apply for lamps on perimeter of buildings (35% applicable).
LED exit signs	NYSERDA 2003	E-Source 1994	N/A	N/A	N/A	NYSERDA 2003	NYSERDA 2003	ACEEE estimate	Savings and cost estimates from NYSERDA analysis.
Outdoor lighting -- improved efficiency	PG&E 2004 Navigant 2002	Navigant 2002	N/A	N/A	N/A	CEC 2001	PG&E 2004	ACEEE estimate	Data from PG&E case study on Metal Halide Lamps & Fixtures and Navigant 2002. Estimate that 10% are already in use.
Outdoor lighting -- controls	ACEEE estimate	Navigant 2002	N/A	N/A	N/A	CEC 2001	PG&E 2004	ACEEE estimate	Estimate 20% savings from outdoor lighting controls.
High-efficiency unitary AC	Frontier Associates 2006	ADL 1999	N/A	N/A	N/A	CEC 2001	LBNL 2003	ACEEE estimate	Savings assume an 11.25 Ton, 11 EER unit (baseline 8.9 EER). Costs are estimate for 11.25 Ton, 10.9 EER AC (baseline 8.9 EER).
High-efficiency unitary HP	Frontier Associates 2006	ADL 1999	N/A	N/A	N/A	CEC 2001	LBNL 2003	ACEEE estimate	Savings assume an 11.25 ton, 3.2 COP unit (baseline 3.0 COP).
High-efficiency chiller systems package	SWEEP 2002	N/A	SWEEP 2002	SWEEP 2002	SWEEP 2002	SWEEP 2002	SWEEP 2002	ACEEE estimate	Savings per unit assume 60,000 sq.ft. office building. 6.3 COP (0.56 kW/ton) chiller, higher fan efficiency (55% - 70% improvement), and variable frequency drive (VFD). Baseline is whole building energy intensity for prototypical 60,000 sq. ft. office and % savings are whole building electricity savings.
Duct testing and sealing	SWEEP 2002	N/A	SWEEP 2002	SWEEP 2002	SWEEP 2002	SWEEP 2002	SWEEP 2002	ACEEE estimate	Baseline is assumed air loss of 29% fan flow; savings are based on sealing supply and return ducts to max. leakage of 15% of system flow at 25 Pascal pressure. Savings per unit and base kWh/sq. ft. for an average retail or education building: 21, 721 sq. ft.. Costs assume $150 per ton. Applicable to small buildings.
Cool roof	SWEEP 2002	N/A	SWEEP 2002	SWEEP 2002	SWEEP 2002	SWEEP 2002	SWEEP 2002	ACEEE estimate	ABS = 0.7 to 0.3. Per unit savings assume a typical 90,000 sq. ft. office/retail building. Percent savings apply to whole building. Base kWh per square foot is average electricity intensity of four major building types (SWEEP 2002). Percent savings apply to whole building. Costs are $0.50/ sq. ft.

Roof insulation	SWEEP 2002	N/A	SWEEP 2002	SWEEP 2002	SWEEP 2002	SWEEP 2002	SWEEP 2002	ACEEE estimate	R-30 roof (add R-19). Per unit savings assume a typical 90,000 sq. ft. office/retail building. Base kWh per square foot is average electricity intensity of four major building types (SWEEP 2002). Percent savings apply to whole building. Costs are $0.35/ sq. ft.
Low-e replacement windows	SWEEP 2002	N/A	SWEEP 2002	SWEEP 2002	SWEEP 2002	SWEEP 2002	SWEEP 2002	ACEEE estimate	SC = 0.3, U=0.356. Base kWh per square foot is average electricity intensity of four major building types (SWEEP 2002). Percent savings apply to whole building. Per unit savings assume 13,550 sq. ft. commercial building and that window area equals 15% of floor area (Haberl et al. 2005)
Efficient electric water heater	NYSERDA 2003	ADL 1993	EIA 2003	NYSERDA 2003	ACEEE calc.	NYSERDA 2003	NYSERDA 2003	ACEEE estimate	Savings assume a high-efficiency tank type water heater.
Heat pump water heater	NYSERDA 2003	N/A	EIA 2003	NYSERDA 2003	ACEEE calc.	NYSERDA 2003	NYSERDA 2003	ACEEE estimate	Savings and cost estimates from NYSERDA analysis.
Efficient walk-in coolers & freezers	Nadel et al. 2006	ADL 1993	N/A	N/A	N/A	Nadel et al. 2006	Nadel et al. 2006	ACEEE estimate	Savings and cost estimates from ACEEE analysis (Nadel et al. 2006) based on PG&E case study (2005).
Efficient reach-in coolers & freezers	PG&E 2005	PG&E 2005	N/A	N/A	N/A	PG&E 2005	PG&E 2005	ACEEE estimate	Savings estimate is a weighted average of different types of reach-ins (PG&E 2005)
Efficient ice-makers	PG&E 2005	PG&E 2005	N/A	N/A	N/A	PG&E 2005	PG&E 2005	ACEEE estimate	Savings and stock estimate from PG&E case study (PG&E 2005).
Efficient built-up refrigeration system	ADL 1996	ADL 1996	N/A	N/A	N/A	NYSERDA 2003	NYSERDA 2003	NYSERDA 2003	Per-unit savings assume an average new 45,000 sq. ft. supermarket
Efficient vending machines	NYSERDA 2003	ADL 1993	N/A	N/A	N/A	NYSERDA 2003	NYSERDA 2003	NYSERDA 2003	Savings and cost estimates from NYSERDA analysis.
Vending miser	NYSERDA 2003	ADL 1993	N/A	N/A	N/A	NYSERDA 2003	NYSERDA 2003	ACEEE estimate	Savings and cost estimates from NYSERDA analysis.
Efficient office equipment	SWEEP 2002	N/A	SWEEP 2002	SWEEP 2002	SWEEP 2002	SWEEP 2003	SWEEP 2002	SWEEP 2002	Per-unit savings are for a 19,333 sq.ft. average office or education building. Baseline is whole building energy intensity for prototypical medium office building and savings are whole building electricity savings.
Efficient distribution transformers	Nadel et al. 2006	DOE 2006a	N/A	N/A	N/A	Nadel et al. 2006	Nadel et al. 2006	ACEEE estimate	Savings and cost estimates from ACEEE analysis (Nadel et al. 2006).
Efficient clothes washers	DOE 2007	DOE 2007	N/A	N/A	N/A	DOE 2007	Pope 2006	ACEEE estimate	Savings assume MEF of 1.8 (CEE Tier 3 standards) and baseline is 1.26 MEF (DOE 2007 standard).
Efficient new building (15% savings)	ACEEE calc.	EIA 2003	EIA 2003	assumed	ACEEE calc.	NGRID 2007	NGRID 2007	ACEEE estimate	Per-unit savings assume a 100,000 sq. ft. building.
Tax credit eligible building (50% svgs)	ACEEE calc.	EIA 2003	EIA 2003	assumed	ACEEE calc.	ACEEE 2004	NGRID 2007	ACEEE estimate	Per-unit savings assume a 100,000 sq. ft. building. Costs assume $1.80/sq.ft. tax credit.

C.3. Industrial Efficiency Analysis

Overview of Approach

The analysis of electricity savings potential was accomplished in several steps. First, the industrial electricity market in Texas was characterized. Then energy-saving technologies were selected for analysis. The economic potential savings for these measures was estimated. The following sections described the process for estimating the savings potential in Texas.

Methodology for Establishing the Baseline for Electric Savings Potential
The industrial sector analysis process was performed in three steps:

- Estimation of disaggregated industrial sector base-year (2002) electricity consumption for Texas;
- Estimation of a sector base-case electricity consumption forecast; and
- Calculation of electricity savings potential.

Market Characterizations
Estimation of Base Year Electricity Consumption

The industrial sector is made up of a diverse group of economic entities spanning agriculture, mining, construction and manufacturing. Significant diversity exists within most of these industry sub-sectors, with the greatest diversity within manufacturing. The various product categories within manufacturing are classified using the North American Industrial Classification System (NAICS) (Census 2002).[20]

Comprehensive, highly-disaggregated electricity data for the industrial sector is not available at the state level. To estimate the electricity consumption, this study drew upon a number of resources, all using the same classification system and sample methodology. Fortunately, a conjunction of the various economic censuses for each state allows us to use a common base-year of 2002. The major data sources available for Texas State were 2002 Economic Census Subject Series for Mining and Manufacturing (Economic Census).

Unfortunately, disaggregated state-level electricity consumption data was not reported for the sub-sectors (such as chemical, paper, primary metals industries, etc.). Because of the magnitude and diversity in this manufacturing sub-sector, it is important to disaggregate beyond the sub-sector or industry group level (pharmaceutical products under the chemicals industry, for example). As a result, we used national industry electricity intensities derived from industry group electricity consumption data reported in the *2002 Manufacturing Energy Consumption Survey* (MECS) (EIA 2005) and value of shipments data reported in the *2002 Annual Survey of Manufacturing* (ASM) (Census 2005. These intensities were then applied to the value of shipments data for the manufacturing energy groups (three-digit NAICS) in

[20] The industry sector is comprised of four sub-sectors: Manufacturing, Mining, Agriculture, and Construction. Each subsector is further broken down into individual industry groups reflecting the many different definitions for the term 'industrial.'

Texas. These electricity consumption estimates were then used to characterize the share of the industrial sector electricity consumption for each sub-sector.

Preparation of Baseline Industrial Electricity Forecast

As is the case for state level energy consumption data, no state-by-state disaggregated electricity consumption forecasts are publicly available. Several alternate data sources were used to calculate estimated electricity consumption growth rates for each state and sub-sector. We made the assumption that electricity consumption will be a function of gross state value of shipments (VOS). Electricity consumption, however, will not grow at the same rate as value of shipments. This is because in general, energy intensity (energy consumed per value of output) is decreasing with time.

Because state-level disaggregated economic growth projections are not publicly available, data was used from Moody's Economy.com. The average growth rate for specific industrial-subsectors was estimated based on Economy.com's estimates of gross state product. These values were then calibrated to the 2005 industrial electric sales as stated in the 2005 Electric Power Annual.

Eight industrial sub-sectors were chosen to represent manufacturing electricity use in Texas (Table C.5). The sub-sectors include chemicals, petroleum and coal products, primary metals, computer and electronics, food, fabricated metals, non-metallic mineral products, and transportation equipment. In order to simplify the analysis and to obtain information that would be of greatest significance to the state, only sub-sectors with electricity consumption greater than 3% of total Texas industrial consumption were included. The sum of the electricity consumption of these sub-sectors over 83% of total Texas industrial electricity consumption. To simplify the end-use analysis, we applied the end-use consumption of this 83% of the industrial sector to the total 2005 electricity consumption as stated in the Electric Power Annual.

Market Characterization Results

In 2004, the State of Texas industrial sector consumed 100,588,036 MWh of electricity. Within the manufacturing sector, chemical manufacturing (NAICS 325) dominates at 32.3% of the electricity use.

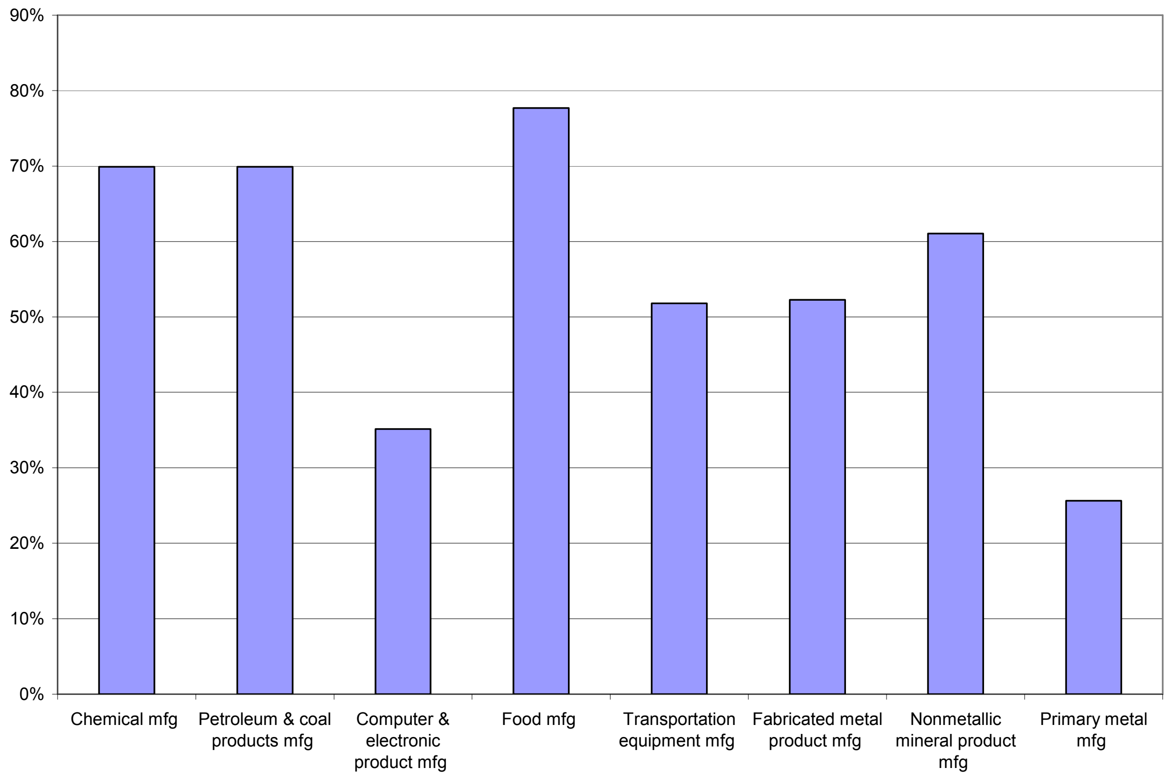
Table C.5. Base-Case Electricity Consumption by Industry in Texas (Calibrated to 2004 Electric Power Annual)

NAICS Code	Industry Name	2004 Base-Case Electricity Consumption (MWh)	Percent of Total Industrial Consumption
325	Chemical mfg	32,489,936	32.3%
324	Petroleum & coal products mfg	14,786,441	14.7%
331	Primary metal mfg	11,165,272	11.1%
334	Computer & electronic product mfg	6,638,810	6.6%
311	Food mfg	6,236,458	6.2%
327	Nonmetallic mineral product mfg	5,129,990	5.1%
332	Fabricated metal product mfg	4,828,226	4.8%
336	Transportation equipment mfg	2,816,465	2.8%
Sub-sector TOTAL		84,091,598	83.8%
Industrial TOTAL		100,588,036	100%

Industrial Electricity End uses

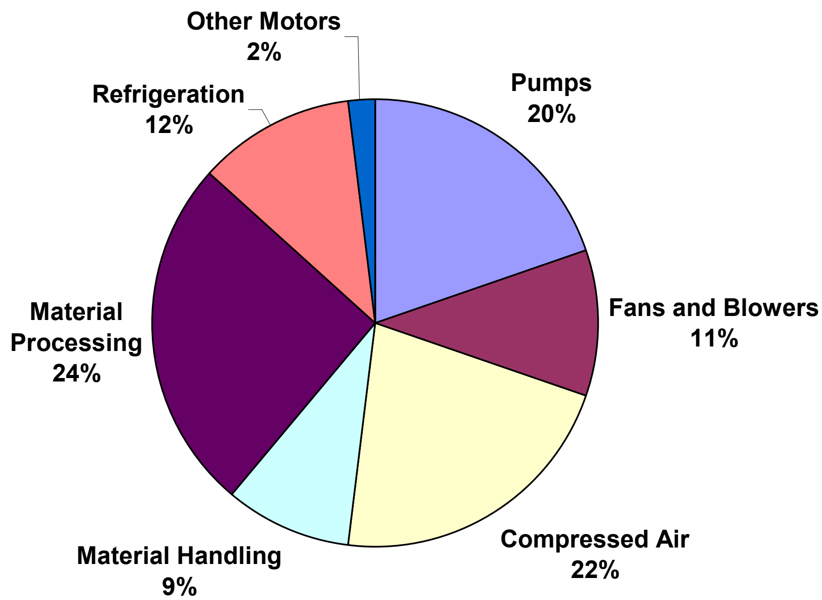
In order to determine the electricity savings for any technology, the fraction of the electricity to which the technology is applicable must be determined. Much of the energy consumed by industry is directly involved in processes required to produce various products. Electricity accounts for about a third of the primary energy used by industries (EIA 2005). Electricity is used for many purposes, the most important being to run motors, provide lighting, provide heating, and to drive electrochemical processes. While detailed end-use data is only available for each manufacturing sub-sector and group through the MECS survey (EIA 2005), motors are estimated to consume 60% of the industrial electricity (Xenergy 1998). The fraction of total electricity attributed to motors is presented in Figure C.6.

Figure C.6. Percent of Total Electricity Consumption by Motors



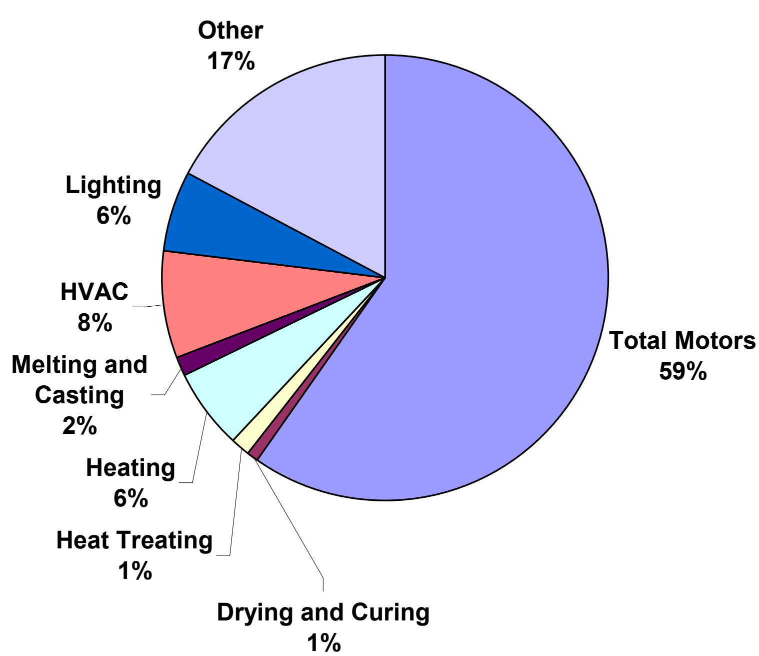
Motors are used for many diverse applications from fluid applications (pumps, fans, and air and refrigeration compressors), to materials handling and processing (conveyors, machine tools and other processing equipment). The distribution of these motor uses varies significantly by industry, with material processing being the largest consumer in the sector. Figure C.7 shows the breakdown of motors use in the state.

Figure C.7. Weighted Average of Industrial Motors Use in Texas



While lighting and space conditioning represent a relatively small share of the overall industrial sector electricity consumption, they are important in some of the key industries found in the region such as transportation equipment manufacture and computer and electronics manufacturing, and the electricity savings potential can be significant. The total weighted average of end-use electricity consumption is included in Figure C.8.

Figure C.8. Weighted Average of Total Industrial Electricity End-Uses in Texas



Overview of Efficiency Measures Analyzed

The first step in our technology assessment was to collect limited information on a broad "universe" of potential technologies. Our key sources of information included the U.S. Department of Energy, Office of Industrial Technologies; the Center for the Analysis and Dissemination of Demonstrated Energy Technologies (CADDET); Lawrence Berkeley National Laboratory (LBNL) and American Council for an Energy-Efficient Economy reports; and information from NYSERDA. We did not collect any primary data on technology performance.

Oftentimes, no one source provided all of the information we sought for our assessment (energy use, energy savings compared to average current technology, investment cost, operating cost savings, lifetime, etc.). We therefore made our best effort to combine readily available information along with expert judgment where necessary.

Electricity Savings Potential: Potential for Energy Savings

We sought to identify technologies that could have a large potential impact in terms of saving energy. These may be technologies that are specific to one process or one industry sector, or so-called "cross-cutting" technologies that are applicable to a variety of sectors. In estimating energy savings, we first identified the specific energy savings of each technology by comparing the energy used by the efficient technology to the energy required by current processes. Our second step was to "scale up" this savings estimate to see how much energy savings—for industry overall—this technology would achieve. For the most part, we derived specific energy savings information from the various technology assessment studies noted above.

In scaling up the technology-specific energy savings, we relied on our general knowledge of the various industrial processes to which this technology could be applied. We also took into account structural limitations to the penetration of the technology. Additionally, we recognized that market penetration, in the absence of significant policy support, can take time given the slowness of stock turnover in many industrial facilities.

APPENDIX D: DEMAND RESPONSE

D.1.1 Background—Demand Response in ERCOT

The Department of Energy defines demand response as, "changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized." (DOE 2006c). Demand response measures include incentive-based programs that pay users to reduce their electricity consumption in specific times (such as load management and direct control to turn down customers' heaters or air conditioners in an emergency situation), or pricing programs such as time-of-use rates, critical peak pricing, or real time pricing, where customers are given a price signal and expected to moderate their electricity usage in times when prices are high. Most early demand response programs were incentive-based and control-oriented, so the utilities could operate and control the customers' usage and tell exactly when and how much load changed; operators view these are viewed as reliable, predictable programs that can be trusted as a resource to meet grid reliability needs (as distinguished from price-responsive demand, the impact of which is harder to forecast and measure).

Over the near term, given Texas's tight capacity situation, incentive-based, emergency-oriented demand response programs will be most effective at lowering effective peak loads and moderating supply scarcity. Over the long term, however, once ERCOT's nodal market is in full operation and many ERCOT retail electric consumers have advanced interval meters, more customers should and could take advantage of time-varying rates such as critical peak pricing or real-time pricing, and price-responsive demand response should have a far greater impact upon peak loads and prices than incentive-based programs. Today we have no data to estimate the possible impact of time-varying rates upon electricity consumption, and it will take years to collect and analyze such data; therefore, this study estimates only the potential for incentive-based, emergency-oriented demand response measures upon ERCOT's supply to demand balance. By 2023, however, it is likely that the widespread availability of time-varying retail electric rates and complementary communications and control methods will have permanently changed the nature of Texas's electricity demand, making today's forecasts for ever-increasing demands obsolete.

The ERCOT market began wholesale competition in 1995 and retail competition in 2002. Before the start of retail competition, Texas's integrated utilities offered a variety of direct load control and time of use, curtailable and interruptible rates, with almost 3,500 MW of loads participating (primarily from Texas's base of industrial facilities). However, with the advent of retail competition in ERCOT and the structural unbundling of the investor-owned utilities, much of this demand response capability was lost to new market complexities and higher transactions costs.

There is less demand response available in ERCOT today, and in more limited forms than were available before competition. ERCOT has a real-time energy market (and no capacity market), and customers with loads at or above 700 kW have interval data recorders (meters that record energy use over time). The following types of demand response are in use today:

- *Load acting as a Resource (LaaR) serving as Responsive Reserve*—1,150 MW (the maximum allowed in the market for this product at any point in time), although 115 customers (all large industrial users, like petrochemical plants) offering 1,875 MW are registered as qualified LaaR providers. These customers drop load either automatically when the bulk power system needs it for frequency restoration (triggered automatically by under-frequency relays at the customers' sites) or upon request by ERCOT. LaaR is bid into the Responsive Reserve market. In 2006 LaaR provided 10,055 GWh in load capacity to respond to system emergencies, and received $48.4 million in payments.[21] In late 2006 the average price paid for Responsive Reserve Service was about $13.00/MW.

- *Voluntary Load Response*—It is estimated that more than 600 MW of large industrial and commercial customers have contracts with their retail electric providers (REP) to lower their electric load upon request. The contract between the customer and the REP may or may not offer an extra incentive for the peak load reduction, which helps the REP manage its energy purchase portfolio and costs. ERCOT transmission charges for one year are based on grid users' maximum demands during the monthly coincident peaks in June through September. Therefore, several retail electric providers give warnings to their commercial and industrial customers to lower load on days in those months when a coincident peak is likely to occur. They do so because the value of avoided transmission charges can exceed $2,500 per MW in one 15 minute period if it is one of the four monthly coincident peaks—i.e., transmission charge avoidance is worth significantly more than the avoided energy costs. This is voluntary or contractual behavior that is not tracked or formally recognized as an ERCOT resource.

- *Active Price Response*—There are no compiled data on how many customers within ERCOT are actively monitoring ERCOT's 15-minute energy price feed and responding to price levels in real time. Research by Zarnikau et al. (2005) of the largest industrial energy consumers in Houston indicates that only 2 out of 20 were actively managing their loads in response to prices. Before 2006, among the retail competitive loads, only customers with loads greater than 700 kW had interval data recorders that could track time-varying energy uses, so the pool of customers with both the capability and sophistication to do so was limited.

- *Muni and Coop Demand Response programs*—ERCOT's municipal and cooperative utilities, which are not subject to retail competition and are outside the regulation of the PUCT, offer more demand response options than the competitive retail electric providers. Several of the munis offer time of use rates and direct load control programs, while many of the rural coops offer direct load control for irrigation pumping and other uses.

[21] S. Krein, "Load Participation in ERCOT Ancillary Service Markets," April 18, 2006, AESP Brown Bag Seminar, and personal communications.

- *LaaR serving as Non-Spinning Reserve*—although ERCOT allows demand resources to compete against generators to provide non-spinning reserve, as of mid-2006 few end-users were actually providing this service. For 2005, LaaRs provided less than two percent of non-spinning reserve sales; one ERCOT observer remarks that, "providing responsive reserves offers substantial revenue with very little probability of being deployed [but] providing non-spinning reserves introduces a much higher probability of being curtailed."[22]

- *Balancing-Up Load*—Although ERCOT has defined the rules for customer (through Qualified Scheduling Entities) to bid their loads into the real-time energy market, only one customer has qualified to do so at present. Principal reasons given for the lack of BUL participation are that most of the potential participants are already committed to provide Responsive Reserve (LaaR) service, and that prices in the balancing energy market are not high enough to attract load participation.

Several factors affect and limit the demand response options that are available within ERCOT today and for the near term:

1. The PUCT formally limits the ERCOT transmission and distribution utilities' (TDUs) ability to offer demand response programs; this is in keeping with Texas's energy efficiency model, under which the TDUs administer efficiency programs but third party energy service providers deliver the actual efficiency measures to end users. While this is consistent with Texas's goal of allowing retail electric providers to develop specific and varying business strategies and customer relationships, it prevents the development of relationships between the transmission and distribution utility (which can benefit from high impact demand response programs) and its many customers.

2. Because so many customers are billed according to load profiles (have imputed energy use patterns with flat energy rates), they do not see any time-varying charges and have no bill consequences or incentives to moderate electricity use to reflect short-term price changes. Until recently, utilities were only required to install advanced interval meters on customers with more than 700 kW peak load; however, TXU-Electric Delivery has made commitments to install advanced meters and supporting communications networks on all customer accounts within five years, and CenterPoint is on a similar path, so that barrier could change relatively soon.

3. The Public Utility Commission of Texas has made a policy decision that ERCOT will remain an energy-only market; in most other regions and wholesale markets, capacity payments ($/kW of load relief at a specific point in time) provide a supplemental stream of revenues to demand response and peak generators, on top of energy payments ($/kWh sold). Revenues from energy markets are reduced further by active market mitigation, imposed by the Public Utility Commission to protect customers from potential market power and price manipulation by generators—for example, on April 17, 2006, when ERCOT faced a generation shortfall relative to demand and initiated involuntary rolling blackouts, energy prices at peak were "post-mitigated" from $598/MWh down to

[22] "ERCOT 2005 State of the Market Report," Potomac Economics, page 107.

$210/MWh (Wattles 2006). Although price caps for market mitigation have been raised since that time, active ex ante market mitigation and price caps distort the effectiveness of real-time market prices to signal the need for and value of customer load reductions.

5. Since vertically integrated utilities were unbundled before the start of retail competition in ERCOT in 2002, the benefits of demand response are diffused and spread across multiple layers of beneficiaries, making it difficult to establish cost-effectiveness and reap the monetized benefits from demand response in the same way that a vertically integrated utility can.

6. Demand response providers (such as aggregators), generators, and load-serving entities (also called retail electric providers) do not participate directly in ERCOT's centralized wholesale market. Instead, they interact with the market through intermediaries called Qualified Scheduling Entities, so demand response providers and load-serving entities contract directly with their QSE, which may manage demand response as part of its internal portfolio rather than selling it into the ERCOT market.

7. Effective January 2007, most of ERCOT's load-serving entities are no longer subject to rate regulation by the Public Utility Commission of Texas. Therefore, regulators cannot mandate time-of-use rates for broad groups of customers.

D.2. Estimating Potential Demand Response in ERCOT

The preferred academic way to estimate the potential impact of demand response for affecting customer energy and capacity use is to use sophisticated statistical analysis and forecasting techniques with detailed information on several critical topics:

- Extensive demographic data, including customer counts by class and sub-class (e.g., residential with and without interval meters, small commercial, large industrial, educational, office, etc.),
- Up-to-date load research data on the patterns and specifics of energy use by customer group,
- Penetration levels and energy use characteristics for key appliances and energy uses per customer class and sub-class (e.g., high-SEER central air conditioner saturation, age of window air conditioner fleet, efficiency of refrigeration units),
- Regional coincident and non-coincident peak demand for the region, broken out by customer class,
- Estimated elasticities of demand by customer class and sub-class, to understand how each group will respond to changes in the price of electricity, which are based upon historical data on actual customer choices under time-varying electricity prices (as from critical peak pricing or real-time pricing),
- And, the ability to predict with some confidence what rates and programs will be in place in the region studied.[23]

[23] Examples of DR potential estimation studies include Quantec's *PacifiCorp Demand Response Proxy Supply Curves* (2006), Gunn's *Estimating Demand Response Market Potential, Final Report to the International*

Unfortunately, none of this information exists for the customers within ERCOT, for several reasons that have evolved since ERCOT moved to retail competition in 2001:

- Although the TDUs are responsible under statute for providing energy efficiency services to all end use customers within their footprints, they no longer perform services such as load research.
- Competitive retail electric providers (REPs) do not share information such as customer counts and load subscription to their various rate offerings (including any time of use or real-time pricing rates) because that competitively sensitive information could allow other REPs to gain market advantage.
- Because each REP is unregulated (with the exception of the REPs affiliated with the incumbent TDUs, for "Provider of Last Resort" customers), they can offer any rates they want and change those rates at any time.
- Among the customers served by competing retail electric providers, those customers with demand below 700 kW do not yet have interval data recorders, so their energy and demand is estimated and settled based on 8 load profiles (each modified for ERCOT's 8 weather zones) that were developed in 1999. Thus most ERCOT customers' detailed energy usage is assumed to exist independent of prevailing energy price levels or real-time price fluctuations, and those customers are not exposed to actual price variations.
- Cooperative and municipally owned utilities serve approximately 20% of the load within ERCOT, and they do not have to report any detailed information to ERCOT or the Public Utility Commission of Texas about their customers' energy uses. In sum, other than totals for the number of meters within the investor-owned TDUs and the total coincident and non-coincident peak demand figures, there are no data available to develop a credible estimate of the potential impact of demand response within ERCOT.

Absent the ability to develop a systematic, class-specific, elasticity-based technical or market potential DR estimate, we must look to other methods to estimate market potential. One option might be to use demand elasticities developed for customers in other regions (most notably California, New York, and Oregon) as the basis for estimating Texas customer responses—however, there are so many substantive differences between Texas and those other regions in terms of both customer electricity needs and desires and retail and wholesale market structures that the demand elasticity curves and underlying assumptions would not produce defensible results for ERCOT. Therefore, it is necessary to use cruder approximations for this purpose.

To estimate the potential for increased demand response in Texas, this analysis makes very limited assumptions with respect to what demand response mechanisms will be used over the forecast period. For residential customers, we assume that their only demand response option will be direct load control over air conditioning, with one additional appliance, to be cycled on and off each hour during the needed period. This assumes that,

Energy Agency Demand Side Management Programme, Task XIII (2005), and various studies by Braithwait et al. on the impact of California's statewide pricing pilot.

similar to plans in California, all new residential construction in Texas beginning in mid-2008 is required to install a smart, two-way communicating thermostat that can receive load control signals, and that increasing numbers of such devices are installed and used over time under TDU-managed demand response programs. For commercial and small industrial facilities, we assume that they use energy management systems that can reduce on-peak demand by at least 5% per site in the early years, and 20% per site by 2023,[24] and that new non-residential construction is mandated to install and use energy management systems beginning in mid-2008. For industrial sites, we assume that ERCOT and the Public Utility Commission will increase the amount of Load as a Resource allowed for use as Responsive Reserve. Additionally, ERCOT and the PUCT will create some mechanism to allow the remaining LaaR customer load to offer their reductions into the market when needed (rather than only as emergency responsive reserve), and that more customers will voluntarily reduce their load to avoid transmission charges.

Since air conditioning direct load control has already been used extensively within Texas by the City of Austin, City Public Service of San Antonio, and Houston Light & Power (although that program has since been abandoned due to retail restructuring), and is widely used and being expanded in Florida, California and other states, it is clear that this technology is cost-effective today. The challenge in ERCOT is not with the low cost of such options, but whether and how to apportion the benefits and costs of demand response when there is no vertically integrated utility to internalize the benefits; we recommend that since Texas's electricity customers ultimately benefit from demand response (even if those benefits cannot be fully monetized by any one market participant), the costs and the burden of program delivery should be placed upon the transmission and distribution utility since it serves all end users. Similarly, the other demand response methods included in these calculations are already in commercial use in Texas and elsewhere and therefore are by definition cost-effective.

Using these limited program assumptions with conservative penetration and impact rates, we estimate the following load reductions due to demand response:

- in 2013, 1,549 MW from residential users, 954 MW from commercial users, and 960 MW from industrial users, totaling 3,463 MW and 4.1% of peak load;

[24] The Lawrence Berkeley National Laboratory's Demand Response Research Center's reports indicate that automated demand response for commercial customers has delivered 5-10% peak load reductions in medium-sized commercial sites; this is confirmed by Southern California Edison research, which has achieved up to 25% demand reductions for small commercial customers. Site Controls, a Texas-based energy management company, is delivering sustained peak load reductions of over 30% to its small commercial customers using technology that is commercially cost-effective today.

- in 2023, 5,540 MW from residential users, 6,551 MW from commercial users, and 1,150 MW from industrial users, totaling 13,241 MW and 12.5% of peak load.

Table D-1 shows the detailed calculations underlying these assumptions and results.

Table D-1. Detailed Savings and Cost Calculations for Expanded Demand Response Programs

Texas assumptions	1/31/2007															
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Total projected summer demand (MW)	**75,668**	**77,588**	**79,468**	**81,216**	**83,014**	**84,850**	**86,728**	**88,647**	**90,608**	**92,646**	**94,730**	**96,861**	**99,039**	**101,267**	**103,545**	**105,874**
RESIDENTIAL																
Households (thousand)	8,698	8,883	9,077	9,267	9,461	9,668	9,881	10,097	10,317	10,529	10,740	10,946	11,151	11,353	11,548	11,742
Total households	8,698,486	8,883,464	9,077,060	9,266,764	9,461,394	9,668,056	9,880,508	10,097,120	10,316,590	10,529,240	10,739,930	10,946,440	11,150,510	11,352,570	11,548,160	11,742,490
New housing completions -- mandatory AC-DLC	30,000	191,825	195,514	203,540	210,432	216,805	219,508	223,995	232,819	238,393	242,174	243,213	243,384	244,616	244,995	244,953
Existing households getting AC-DLC	10,000	50,000	50,000	75,000	75,000	100,000	100,000	100,000	100,000	125,000	125,000	125,000	125,000	150,000	150,000	150,000
Total households in AC-DLC (prior year total + new AC-DLC)	40,000	281,825	527,339	805,880	1,091,312	1,408,117	1,727,625	2,051,620	2,384,438	2,747,831	3,115,005	3,483,218	3,851,602	4,246,218	4,641,213	5,036,166
MW load reduction from res AC-DLC - households x 1kW	**44**	**310**	**580**	**886**	**1,200**	**1,549**	**1,900**	**2,257**	**2,623**	**3,023**	**3,427**	**3,832**	**4,237**	**4,671**	**5,105**	**5,540**
Residential AC-DLC as % of peak load	**0.1%**	**0.4%**	**0.7%**	**1.1%**	**1.4%**	**1.8%**	**2.2%**	**2.5%**	**2.9%**	**3.3%**	**3.6%**	**4.0%**	**4.3%**	**4.6%**	**4.9%**	**5.2%**
COMMERCIAL																
Commercial Bldg Floorspace (mil. Sq. ft.)	6,822	7,003	7,190	7,381	7,577	7,779	7,986	8,198	8,416	8,640	8,870	9,106	9,348	9,597	9,852	10,114
Number of small non-residential meters	1,441,000	1,469,820	1,499,216	1,529,201	1,559,785	1,590,980	1,622,800	1,655,256	1,688,361	1,722,128	1,756,571	1,791,702	1,827,536	1,864,087	1,901,369	1,939,396
New commercial bldgs w/ mandatory EMS/DLC	0	0	29,396	29,984	30,584	31,196	31,820	32,456	33,105	33,767	34,443	35,131	35,834	36,551	37,282	38,027
Existing non-residential bldgs getting EMS/DLC	5,000	5,000	7,500	7,500	10,000	10,000	10,000	15,000	15,000	15,000	15,000	20,000	20,000	20,000	25,000	25,000
Total new small non-residential bldgs w/ EMS/DLC	5,000	10,000	46,896	84,381	124,965	166,160	207,980	255,436	303,541	352,308	401,751	456,882	512,716	569,267	631,549	694,576
Avg peak load reduction per small building (kW)	5	5	5	5	5	8	8	8	8	8	12	12	12	12	12	12
MW peak load reduction from small non-residential	**25**	**50**	**234**	**422**	**625**	**954**	**1,289**	**1,669**	**2,053**	**2,444**	**3,037**	**3,698**	**4,368**	**5,047**	**5,794**	**6,551**
small non-residential as % of peak load	**0.0%**	**0.1%**	**0.3%**	**0.5%**	**0.8%**	**1.1%**	**1.5%**	**1.9%**	**2.3%**	**2.6%**	**3.2%**	**3.8%**	**4.4%**	**5.0%**	**5.6%**	**6.2%**
INDUSTRIAL																
Large non-residential meters	4,790	4,862	4,935	5,009	5,084	5,160	5,238	5,316	5,396	5,477	5,559	5,642	5,727	5,813	5,900	5,989
Industrial LAAR for Responsive Reserve (MW)	1,150	1,150	1,150	1,150	1,250	1,250	1,250	1,250	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300
Other LAAR resources (MW)	650	700	700	750	750	750	800	800	800	800	800	800	800	800	800	800
Industrial peak avoidance (MW)	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200	200
MW peak load reduction from industrial (less 1150 LAAR)	**710**	**770**	**780**	**840**	**950**	**960**	**1,020**	**1,030**	**1,090**	**1,100**	**1,110**	**1,120**	**1,130**	**1,140**	**1,150**	**1,150**
Industrial reduction as % of peak load	**0.9%**	**1.0%**	**1.0%**	**1.0%**	**1.1%**	**1.1%**	**1.2%**	**1.2%**	**1.2%**	**1.2%**	**1.2%**	**1.2%**	**1.1%**	**1.1%**	**1.1%**	**1.1%**
Total peak reduction from demand response																
MW	**779**	**1,130**	**1,595**	**2,148**	**2,775**	**3,463**	**4,209**	**4,955**	**5,766**	**6,566**	**7,573**	**8,650**	**9,735**	**10,858**	**12,050**	**13,241**
% of peak	**1.0%**	**1.5%**	**2.0%**	**2.6%**	**3.3%**	**4.1%**	**4.9%**	**5.6%**	**6.4%**	**7.1%**	**8.0%**	**8.9%**	**9.8%**	**10.7%**	**11.6%**	**12.5%**
COSTS																
res -- $100/kW installation	1,000,000	5,000,000	5,000,000	7,500,000	7,500,000	10,000,000	10,000,000	10,000,000	10,000,000	12,500,000	12,500,000	12,500,000	12,500,000	15,000,000	15,000,000	15,000,000
res -- $50/kW on-going	2,000,000	14,091,255	26,366,967	40,293,976	54,565,584	70,405,828	86,381,228	102,580,978	119,221,915	137,391,548	155,750,261	174,160,900	192,580,119	212,310,907	232,060,651	251,808,305
Commercial -- $3000/installation	15,000,000	15,000,000	22,500,000	22,500,000	30,000,000	30,000,000	30,000,000	45,000,000	45,000,000	45,000,000	45,000,000	60,000,000	60,000,000	60,000,000	75,000,000	75,000,000
Commercial -- $50/kW on-going	250,000	500,000	2,344,820	4,219,036	6,248,237	8,308,022	10,399,002	12,771,802	15,177,058	17,615,420	20,087,548	22,844,119	25,635,821	28,463,358	31,577,445	34,728,814
Industrial -- $40/kW-yr	28,400,000	30,800,000	31,200,000	33,600,000	38,000,000	38,400,000	40,800,000	41,200,000	43,600,000	44,000,000	44,400,000	44,800,000	45,200,000	45,600,000	46,000,000	46,000,000
Industrial -- $10,000/kW installation after 1900 MW	0	0	0	500,000	2,400,000	2,500,000	3,100,000	3,200,000	3,800,000	3,900,000	4,000,000	4,100,000	4,200,000	4,300,000	4,400,000	4,400,000
Total cost																
investment cost	16,000,000	20,000,000	27,500,000	30,500,000	39,900,000	42,500,000	43,100,000	58,200,000	58,800,000	61,400,000	61,500,000	76,600,000	76,700,000	79,300,000	94,400,000	94,400,000
operations cost	30,650,000	45,391,255	59,911,787	78,113,012	98,813,821	117,113,850	137,580,230	156,552,780	177,998,973	199,006,968	220,237,809	241,805,018	263,415,940	286,374,265	309,638,096	332,537,118
TOTAL	**46,650,000**	**65,391,255**	**87,411,787**	**108,613,012**	**138,713,821**	**159,613,850**	**180,680,230**	**214,752,780**	**236,798,973**	**260,406,968**	**281,737,809**	**318,405,018**	**340,115,940**	**365,674,265**	**404,038,096**	**426,937,118**

D.3. Detailed Demand Response Policy Recommendations

Customer data collection—Texas policymakers and market designers will not be able to design effective, predictable demand response or energy efficiency programs until they remedy the current dearth of information on customer energy uses and consumption. The Legislature should mandate the following activities for the PUCT, REPs, and all of the state's utilities (including cooperatives and municipals). All retail electric providers and vertically-integrated utilities should collect the following data and submit annual reports (to be aggregated to preserve commercially sensitive data for each provider) on:

- Customer counts by pre-defined class and sub-class
- Hourly load profiles (i.e., aggregated class energy and demand across the entire year) by pre-defined class and sub-class, based on new research and data collection.

Load research—All transmission and distribution utilities, including those within vertically integrated utilities outside ERCOT and all cooperatives and municipally-owned utilities, should be required to conduct a load research survey and an appliance saturation census no less than every five years, beginning in 2008. These survey and census results should be designed under the supervision of the PUCT, to assure that they achieve sufficient granularity with respect to location, customer class and climate zone to be of maximum value, and could be conducted statewide by a single contractor for maximum cost-efficiency. The load research and appliance saturation findings should be shared with all utilities, REPs, regulators and interested parties to facilitate design of more effective energy efficiency, demand response, and system planning across the state. ERCOT is already working with the TDUs under PUCT Substantive Rule 25.131 to conduct load research to update load profiles.

Load profiling and IDRs—Texas's two largest TDUs, TXU Electric Delivery and Centerpoint, have begun a multi-year process of installing advanced IDR meters for their millions of end-use customers. The Legislature or the PUCT should mandate that after January 1, 2008, every customer with an interval meter should have his or her electricity bill be settled on metered use rather than according to the pre-defined load profiles.

Additionally, ERCOT should work with the TDUs and the PUCT to begin warehousing customer load data and price responses for future analysis.

Deploy more advanced meters—Once TXU-ED and Centerpoint have more experience with their advanced meter programs, the PUCT should review those experiences and require the other investor-owned TDUs to install advanced meters for all of their customers. Given ERCOT's data management limitations, the PUCT should work with the REPs and TDUs to determine how and where these massive data records should be managed and archived while protecting ERCOT's settlement responsibilities. Expiration of the Price-to-Beat mechanism in 2007 will remove a price protection for retail electric providers and give both those providers and retail customers more motivation to aggressively manage their energy use and costs. Therefore, the Legislature should mandate that every electricity user in Texas have an interval data recorder, and access to at least one or more time-of-use rate or emergency load reduction option by 2012.

Refine and distribute DR-enabling technologies to target customers—An advanced meter archives how a customer's electricity use varies over time, but it neither delivers a price or reliability signal nor helps the customer moderate her electricity use in response to that signal. To achieve substantive increases in DR by customers outside the large commercial and industrial sectors, Texas will need to invest some thought and money in: a) designing price signals and incentives that motivate customer responses (e.g., critical peak pricing or bill credits for air conditioner direct load control), (b) effective ways to deliver those signals to customers (e.g., as through California's radio-directed electricity orb or day-ahead e-mail messages indicating the following day's electricity prices or needs), and (c) automating ways for customers' key electricity uses to change without great cost or inconvenience (e.g., direct load control for residential appliances, energy service company dispatch of commercial and industrial distributed generators, or internet-enabled building automation for commercial and industrial customers).

- Given that air conditioner direct load control (through radio or internet controls that turn off a customer's air conditioner for 20 minutes each hour) produces one kW of load reduction per participating Texas air conditioner (cycling between three 3-kW air conditioners in one hour delivers one steady kW of load reduction per customer), AC-DLC has proven to be one of the single most effective, cost-effective, dispatchable reliability demand response options available in other states. Air conditioning represents over 40% of Texas's summer peak load. AC-DLC should be the primary new reliability demand response program pursued within ERCOT in the next five years, implemented by the TDUs (through contractors) with full cost recovery. Wherever possible, each AC-DLC installation should control more than one appliance (adding an electric water heater or pool pump to be cycled along with the air conditioner) to increase the impact and cost-effectiveness of the overall program.
- The Legislature should mandate that all new residential construction in Texas should have two-way communicating smart thermostats installed, with a link to manage any electric water heater or pool pump on the property under the same control signal.
- The small commercial market, which makes up as much as 30% of ERCOT's peak load, is under-served for both energy efficiency and demand response. However, new technology and market developments for automated energy use in small commercial buildings offer cost-effective options for fully dispatchable, highly granular control over electricity use, with peak load reductions in excess of 30%. These should be aggressively pursued through third-party provider programs.
- If customers do not have automated means to manage their electricity use in real time, they will need advance notice—preferably day-ahead—of upcoming price and reliability conditions and needs, so they can plan and implement energy use accordingly. The PUCT and ERCOT should design an advance forecasting method and DR price or need signal to meet this need. Advance notice about price and need conditions will also enhance customers' ability to deliver deeper, longer load reductions using automated demand response technologies.

Demand response portfolio requirements—Given that demand response has system-wide price and reliability benefits, every REP and TDU should have to provide a minimum amount of demand response, in proportion to its load. Since ERCOT's planning reserve margin requirement is 12.5% (generation over peak demand) as a reliability requirement, and forced outages and load forecast error currently swing the load-to-generation balance by 3,500 MW (6% of 2006 peak load), each REP should be required to procure no less than 3% of its peak demand from demand response by 2011, 6% by 2017, and 12% by 2023. This can include price-responsive demand based on measured, long-term validation that the price signal is being delivered and customers are responding in a statistically measurable fashion.

- Controllable, dispatchable demand response (as from curtailment instructions, direct load control or building automation) should be exercised no less than two times per year, and verified by IDR readings.
- Price-responsive demand response (as from critical peak pricing) should be measured and statistically validated over time, to give the PUCT and ERCOT confidence that price signals are eliciting non-trivial load changes.
- Demand response options meeting the portfolio requirements could be offered by retail electric providers, energy service providers or electricity curtailment providers. TDUs should be responsible for delivering a portion of the REPs' demand response requirement.
- To contain program costs and competition without squashing innovation, TDUs should coordinate demand response offerings from third party providers in a similar fashion to their coordination of energy efficiency offerings. All TDU administrative costs to manage these programs should be recovered in rates, with an incentive for meeting demand response goals (in part to compensate for the reduced kWh volumes the utility will be delivering over the long term). TDU budgets for demand response should increase over time in relation to population served and load growth.
- However, TDUs should be allowed to directly manage and market (or contract) demand response programs designed to deliver location-specific transmission and distribution benefits (i.e., congestion reduction, reliability-protecting, or capital deferral). To fulfill this responsibility, TDUs should be allowed to co-own and operate low-emissions distributed generation in partnership with customers in reliability-compromised areas.
- A portion of each TDU's demand reductions should be allocated proportionally to the REPs serving its customers.
- Demand response reductions should be certified and tradable between REPs in the same fashion that Renewable Energy Credits are traded, so that REPs and energy service companies can make or buy demand response as best suits their market model, strengths, and customer base. REPs with more than 112.5% of their demand and an excess of demand response above their required level should be able to sell their DR credits to other REPs.
- Unlike Texas's energy efficiency programs, demand response responsibility should not be allocated in quotas among specified customer classes or groups, nor assigned (over the long term) to specific technologies. Different classes of customers have widely differing amounts of load that they can give up at any point in time, with varying elasticities of demand, and the level of infrastructure and transactional costs vary significantly among demand response offerings and customers. Over-detailed mandates for specific types of programs or class contributions to demand response

targets will raise the costs of demand response to all participants and offerors, lower the likelihood of attaining demand response targets, and violate Texas's tradition of competitive provision of such services.

Cover all TDU costs of demand response management and pay incentives for good DR performance—To the degree that accelerating the penetration of highly effective, controllable demand response requires investment in these technologies, those investments should be funded by ERCOT's transmission and distribution utilities, which should receive ratebase or expensing cost recovery for all prudent, PUCT- or ERCOT-directed demand response expenditures. The TDUs should also receive an incentive for exceeding its demand response targets, for using demand response to manage new transmission and distribution capital needs, and for facilitating creative demand response efforts by retail electric providers.

Raise the 50% limit on LaaR for Responsive Reserve—ERCOT now has several years of experience with LaaR provision of ancillary services, and should be able to understand and manage load impacts effectively as ERCOT's generation grows. If lumpy demand reductions remain a concern (too much load dropping off on under-frequency at once, causing an excessive frequency recovery), ERCOT should be able to modify its under-frequency set-points and load allocations to smooth out LaaR responses. Additionally, ERCOT should increase the allowed quantity of LaaR accepted as the region's load and generation resources rise.

Bidding demand response into the wholesale electricity market—ERCOT reports that it cannot handle loads bidding demand reductions directly into the wholesale electricity spot market (as distinguished from the ancillary services product markets) because this would make it impossible for its Security-Constrained Economic Dispatch and Unit Commitment software to properly converge (i.e., the software needs a fixed load target against which to assign competing generation bids). ERCOT's current information technology priority is (and should be) to achieve nodal market opening in 2009. However, once the nodal market is in place, the PUCT should direct ERCOT to figure out how to let demand resources bid into that market against generation, and implement that solution within two years of the nodal market transition.

Raise or remove wholesale market price caps—The existence of price caps, bid mitigation or price mitigation on generators reduces the magnitude and volatility of wholesale market prices, including price spikes due to scarcity rather than possible generator market power abuse. Price caps were initially adopted within ERCOT to operate in lieu of demand response, which was expected to act as a check upon supplier market power and create slack in times of generation scarcity. Therefore, the PUCT should commit to raise (lighten) market mitigation and price caps as the amount of demand response within ERCOT grows over time, even removing it entirely once more than 10% of ERCOT load has the capability and opportunity to respond to price and reliability signals.

Information availability—Customers need good information about current and forecast peak and energy use—their own, and the entire electricity system—to make good decisions about demand response. While ERCOT does good reporting about big issues like transmission constraints, its day-to-day information about current and forecasted loads, supply, prices, and congestion is limited, opaque, and difficult to access. ERCOT could help all customers (and perhaps even its own wholesale partners) by improving the amount, type and quality, relevance and understandability of system condition information it makes available on its website.

Invest in education about demand response—Before the start of Texas retail electric competition, the state invested millions of dollars in an educational campaign to explain the purpose and benefits of retail competition and how customers could participate. Demand response does not require a mass-market campaign, but it does require systematic outreach to recruit, train and retain customer participants. Since the reliability and price reduction benefits of demand response participants benefit every ERCOT member and end-user (whether competitive or non-competitive), demand response education costs should be funded through wires charges to all ERCOT transmission providers.

Measure cost-effectiveness—Even though no one entity can capture the full benefits of demand response, its benefits as a public good are significant and unquestionable. Therefore, the PUCT should set up a cost-effectiveness method similar to that established in its Energy Efficiency programs, and recognize the capacity value of DR programs despite the fact that ERCOT does not run a capacity market. The cost-effectiveness framework for demand response should be designed to recognize and reward DR contributions in non-peak periods as well as at summer peak.

Make multi-year commitments for reliability demand response—Retail electric providers, demand response aggregators and customers will not invest in demand response measures if there is any question about how long the program will be in operation, or whether its terms will change in mid-stream. Given the extended experience with demand response programs within Texas and nation-wide, the PUC and ERCOT should be able to design and implement an effective framework and rules for demand response that can be implemented with at least a 4 to 5-year term with minimal changes over that period.

Reconsider EILP—ERCOT's proposed Emergency Interruptible Load Program is designed to be the last step in the region's emergency response protocols, triggered after a series of measures that include calling out all demand response programs and raising generation from all available power plants. As voluntary load-shedding, the EILP may be worth doing as a last-ditch measure to prevent involuntary load-shedding (i.e., rolling blackouts), but it will not offer any of the customer participation, market discipline, or operational reliability benefits of more price- and situationally-responsive options and programs. Furthermore, the EILP prevents the participating customers from offering any of their EILP-committed load into other demand response programs, so it is preventing many of the most suitable customers from helping to expand price- and market-responsive demand response levels within ERCOT.

APPENDIX E: ECONOMIC POTENTIAL ASSESSMENT APPROACH AND DETAILED TABLES: COMBINED HEAT AND POWER SYSTEMS

E.1. Introduction

This section provides an estimate of the technical market potential for combined heat and power (CHP) in the industrial, commercial/institutional, and multi-family residential market sectors. The estimation of technical market potential consists of the following elements:

- Identification of applications where CHP provides a reasonable fit to the electric and thermal needs of the user.
- Target applications were identified based on reviewing the electric and thermal energy consumption data for various building types and industrial facilities.
- Quantification of the number and size distribution of target applications. Several data sources were used to identify the number of applications by sector that meet the thermal and electric load requirements for CHP.
- Estimation of CHP potential in terms of megawatt (MW) capacity. Total CHP potential is then derived for each target application based on the number of target facilities in each size category and sizing criteria appropriate for each sector.
- Subtraction of existing CHP from the identified sites to determine the remaining technical market potential.

The technical market potential does not consider screening for economic rate of return, or other factors such as ability to retrofit, owner interest in applying CHP, capital availability, natural gas availability, and variation of energy consumption within customer application/size class. The technical potential as outlined is useful in understanding the potential size and size distribution of the target CHP markets in the state. Identifying technical market potential is a preliminary step in the assessment of market penetration.

The basic approach to developing the technical potential is described below:

- *Identify applications where CHP provides a reasonable fit to the electric and thermal needs of the user*. Target applications were identified based on reviewing the electric and thermal energy (heating and cooling) consumption data for various building types and industrial facilities. Data sources include the DOE/EIA *Commercial Buildings Energy Consumption Survey (CBECS),* the DOE *Manufacturing Energy Consumption Survey (MECS),* and various market summaries developed by DOE, Gas Technology Institute (GRI), and the American Gas Association. Existing CHP installations in the commercial/institutional and industrial sectors were also reviewed to understand the required profile for CHP applications and to identify target applications.

- *Quantify the number and size distribution of target applications*. Once applications that could technically support CHP were identified, the iMarket, Inc. *MarketPlace Database* and the *Major Industrial Plant Database* (MIPD) from IHI were utilized to identify potential CHP sites by SIC code or application, and location (county). The *MarketPlace Database* is based on the Dun and Bradstreet financial listings and includes information on economic activity (8 digit SIC), location (metropolitan area, county, electric utility service area, state) and size (employees) for commercial, institutional and industrial facilities. In addition, for select SICs limited energy consumption information (electric and gas consumption, electric and gas expenditures) is provided based on data from Wharton Econometric Forecasting (WEFA). MIPD has detailed energy and process data for 16,000 of the largest energy consuming industrial plants in the United States. The *MarketPlace Database* and MIPD were used to identify the number of facilities in target CHP applications and to group them into size categories based on average electric demand in kilowatt-hours.

- *Estimate CHP potential in terms of MW capacity.* Total CHP potential was then derived for each target application based on the number of target facilities in each size category. It was assumed that the CHP system would be sized to meet the average site electric demand for the target applications unless thermal loads (heating and cooling) limited electric capacity. **Tables E-1 and E-2** present the specific target market sectors, the number of potential sites and the potential MW contribution from CHP.

- *Estimate the growth of new facilities in the target market sectors.* The technical potential included economic projections for growth through 2020 by target market sectors in Texas. The growth factors used in the analysis for growth between the present and 2020 by individual sector are shown in **Table E-3**. Unless otherwise indicated, the growth rates represent the annualized 5-year (2000-2004) trend in GDP quantity growth indices by industry as reported by the Bureau of Economic Analysis. The BEA reports industries by NAICS which was mapped to the older SIC basis used by the market databases described above. Sectors that have been growing annually at greater than 5% per year are capped at 5% per year for the long-term growth estimate. Sectors that are declining are assumed to have zero growth during the forecast period. ACEEE provided growth rates for selected industries in the manufacturing sector; these growth rates were used as provided.

Two different types of CHP markets were included in the evaluation of technical potential. Both of these markets were evaluated for high and low load factor applications resulting in four distinct market segments that are analyzed. The markets, summarized in **Table E-4**, are described below:

- **Traditional CHP**—electric output is produced to meet all or a portion of the base load for a facility and the thermal energy is used to provide steam or hot water. Depending on the type of facility, the appropriate sizing could be either electric or thermal limited. Industrial facilities often have "excess" thermal load compared to their onsite electric load. Commercial facilities almost always have excess electric load compared to their thermal load. Two sub-categories were considered:
  - **High load factor applications**—This market provides for continuous or nearly continuous operation. It includes all industrial applications and round-the-clock commercial/institutional operations such colleges, hospitals, hotels, and prisons.
  - **Low load factor applications**—Some commercial and institutional markets provide an opportunity for coincident electric/thermal loads for a period of 3,500

to 5,000 hours per year. This sector includes applications such as office buildings, schools, and laundries.

- **Combined Cooling Heating and Power (CCHP) —**All or a portion of the thermal output of a CHP system can be converted to air conditioning or refrigeration with the addition of a thermally activated cooling system. This type of system can potentially open up the benefits of CHP to facilities that do not have the year-round thermal load to support a traditional CHP system. A typical system would provide the annual hot water load, a portion of the space heating load in the winter months and a portion of the cooling load in during the summer months. Two sub-categories were considered:
  - **Low load factor applications—**These represent markets that otherwise could not support CHP due to a lack of thermal load.
  - **Incremental high load factor applications—**These markets represent round-the-clock commercial/institutional facilities that could support traditional CHP, but with cooling, incremental capacity could be added while maintaining a high level of utilization of the thermal energy from the CHP system. All of the market segments in this category are also included in the high load factor traditional market segment, so only the incremental capacity for these markets is added to the overall totals.

Table E-1. Texas Technical Market Potential for CHP in Existing Facilities—Industrial Sector

SIC	Description	50-500 kW		500-1000 kW		1-5 MW		5-20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
20	Food	455	68	100	75	69	173	10	103	1	45	635	464
22	Textiles	65	7	12	7	2	4	2	14			81	31
24	Lumber and Wood	318	10	35	5	19	10	3	29			375	53
25	Furniture	24	1	1	0							25	1
26	Paper	171	26	93	70	41	103	1	8	3	266	309	472
27	Printing/Publishing	141	21	4	3	1	3					146	27
28	Chemicals	381	57	110	83	206	515	21	216	13	627	731	1,497
29	Petroleum Refining	165	25	36	27	6	15	7	87	10	1,817	224	1,971
30	Rubber/Misc Plastics	357	16	178	40	68	51	3	27			606	134
32	Stone/Clay/Glass	20	3	8	6	2	5					30	14
33	Primary Metals	57	2	32	6	22	14	1	17	2	87	114	126
34	Fabricated Metals	259	12	14	3	2	2	1	6			276	22
35	Machinery/Computer Equip	68	3	2	0	3	2	1	7			74	12
37	Trasportation Equip.	175	13	52	20	44	55	3	40			274	127
38	Instruments	21	2	2	1	2	3					25	5
39	Misc Manufacturing	50	2	7	1	3	2					60	5
	Total Industrial	2,727	267	686	347	490	953	53	553	29	2,842	3,985	4,962

Table E-2. Texas Technical Market Potential for CHP in Existing Facilities—Commercial and Institutional Sectors

SIC	Description	50-500 kW		500-1000 kW		1-5 MW		5-20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
4222, 5142	Warehouses	24	4									24	4
43	Post Offices	27	4									27	4
4581	Airports	4,252	319	1,701	638	425	531	77	481			6,455	1,969
4941, 4952	Water Treatment/Sanitary	1,350	101	489	183	76	95					1,915	380
52,53,56,57	Big Box Retail	234	35									234	35
5411, 5421, 5451, 5461, 5499	Food Sales	119	18									119	18
5812, 00, 01, 03, 05, 07, 08	Restaurants	114	17	6	5							120	22
6512	Office Buildings - Cooling	71	11	36	27	3	8					110	45
6513	Apartments	254	38	117	88	20	50					391	176
7011, 7041	Hotels	2,055	308	259	194	76	190					2,390	693
7211, 7213, 7218	Laundries	2,768	208	184	69	8	10					2,960	287
7542	Carwashes	2,236	168	15	6	1	1					2,252	175
7832	Movie Theaters	2,198	330	189	142	59	148					2,446	619
7991, 00, 01	Health Clubs	138	21	2	2							140	22
7992, 7997-9904, 7997-9906	Golf/Country Clubs	306	46	16	12							322	58
8051, 8052, 8059	Nursing Homes	458	69	22	17							480	85
8062, 8063, 8069	Hospitals	1,079	194	101	91	7	21					1,187	306
8211, 8243, 8249, 8299	Schools	261	47	210	189	173	519	3	45			647	800
8221, 8222	Colleges/Universities	829	31	171	32	6	4	1	3			1,007	70
8412	Museums	161	24	148	111	46	115	8	100			363	350
9223, 9211 (Courts), 9224 (firehouses)	Prisons	39	6	87	65	78	195	4	50			208	316
	Commercial, Institutional Totals	18,973	1,997	3,753	1,869	978	1,886	93	679			23,797	6,432

Table E-3. Target Market Sectors for CHP and Sector Growth Projections Through 2020

SIC	Industry Description	Texas Annual Growth Rate	Texas Growth 2007-2020
20	Food	2.50%	45%
22	Textiles	-5.41%	0%
24	Lumber and Wood	-2.29%	0%
25	Furniture	0.05%	1%
26	Paper	-4.53%	0%
27	Printing/Publishing	-5.24%	0%
28	Chemicals	2.93%	54%
29	Petroleum Refining	-1.00%	0%
30	Rubber/Misc Plastics	-2.30%	0%
32	Stone/Clay/Glass	2.32%	41%
33	Primary Metals	1.53%	26%
34	Fabricated Metals	-1.33%	0%
35	Machinery/Computer Equip	8.76%	110%
37	Trasportation Equip.	0.85%	14%
38	Instruments	1.90%	33%
39	Misc Manufacturing	4.20%	85%
4222, 5142	Warehouses	11.92%	110%
4941, 4952	Water Treatment/Sanitary	4.21%	86%
5411, 5421, 5451, 5461, 5499	Food Sales	4.53%	94%
5812, 00, 01, 03, 05, 07, 08	Restaurants	1.79%	31%
7011, 7041	Hotels	0.26%	4%
7211, 7213, 7218	Laundries	4.53%	94%
7542	Carwashes	4.53%	94%
7991, 00, 01	Health Clubs	2.54%	46%
7992, 7997-9904, 7997-9906	Golf/Country Clubs	2.54%	46%
8051, 8052, 8059	Nursing Homes	2.95%	55%
8062, 8063, 8069	Hospitals	2.95%	55%
8211, 8243, 8249, 8299	Schools	1.26%	21%
8221, 8222	Colleges/Universities	1.26%	21%
8412	Museums	3.60%	70%
9223, 9211 (Courts), 9224 (firehouses)	Prisons	1.83%	31%
6513	Apartments	0.57%	9%
43	Post Offices	0.30%	5%
4581	Airports	8.54%	110%
52,53,56,57	Big Box Retail	4.53%	94%
7832	Movie Theaters	2.99%	56%
7011, 7041	Hotels- Cooling	0.26%	4%
8051, 8052, 8059	Nursing Homes- Cooling	2.95%	55%
8062, 8063, 8069	Hospitals- Cooling	2.95%	55%
6512	Office Buildings - Cooling	0.57%	9%

Color Code
Long term growth capped at 5% per year
Declining Industry -- no growth
Growth specified by ACEEE

Table E-4. CHP Market Segments, Existing Facilities and Expected Growth 2007-2020

Market	50-500 kW MW	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total MW
Traditional High Load Factor Market						
Existing Facilities	895	1,161	1,976	740	2,842	7,615
New Facilities	187	287	578	228	382	1,663
Total	1,083	1,448	2,555	968	3,225	9,278
Traditional Low Load Factor Market						
Existing Facilities	219	67	4	3	0	292
New Facilities	93	18	0	0	0	111
Total	311	84	4	3	0	403
Cooling CHP High Load Factor Market (partially additive)						
Existing Facilities	571	422	688	45	0	1,725
New Facilities	109	119	227	23	0	476
Total	680	540	914	68	0	2,201
Cooling CHP Low Load Factor Market						
Existing Facilities	1,028	907	733	481	0	3,148
New Facilities	436	230	178	33	0	877
Total	1,464	1,137	911	514	0	4,025
Total Market including Incremental Cooling Load						
Existing Facilities	2,313	2,260	2,919	1,238	2,842	11,573
New Facilities	748	571	825	267	382	2,794
Total	3,061	2,831	3,744	1,505	3,225	14,366

Note: High load factor cooling market is comprised of a portion of the traditional high load factor market that has both heating and cooling loads. The total high load factor cooling market is shown, but only 30% of it is incremental to the portion already counted in the traditional high load factor market.

E.2. Energy Price Projections

The expected future relationship between purchased natural gas and electricity prices, called the *spark spread* in this context, is one major determinant of the ability of a facility with electric and thermal energy requirements to cost-effectively utilize CHP. For this screening analysis, a fairly simple methodology was used:

Electric Price Estimation

- Existing gas and electric price levels for the industrial market were taken from the EIA 2005 state average price of 7.14 cents/kWh.
- The future electric prices are based on the rate of change in the EIA early release 2007 Annual Energy Outlook estimate of average electric prices multiplied by the EIA 2005 Texas actual price. This price track is shown in **Table E-5**.
- Based on the average industrial price above, price differentials were estimated for the 5 CHP market size bins covered by the analysis. These price differentials are based on prior detailed utility rate analysis undertaken for a number of utilities in California and New York. The factors applied to the EIA average industrial price are as follows:
    - 50-500 kW—116%
    - 500-1000 kW—105%
    - 1-5 MW—100%
    - 5-20 MW—91%
    - >20 MW—91%
- Price adjustments for customer load factor were defined as follows:
    - High load factor—100% of the estimated value
    - Low load factor—120% of the estimated value
    - Peak cooling load—179% of the estimated value
- For a customer generating a portion of his own power with CHP, standby charges are estimated at 15% of the defined average electric rate. Therefore, when considering CHP, only 85% of a customer's rate can be avoided.

Natural Gas Price Estimation

- Current industrial natural gas price is defined from the EIA 2005 actual of $7.64/MMBtu.
- Wellhead gas real prices over the forecast period are based on the EIA 2007 Annual Energy Outlook as shown in **Table E-7.** This EIA forecast is very close to the price assumptions used by the Regional Greenhouse Gas Initiative.
- The wellhead gas prices were "marked up" to retail prices using first a city-gate adder of $0.20/MMBtu and then retail adders were included as follows:
    - 50-500 kW—$1.00/MMBtu for boiler fuel, $0.25/MMBtu for CHP fuel
    - 500-1000 kW—$0.40/MMBtu for boiler fuel, $0.25/MMBtu for CHP fuel
    - 1-5 MW—$0.40/MMBtu for boiler fuel, $0.25/MMBtu for CHP fuel
    - 5-20 MW—$0.25/MMBtu for both boiler fuel and CHP fuel
    - >20 MW—$0.25/MMBtu for both boiler fuel and CHP fuel.

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Table E-5. Input Price Forecast (EIA 2006d) and Texas Industrial Electric Price Estimation

Year	Wellhead Natural Gas	Average Retail Electricity		Texas Industrial Electricity
	$/MMBtu	$/MMBtu	$/kWh	$/kWh
2005	$7.29	$23.70	$0.0809	$0.0714
2006	$6.47	$24.38	$0.0832	$0.0735
2007	$6.45	$24.32	$0.0830	$0.0733
2008	$6.40	$24.30	$0.0829	$0.0732
2009	$5.88	$24.02	$0.0820	$0.0724
2010	$5.59	$23.66	$0.0808	$0.0713
2011	$5.17	$23.09	$0.0788	$0.0696
2012	$5.02	$22.80	$0.0778	$0.0687
2013	$4.87	$22.66	$0.0774	$0.0683
2014	$4.90	$22.55	$0.0769	$0.0679
2015	$4.84	$22.55	$0.0769	$0.0679
2016	$4.94	$22.69	$0.0774	$0.0684
2017	$5.13	$22.95	$0.0783	$0.0691
2018	$5.05	$23.14	$0.0790	$0.0697
2019	$4.99	$23.09	$0.0788	$0.0696
2020	$5.07	$23.15	$0.0790	$0.0698

E.3. CHP Technology Cost and Performance

The CHP system itself is the engine that drives the economic savings. The cost and performance characteristics of CHP systems determine the economics of meeting the site's electric and thermal loads. A representative sample of commercially and emerging CHP systems was selected to profile performance and cost characteristics in combined heat and power (CHP) applications. The selected systems range in capacity from approximately 100—20,000 kW. The technologies include gas-fired reciprocating engines, gas turbines, microturbines and fuel cells. The appropriate technologies were allowed to compete for market share in the penetration model. In the smaller market sizes, reciprocating engines competed with microturbines and fuel cells. In intermediate sizes (1 to 20 MW), reciprocating engines competed with gas turbines.

Cost and performance estimates for the CHP systems were based on work previously conducted for NYSERDA (Energy Nexus Group 2002), on peer-reviewed technology characterizations that EEA (2003) developed for the National Renewable Energy Laboratory (2003) and on follow-on work conducted by DE Solutions (2004) for Oak Ridge National Laboratory. Additional emissions characteristics and cost and performance estimates for emissions control technologies were based on ongoing work EEA (2003) is conducting for EPRI. (2003). Data is presented for a range of sizes that include basic electrical performance characteristics, CHP performance characteristics (power to heat ratio), equipment cost estimates, maintenance cost estimates, emission profiles with and without after-treatment control, and emissions control cost estimates. The technology characteristics are presented for three years: 2005, 2010, 2020. The 2005 estimates are based on current commercially available and emerging technologies. The cost and performance estimates for 2010 and 2020 reflect current technology development paths and currently planned government and industry funding. These projections were based on estimates included in the three references mentioned above. NOx, CO and VOC emissions estimates in lb/MWh are presented for each technology both with and without aftertreatment control (AT). NOx emissions are presented with and without a CHP thermal credit (using a displaced emissions approach and displaced boiler emissions of 0.2 lb/MMBtu for all technologies). Which system is applicable in any size category (e.g., with aftertreatment or without) is a function of the specific emissions requirements assumptions for each scenario. The installed costs in the following technology performance summary tables are based on typical national averages.

Table E-6. Reciprocating Engines

Size and Type	Characterization	2005	2012	2020
100 kW Rich Burn	Capacity, kW	100	100	100
	Installed Costs, $/kW	1,550	1,350	1,100
w/three way catalyst	Heat Rate, Btu/kWh	11,500	10,830	10,500
	Electric Efficiency, %	29.7%	31.5%	32.5%
	Power to Heat Ratio	0.61	0.67	0.7
	Thermal Output, Btu/kWh	5593	5093	4874
	O&M Costs, $/kWh	0.018	0.013	0.012
	NOx Emissions, lbs/MWh (no AT)	40	40	40
	NOx Emissions, lbs/MWh (w/ AT)	0.5	0.25	0.2
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	N/A	N/A	N/A
	CO Emissions, gm/bhp-hr	13.00	10.00	10.00
	CO Emissions w/AT, lb/MWh	1.87	0.60	0.30
	VOC Emissions w/AT, lb/MWh	0.47	0.09	0.05
	PMT 10 Emissions, lb/MWh	0.11	0.11	0.11
	SO2 Emissions, lb/MWh	0.0068	0.0064	0.0062
	AT Cost, $/kW	N/A	N/A	N/A
300 kW Rich Burn	Capacity, kW	300	300	300
	Installed Costs, $/kW	1,250	1,150	1,050
w/three way catalyst	Heat Rate, Btu/kWh	11,500	10,830	10,500
	Electric Efficiency, %	29.7%	31.5%	32.5%
	Power to Heat Ratio	0.61	0.67	0.7
	Thermal Output, Btu/kWh	5593	5093	4874
	O&M Costs, $/kWh	0.013	0.012	0.01
	NOx Emissions, lbs/MWh (no AT)	40	40	40
	NOx Emissions, lbs/MWh (w/ AT)	0.5	0.25	0.2
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	N/A	N/A	N/A
	CO Emissions, gm/bhp-hr	13.00	10.00	10.00
	CO Emissions, gm/bhp-hr	13	10	10
	CO Emissions w/AT, lb/MWh	1.87	0.60	0.30
	VOC Emissions w/AT, lb/MWh	0.47	0.09	0.05
	PMT 10 Emissions, lb/MWh	0.10	0.10	0.10
	SO2 Emissions, lb/MWh	0.0068	0.0064	0.0062
	AT Cost, $/kW	50	50	45
800 kW Lean Burn	Capacity, kW	800	800	800
	Installed Costs, $/kW	1,200	1,100	950
	Heat Rate, Btu/kWh	10,650	9,750	9,225
AT is SCR	Electric Efficiency, %	32.0%	35.0%	37.0%
	Power to Heat Ratio	0.8	0.9	1.05
% NOx reduction w/AT	Thermal Output, Btu/kWh	4265	3791	3250
2005 - 40%	O&M Costs, $/kWh	0.012	0.01	0.009
2010 - 30%	NOx Emissions, gm/bhphr	0.8	0.4	0.3
2020 - 40%	NOx Emissions, lbs/MWh (no AT)	2.48	1.24	0.93
	NOx Emissions, lbs/MWh (no AT; w/CHP)	1.41	0.29	0.12
	NOx Emissions, lbs/MWh (w/ AT)	1.49	0.87	0.56
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	N/A	N/A	N/A
	CO Emissions, gm/bhp-hr	3	2.5	2
	CO Emissions w/AT, lb/MWh	0.87	0.45	0.31
	VOC Emissions w/AT, lb/MWh	0.38	0.05	0.05
	PMT 10 Emissions, lb/MWh	0.01	0.01	0.01
	SO2 Emissions, lb/MWh	0.0063	0.0057	0.0054
	AT Cost, $/kW	300	190	140
3,000 kW Lean Burn	Capacity, kW	3000	3000	3000
	Installed Costs, $/kW	950	925	875
	Heat Rate, Btu/kWh	9,700	8,750	8,325
AT is SCR	Electric Efficiency, %	35.2%	39.0%	41.0%
	Power to Heat Ratio	1.04	1.07	1.18
% NOx reduction w/AT	Thermal Output, Btu/kWh	3281	3189	2892
2005 - 30%	O&M Costs, $/kWh	0.0085	0.0083	0.008
2010 - 30%	NOx Emissions, gm/bhphr	0.7	0.4	0.25
2020 - 30%	NOx Emissions, lbs/MWh (no AT)	2.17	1.24	0.775
	NOx Emissions, lbs/MWh (no AT; w/CHP)	1.35	0.44	0.05
	NOx Emissions, lbs/MWh (w/ AT)	1.52	0.87	0.53
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	N/A	N/A	N/A
	CO Emissions, gm/bhp-hr	2.5	2	2
	CO Emissions w/AT, lb/MWh	0.78	0.31	0.31
	VOC Emissions w/AT, lb/MWh	0.34	0.10	0.10
	PMT 10 Emissions, lb/MWh	0.01	0.01	0.01
	SO2 Emissions, lb/MWh	0.0057	0.0051	0.0049
	AT Cost, $/kW	200	130	100
5,000 kW Lean Burn	Capacity, kW	5000	5000	5000
	Installed Costs, $/kW	925	900	850
	Heat Rate, Btu/kWh	9,213	8,325	7,935
AT is SCR	Electric Efficiency, %	37.0%	41.0%	43.0%
	Power to Heat Ratio	1.02	1.22	1.31
% NOx reduction w/AT	Thermal Output, Btu/kWh	3345	2797	2605
2005 - 20%	O&M Costs, $/kWh	0.008	0.008	0.008
2010 - 30%	NOx Emissions, gm/bhphr	0.5	0.4	0.25
2020 - 30%	NOx Emissions, lbs/MWh (no AT)	1.55	1.24	0.775
	NOx Emissions, lbs/MWh (no AT; w/CHP)	0.71	0.54	0.12
	NOx Emissions, lbs/MWh (w/ AT)	1.24	0.87	0.54
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	N/A	N/A	N/A
	CO Emissions, gm/bhp-hr	2.5	2	2
	CO Emissions w/AT, lb/MWh	0.75	0.31	0.31
	VOC Emissions w/AT, lb/MWh	0.22	0.1	0.1
	PMT 10 Emissions, lb/MWh	0.01	0.01	0.01
	SO2 Emissions, lb/MWh	0.0054	0.0049	0.0047
	AT Cost, $/kW	150	115	80

CHP thermal credit based on Displaced Boiler Emissions = 0.2 lbs/MMBtu
AT = Aftertreament

Additional O&M Costs for SCR

	2005	2012	2020	
800 kW Lean Burn	0.005	0.003	0.002	SCR Adder, $/kWh
	0.017	0.013	0.011	New total O&M w/SCR, $/kWh
3,000 kW Lean Burn	0.003	0.002	0.002	SCR Adder, $/kWh
	0.011	0.011	0.010	New total O&M w/SCR, $/kWh
5,000 kW Lean Burn	0.002	0.002	0.001	SCR Adder, $/kWh
	0.010	0.010	0.009	New total O&M w/SCR, $/kWh

Size and Type	Characterization	2005	2012	2020
1 MW Gas Turbine	Capacity, MW	1	1	1
	Installed Costs, $/kW	1,900	1,500	1,300
	Heat Rate, Btu/kWh	15,580	14,500	13,500
AT is SCR	Electric Efficiency, %	21.9%	23.5%	25.3%
	Power to Heat Ratio	0.51	0.61	0.7
	Thermal Output, Btu/kWh	6690	5593	4874
	O&M Costs, $/kWh	0.01	0.013	0.012
	NOx Emissions, ppm	42.0	15.0	9.0
	NOx Emissions, lbs/MWh (no AT)	2.2	0.7	0.4
	NOx Emissions, lbs/MWh (no AT; w/CHP)	0.53	-0.70	-0.82
	NOx Emissions, lbs/MWh (w/ AT)	0.22	0.07	0.04
	CO Emissions, ppm	6	20	20
	CO Emissions, lb/MWh	0.027	0.6	0.56
	VOC Emissions, lb/MWh	0.027	0.025	0.023
	PMT 10 Emissions, lb/MWh	0.32	0.30	0.28
	SO2 Emissions, lb/MWh	0.0092	0.0085	0.0079
	AT Cost, $/kW	300	250	150
3 MW Gas Turbine	Capacity, MW	3	3	3
	Installed Costs, $/kW	1,300	1,200	1,000
	Heat Rate, Btu/kWh	13,100	12,650	11,200
	Electric Efficiency, %	26.0%	27.0%	30.5%
AT is SCR	Power to Heat Ratio	0.68	0.76	0.84
	Thermal Output, Btu/kWh	5018	4489	4062
	O&M Costs, $/kWh	0.006	0.005	0.005
	NOx Emissions, ppm	15.0	9.0	5.0
	NOx Emissions, lbs/MWh (no AT)	0.68	0.38	0.2
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-0.57	-0.74	-0.82
	NOx Emissions, lbs/MWh (w/ AT)	0.068	0.038	0.02
	CO Emissions, ppm	20	20	20
	CO Emissions, lb/MWh	0.55	0.53	0.47
	VOC Emissions, lb/MWh	0.027	0.025	0.023
	PMT 10 Emissions, lb/MWh	0.21	0.20	0.18
	SO2 Emissions, lb/MWh	0.007	0.0069	0.0069
	AT Cost, $/kW	210	175	150
5 MW Gas Turbine	Capacity, MW	5	5	5
	Installed Costs, $/kW	1,100	1,000	950
	Heat Rate, Btu/kWh	12,590	11,375	10,500
	Electric Efficiency, %	27.1%	30.0%	32.5%
AT is SCR	Power to Heat Ratio	0.68	0.76	0.84
	Thermal Output, Btu/kWh	5018	4489	4062
	O&M Costs, $/kWh	0.006	0.005	0.005
	NOx Emissions, ppm	15.0	9.0	5.0
	NOx Emissions, lbs/MWh (no AT)	0.68	0.38	0.2
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-0.57	-0.74	-0.82
	NOx Emissions, lbs/MWh (w/ AT)	0.068	0.038	0.02
	AT Cost, $/kW	210	175	150
10 MW Gas Turbine	Capacity, MW	10	10	10
	Installed Costs, $/kW	965	950	850
	Heat Rate, Btu/kWh	11,765	10,800	9,950
	Electric Efficiency, %	29.0%	31.6%	34.3%
AT is SCR	Power to Heat Ratio	0.73	0.84	0.94
	Thermal Output, Btu/kWh	4674	4062	3630
	O&M Costs, $/kWh	0.006	0.005	0.005
	NOx Emissions, ppm	15.0	9.0	5.0
	NOx Emissions, lbs/MWh (no AT)	0.67	0.37	0.2
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-0.50	-0.65	-0.71
	NOx Emissions, lbs/MWh (w/ AT)	0.067	0.037	0.02
	CO Emissions, ppm	20	20	20
	CO Emissions, lb/MWh	0.5	0.46	0.42
	VOC Emissions, lb/MWh	0.022	0.021	0.02
	PMT 10 Emissions, lb/MWh	0.2	0.18	0.17
	SO2 Emissions, lb/MWh	0.0069	0.0064	0.0059
	AT Cost, $/kW	140	125	100
25 MW Gas Turbine	Capacity, MW	25	25	25
	Installed Costs, $/kW	800	755	725
	Heat Rate, Btu/kWh	9,945	9,225	8,865
	Electric Efficiency, %	34.3%	37.0%	38.5%
AT is SCR	Power to Heat Ratio	0.95	1.04	1.1
	Thermal Output, Btu/kWh	3592	3281	3102
	O&M Costs, $/kWh	0.005	0.005	0.004
	NOx Emissions, ppm	15.0	5.0	3.0
	NOx Emissions, lbs/MWh (no AT)	0.6	0.2	0.1
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-0.30	-0.62	-0.68
	NOx Emissions, lbs/MWh (w/ AT)	0.06	0.02	0.01
	CO Emissions, ppm	20	20	20
	CO Emissions w/AT, lb/MWh	0.05	0.05	0.04
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.17	0.16	0.15
	SO2 Emissions, lb/MWh	0.0058	0.0054	0.0052
	AT Cost, $/kW	100	80	50
40 MW Gas Turbine	Capacity, MW	40	40	40
	Installed Costs, $/kW	700	680	660
	Heat Rate, Btu/kWh	9,220	8,865	8,595
	Electric Efficiency, %	37.0%	38.5%	39.7%
AT is SCR	Power to Heat Ratio	1.07	1.13	1.18
	Thermal Output, Btu/kWh	3189	3019	2892
	O&M Costs, $/kWh	0.004	0.004	0.004
	NOx Emissions, ppm	15.0	5.0	3.0
	NOx Emissions, lbs/MWh (no AT)	0.55	0.2	0.1
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-0.25	-0.55	-0.62
	NOx Emissions, lbs/MWh (w/ AT)	0.055	0.02	0.01
	CO Emissions, ppm	20	20	20
	CO Emissions w/AT, lb/MWh	0.04	0.04	0.04
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.157	0.15	0.15
	SO2 Emissions, lb/MWh	0.0054	0.0052	0.0051
	AT Cost, $/kW	90	75	40

CHP Thermal credit based on Displaced Boiler Emissions = 0.2 lbs/MMBtu
AT = Aftertreatment

Table E-7. Microturbines

Size and Type	Characterization	2005	2012	2020
70-100 kW	Capacity, kW	70	70	70
	Installed Costs, $/kW	2,200	1,800	1,400
	Heat Rate, Btu/kWh	13,500	12,500	11,375
	Electric Efficiency, %	25.3%	27.3%	30.0%
	Power to Heat Ratio	0.7	0.9	1.1
	Thermal Output, Btu/kWh	4874	3791	3102
	O&M Costs, $/kWh	0.017	0.016	0.012
	NOx Emissions, ppm	3.0	3.0	3.0
	NOx Emissions, lbs/MWh (no AT)	0.15	0.14	0.13
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-1.07	-0.81	-0.65
	NOx Emissions, lbs/MWh (w/ AT)	N/A	N/A	N/A
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	N/A	N/A	N/A
	CO Emissions, ppm	8	8	8
	CO Emissions, lb/MWh	0.24	0.22	0.20
	VOC Emissions, lb/MWh	0.027	0.025	0.023
	PMT 10 Emissions, lb/MWh	0.22	0.20	0.19
	SO2 Emissions, lb/MWh	0.0079	0.0074	0.0067
	AT Cost, $/kW	N/A	N/A	N/A
250 kW	Capacity, kW	250	250	250
	Installed Costs, $/kW	2,000	1,600	1,200
	Heat Rate, Btu/kWh	11,850	11,750	10,825
	Electric Efficiency, %	28.8%	29.0%	31.5%
	Power to Heat Ratio	0.94	1	1.3
	Thermal Output, Btu/kWh	3630	3412	2625
	O&M Costs, $/kWh	0.016	0.015	0.012
	NOx Emissions, ppm	9.0	5.0	3.0
	NOx Emissions, lbs/MWh (no AT)	0.43	0.24	0.13
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-0.48	-0.62	-0.53
	NOx Emissions, lbs/MWh (w/ AT)	N/A	N/A	N/A
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	N/A	N/A	N/A
	CO Emissions, ppm	9	9	9
	CO Emissions, lb/MWh	0.26	0.26	0.24
	VOC Emissions, lb/MWh	0.027	0.025	0.023
	PMT 10 Emissions, lb/MWh	0.18	0.18	0.16
	SO2 Emissions, lb/MWh	0.0070	0.0069	0.0064
	AT Cost, $/kW	500	200	90
500 kW	Capacity, kW	-	500	500
	Installed Costs, $/kW	-	1,150	900
	Heat Rate, Btu/kWh	-	10,350	9,750
	Electric Efficiency, %	-	33.0%	35.0%
	Power to Heat Ratio	-	1.3	1.38
	Thermal Output, Btu/kWh	-	2625	2472
	O&M Costs, $/kWh	-	0.015	0.012
	NOx Emissions, ppm	-	5.0	3.0
	NOx Emissions, lbs/MWh (no AT)	-	0.2	0.11
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-	-0.46	-0.51
	NOx Emissions, lbs/MWh (w/ AT)	-	N/A	N/A
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	-	N/A	N/A
	CO Emissions, ppm	-	9	9
	CO Emissions, lb/MWh	-	0.24	0.23
	VOC Emissions, lb/MWh	-	0.025	0.023
	PMT 10 Emissions, lb/MWh		0.0061	0.0057
	SO2 Emissions, lb/MWh	-	0.0056	0.0053
	AT Cost, $/kW	-	200	90

CHP thermal credit based on Displaced Boiler Emissions = 0.2 lbs/MMBtu
AT = Aftertreament

Table E-8. Fuel Cells

Size and Type	Characterization	2005	2012	2020
150 kW PEMFC	Capacity, kW	150	150	150
	Installed Costs, $/kW	3,800	3,600	2,700
	Heat Rate, Btu/kWh	9,750	9,480	8,980
	Electric Efficiency, %	35.0%	36.0%	38.0%
	Power to Heat Ratio	0.95	0.98	1.04
	Thermal Output, Btu/kWh	3592	3482	3281
	O&M Costs, $/kWh	0.023	0.017	0.015
	NOx Emissions, ppm			
	NOx Emissions, lbs/MWh (no AT)	0.10	0.07	0.05
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-0.80	-0.80	-0.77
	CO Emissions, ppm	-	-	-
	CO Emissions, lb/MWh	0.07	0.07	0.07
	VOC Emissions, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.001	0.001	0.001
	SO2 Emissions, lb/MWh	0.0057	0.0056	0.0053
250 kW MCFC/SOFC	Capacity, kW	250	250	250
	Installed Costs, $/kW	5,000	3,200	2,500
	Heat Rate, Btu/kWh	7,930	7,125	6,920
	Electric Efficiency, %	43.0%	47.9%	49.3%
	Power to Heat Ratio	1.95	1.98	2.13
	Thermal Output, Btu/kWh	1750	1723	1602
	O&M Costs, $/kWh	0.032	0.02	0.015
	NOx Emissions, ppm			
	NOx Emissions, lbs/MWh (no AT)	0.06	0.05	0.04
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-0.38	-0.38	-0.36
	NOx Emissions, lbs/MWh (w/ AT)			
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)			
	CO Emissions, ppm	-	-	-
	CO Emissions, lb/MWh	0.06	0.05	0.04
	VOC Emissions, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.001	0.001	0.001
	SO2 Emissions, lb/MWh	0.0047	0.0042	0.0041
2 MW MCFC	Capacity, kW	2,000	2000	2000
	Installed Costs, $/kW	3,250	2,800	2,200
	Heat Rate, Btu/kWh	7,420	7,110	6,820
	Electric Efficiency, %	46.0%	48.0%	50.0%
	Power to Heat Ratio	1.92	2	2.27
	Thermal Output, Btu/kWh	1777	1706	1503
	O&M Costs, $/kWh	0.033	0.019	0.015
	NOx Emissions, ppm			
	NOx Emissions, lbs/MWh (no AT)	0.05	0.05	0.04
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-0.39	-0.38	-0.34
	NOx Emissions, lbs/MWh (w/ AT)			
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)			
	CO Emissions, ppm	-	-	-
	CO Emissions, lb/MWh	0.04	0.04	0.03
	VOC Emissions, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.001	0.001	0.001
	SO2 Emissions, lb/MWh	0.0044	0.0042	0.0040

CHP thermal credit based on Displaced Boiler Emissions = 0.2 lbs/MMBtu
AT = Aftertreament

E.4. Market Penetration Analysis

EEA has developed a CHP market penetration model that estimates cumulative CHP market penetration in 5-year increments. For this analysis, the forecast periods are 2010, 2015, and 2020. The target market is comprised of the facilities that make up the technical market potential as defined in Appendix E.1. The economic competition module in the market penetration model compares CHP technologies (Appendix E.3) to purchased fuel and power (Appendix E.2) in 5 different sizes and 4 different CHP application types. The calculated payback determines the potential pool of customers that would consider accepting the CHP investment as economic. Additional, non economic screening factors are applied that limit the pool of customers that can accept CHP in any given market/size. Based on this calculated economic potential, a market diffusion model is used to determine the cumulative market penetration for each 5-year time period. The basic outputs of the model are shown in **Table E-9** as follows:

Technical potential represents the total capacity potential from existing and new facilities that are likely to have the appropriate physical electric and thermal load characteristics that would support a CHP system with high levels of thermal utilization during business operating hours.

Economic potential, as shown in the table, reflects the share of the technical potential capacity (and associated number of customers) that would consider the CHP investment economically acceptable according to a procedure that is described in more detail below.

Cumulative market penetration represents an estimate of CHP capacity that will actually enter the market between 2006 and 2020. This value discounts the economic potential to reflect non-economic screening factors and the rate that CHP is likely to actually enter the market.

Table E-9. Summary CHP Market Values for Texas: Technical Potential, Economic Potential, Cumulative 2006-2020 Market Penetration

	50-500 kW (MW)	500 kW -1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total MW
Technical Potential	3,411	3,021	3,830	1,431	2,842	14,534
Economic Potential	406	358	764	310	1,057	2,896
Cumulative 2006-2020 Market Penetration	50	49	165	100	538	902

In addition to segmenting the market by size, as shown in the table, the analysis is conducted in four separate CHP market applications (high load and low load factor traditional CHP and high and low load factor CHP with cooling.) These markets are considered individually because both the annual load factor and the installation and operation of thermally activated cooling has an impact on the system economics.

Economic potential is determined by an evaluation of the competitiveness of CHP versus purchased fuel and electricity. The projected future fuel and electricity prices and the cost and performance of CHP technologies determine the economic competitiveness of CHP in each market. CHP technology and performance assumptions appropriate to each size category and region were selected to represent the competition in that size range (**Table E-10)**. Additional assumptions were made for the competitive analysis. Technologies below 1 MW in electrical capacity are assumed to have an economic life of 10 years. Larger systems are assumed to have an economic life of 15 years. Capital related amortization costs were based on a 10% discount rate. Based on their operating characteristics (each category and each size bin within the category have specific assumptions about the annual hours of CHP operation (80-90% for the high load factor cases with appropriate adjustments for low load factor facilities), the share of recoverable thermal energy that gets utilized (80%-90%), and the share of useful thermal energy that is used for cooling compared to traditional heating. The economic figure-of-merit chosen to reflect this competition in the market penetration model is simple payback.[25] While not the most sophisticated measure of a project's performance, it is nevertheless widely understood by all classes of customers.

Table E-10. Technology Competition Assumed within Each Size Category

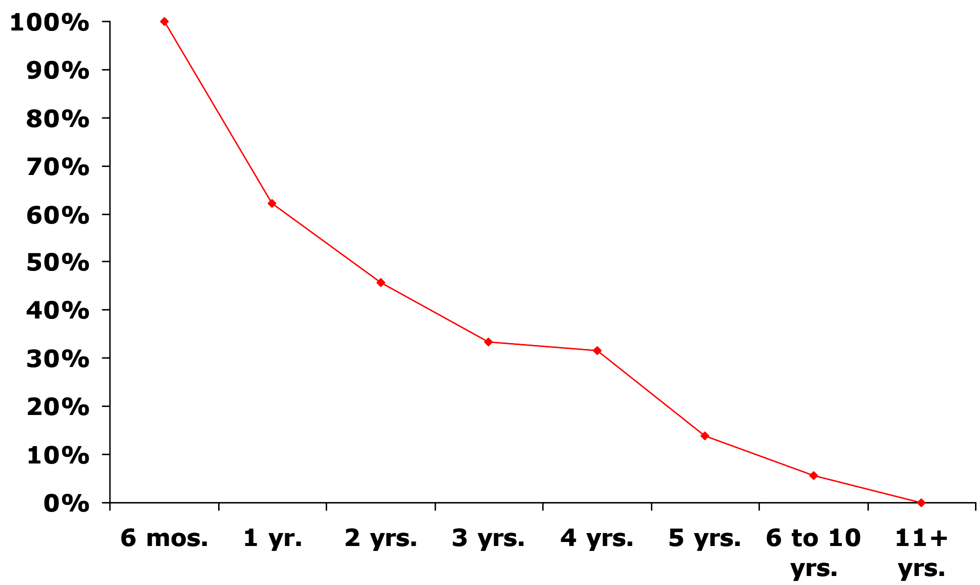
Market Size Bins	*Competing Technologies*
50 - 500 kW	100 kW Recip Engine
	70 kW Microturbine
	150 kW PEM Fuel Cell
500 - 1,000 kW	300 kW Recip Engine (multiple units)
	70 kW Microturbine (multiple units)
	250 kW MC/SO Fuel Cell (multiple units)
1 - 5 MW	3 MW Recip Engine
	3 MW Gas Turbine
	2 MW MC Fuel Cell
5 - 20 MW	5 MW Recip Engine
	5 MW Gas Turbine
20 - 100 MW	40 MW Gas Turbine

Rather than use a single payback value, such as 3 years or 5 years as the determinant of economic potential, we have based the market acceptance rate on a survey of commercial and industrial facility operators concerning the payback required for them to consider installing CHP. **Figure E-1** shows the percentage of survey respondents that would accept CHP investments at different payback levels (CEC 2005). As can be seen from the figure, more than 30% of customers would reject a project that promised to return their initial investment in just one year. A little more than half would reject a project with a payback of 2 years. This type of payback translates into a project with an ROI of 49% to 100%. Potential

[25] Simple payback is the number of years that it takes for the annual operating savings to repay the initial capital investment.

explanations for rejecting a project with such high returns is that the average customer does not believe that the results are real and is protecting himself from this perceived risk by requiring very high projected returns before a project would be accepted, or that the facility is very capital limited and is rationing its capital raising capability for higher priority projects (market expansion, product improvement, etc.).

Figure E-1. Customer Payback Acceptance Curve



Source: *Primen's 2003 Distributed Energy Market Survey*

For each market segment, the economic potential represents the technical potential multiplied by the share of customers that would accept the payback calculated in the economic competition module.

The estimation of market penetration includes both a non-economic screening factor and a factor that estimates the rate of market penetration (diffusion.) The non-economic screening factor was applied to reflect the share of each market size category (i.e., applications of 50 to 500 kW, applications of 500 to 1,000 kW, etc) within the economic potential that would be willing and able to consider CHP at all. These factors range from 32% in the smallest size bin (50-500 kW) to 64% in the largest size bin (more than 20 MW.) These factors are intended to take the place of a much more detailed screening that would eliminate customers that do not actually have appropriate electric and thermal loads in spite of being within the target markets, do not use gas or have access to gas, do not have the space to install a system, do not have the capital or credit worthiness to consider investment, or are otherwise unaware, indifferent, or hostile to the idea of adding CHP. The specific value for each size bin was established based on an evaluation of EIA facility survey data and gas use statistics from the iMarket database.

The rate of market penetration is based on a *Bass diffusion curve* with allowance for growth in the maximum market. This function determines cumulative market penetration for each 5-year period. Smaller size systems are assumed to take a longer time to reach maximum market penetration than larger systems. Cumulative market penetration using a Bass diffusion curve takes a typical S-shaped curve. In the generalized form used in this analysis, growth in the number of ultimate adopters is allowed. The curves shape is determined by an initial market penetration estimate, growth rate of the technical market potential, and two factors described as *internal market influence* and *external market influence*.

The cumulative market penetration factors reflect the economic potential multiplied by the non-economic screening factor (maximum market potential) and by the Bass model market cumulative market penetration estimate.

Once the market penetration is determined, the competing technology shares within a size/utility bin are based on a *logit function* calculated on the comparison of the system paybacks. The greatest market share goes to the lowest cost technology, but more expensive technologies receive some market share depending on how close they are to the technology with the lowest payback. (This technology allocation feature is part of the EEA CHP model that is not specifically used for this analysis.)

APPENDIX F: ONSITE RENEWABLES

F.1. Introduction

This appendix provides background on existing renewable energy installations in Texas and describes the impressive success of Germany's renewable energy development efforts. An incentive approach to accelerate bringing onsite renewable generation to market in Texas is also described.

Status of Renewable Energy in Texas:

Renewable energy policies enacted since 1999 have been extraordinarily successful in stimulating rapid development of wind power. Prior to 1999, Texas had 42 MW of wind. Eight years later there are 2,768 MW operational and another 1,000 MW currently in advanced stages of construction (as of January 1, 2007). Secondarily, landfill gas has enjoyed some success in Texas. Other than wind power and landfill gas, the Texas story is one of unrealized potential. With focused attention, however, there are many other renewable energy resources that are in the range of being "cost effective".

Table F-1. Renewable Energy Capacity in the Texas REC Program (Feb. 22, 2007)

Technology	Existing Renewable Energy Capacity Texas(MW)	New Renewable Energy Capacity Texas(MW)	Existing Renewable Energy Capacity Non-Texas(MW)	New Renewable Energy Capacity Non-Texas(MW)
Biomass	0.0	12.2	0.0	0.0
Hydro	203.0	10.3	0.0	0.0
Landfill gas	6.3	54.3	0.0	0.0
Solar	0.0	1.2	0.0	0.0
Wind	115.8	2,929.0	0.0	0.0

Source: http://www.texasrenewables.com/publicReports/.

Table F-2. Renewable Energy Generation in Texas (MWh) by Technology Type

Technology	Year	Quarter1	Quarter2	Quarter3	Quarter4	Total (MWh)
Biomass	2006	16,327	10,479	17,152	16,610	60,569
Hydro	2006	55,000	83,064	44,870	27,143	210,077
Landfill gas	2006	69,191	78,650	75,665	82,580	306,087
Solar	2006	26	43	41	26	136
Wind	2006	1,478,927	1,584,166	1,376,540	2,091,295	6,530,928
Grand Totals		1,619,471	1,756,403	1,514,268	2,217,654	7,107,797

Source: http://www.texasrenewables.com/publicReports/.

As a general rule, as renewable energy technologies mature, they will increasingly penetrate the market and deliver environmental and cost benefits to consumers. This derives from the historical fact that renewable energy costs are trending downward, while conventional energy and environmental compliance costs are trending upward. When considered through a life-cycle cost assessment, new renewables will be more cost effective than conventional energy sources well in advance of the time the current-year prices of renewable and conventional technology achieve parity. On the other hand, the reality of market inertia will delay significantly the rate at which new technology and market options are adopted, even when the new options are clearly superior. Incentives are an appropriate public policy endeavor to hasten the transition toward energy options that can provide societal and consumer economic and health benefits.

A recent demonstration of market inertia is the level of customer switching during the transition period (2002-2006) of Texas' competitive retail electric market. Even with very strong "Price-to-Beat" incentives to encourage residential electric consumers to switch electric providers (where many consumers could have reduced their electricity costs by 16 to 31% or more), only about 34% of residential customers did switch, at a typical rate of about 7% per year.[26] The Texas transition period experience also highlighted that sophisticated large industrial and commercial consumers are much more likely than residential consumers to take advantage of opportunities to lower electric costs. Lessons learned through Texas' transition to competition suggest that the low-hanging fruit for stimulating onsite renewables is likewise more likely to come from large industrial and commercial actions than through the choices of individual homeowners.

What is Possible in Texas?

This section explores the potential for onsite renewable energy in Texas, based on consideration of leading-edge international programs in Germany framed in the context of market barriers in Texas.

Model of Success: Germany, a country with modest solar and wind resources but one that is strongly committed to investments in environmental protection, has been the most effective market globally in promoting a broad range of renewable energy technologies. A summary of Germany's progress in renewable energy production between the years 1990-2005 and corresponding 5-year growth rates by technology are provided in Table F-3 below.

Table F-3. Renewable Energy Production in Germany (GWh)

	Wind	Biomass	PV	SWH
1990	40	1,422	1	130
1995	1,800	2,020	11	440
2000	7,550	4,129	64	1,279
2005	26,500	13,444	1,000	2,960

Source: Saiss et al. 2006

[26] PUCT, Scope of Competition in Electric Markets in Texas. 2007, pages 59-65.

Table F-4. Average Annual Growth Rate, Previous 5 year Period

	Wind	Biomass	PV	SWH
1990	-	-	-	-
1995	115%	7%	62%	28%
2000	33%	15%	42%	24%
2005	28%	27%	73%	18%

Source: Saiss et al. 2006

Renewable energy now produces more than 10% of Germany's electricity. These results stem from a major commitment to effective incentives, with a commensurate commitment to funding. Germany's diversified renewable energy programs in 2005 resulted in $9 billion in construction of new plants, $7.4 billion in operation of plants, and accounted for 170,000 jobs (Saiss et al. 2006).

Germany, with a peak demand that is approximately 10% greater than Texas, is now projected to have exceeded 20,000 MW of installed wind capacity, distributed in very small projects, often on the order of 1 MW in size. Germany's success has been driven by attractive "feed-in law" incentives, which are guaranteed buy-back rates from the local utility. Since Texas has nearly twice the land area of Germany and offers wind regimes that are far better than Germany's, appropriate incentives offered in Texas would likely replicate Germany's success. Stimulus in Texas would be timely, as many industrial electric consumers are currently evaluating on site wind power to defray high purchased energy costs. Even Texas' largest oil producer, Occidental, reported in December 2006 that it was evaluating wind power as an onsite energy option.

<u>Challenges:</u> The abundant, high-quality renewable resources in Texas coupled with a can-do, business-friendly culture suggest extraordinary success awaits if the state commits to building a road to success. However, onsite generation especially when not based on fossil fuels, is far different from the norm and must overcome three long-entrenched challenges:

1. A system fundamentally based on centralized electricity supply will generally resist the emergence of almost any level of distributed generation owned by customers;
2. Major risk factors of energy suppliers, such as fuel price volatility and compliance with future environmental regulations, are often easily passed on to consumers (e.g. automatic fuel cost adjustments, deferring consideration of the environmental ramifications of generation decisions); and
3. The Status Quo market is remarkably durable—irrespective of actual cost impacts to consumers—whereas virtually any new energy approach—even those with broad popular support—will likely be attacked and labeled as "too expensive" by status quo stakeholder interests.

These issues can be summarized in the following: *Will Texas actively support and encourage the choice of individual consumers to produce a portion of their own power?* While the answer remains to be seen, Texas may be better positioned to succeed than any other state in the country. Texas' competitive wholesale market structure largely dismantles the first two challenges identified above, since generators are responsible for their own fuel and environmental costs and have multiple options to sell their output, including a significant and viable balancing energy market. Likewise for retail customers, there are far more options of supply, which logically could include some degree of self-generation. With many of the market fundamentals starting to come into place, perhaps the biggest question for Texas is whether it will succeed in authorizing near-term investment in incentives to kick-start the onsite renewable generation market and expand money-saving efficiency programs.

Overarching threshold issues

Cost Effectiveness: Texas is a diverse electric market with more options available to consumers than in most other states. Traditional measures of "cost-effectiveness" are not as relevant in a market based on "value" rather than based on "cost".

The baseline assumptions electric rate assumptions throughout this report—for both efficiency and renewable measures—reflect prices that are much lower and more stable than what has been observed in recent years Texas market. Table F-5 shows the current spectrum of rates in the competitive electric market for representative areas of the state.

Examination of competitive offerings in Texas reflects a premium for environmentally superior products (such as those based on renewable energy) and indicates that predictability also commands a premium (fixed rates are generally higher than adjustable rate offerings.)

Table F-5. Residential Electric Rates in Texas

	Dallas	Houston	West TX (Sonora)
High	16	16.2	17.8
Incumbent	14.5	15.4	15.4
Median	13.1	13.5	13.7
Low	10.4	10.8	9.4

NOTES: Incumbent rate shown for Dallas = TXU Texas Choice Plan; Houston = Reliant Basic Flex Plan; Sonora = WTU Direct Electricity Plan. All rates taken from "Power to Choose" website (http://www.powertochoose.org/).

Emission Reductions from Renewables

Ozone is generally considered to be the pollutant of greatest concern in Texas. Reductions of nitrous oxides (NOx) stemming from different state energy efficiency and renewable energy programs are shown in Table F-6. These projections for 2009 are from the Energy Systems Laboratory at Texas A&M University in 2006. Note that wind being installed to satisfy the Texas RPS has the greatest NOx reduction impact of all state efficiency and renewable energy programs.

Table F-6. Total Cumulative NO_X Reductions in 2009

	Tons/Year	Tons/Peak-OSD
Energy Efficiency	900.52	4.47
PUC SB7 & SB5 Programs	1,483.22	3.98
SECO Program	447.10	1.29
Wind-ERCOT Program	2,880.74	5.69

Crafting a Successful Solar Program

For any state seeking to justify an early financial commitment to solar energy, it is imperative to value the strengths of solar energy and to not overlook the weaknesses of conventional generating options. Components of the start-up plan to promote solar energy include:

Long-Term Perspective—Virtually any significant actions in the utility business portend multi-year time scales. In fact, the cumulative time for planning, construction and operation of utility power plants typically represents time scales on the order of half a century. Solar energy should also be judged over a similarly long time frame.

Evaluate Solar as an Overall Program — A solar *program* is far more than the initial projects installed during program start-up. Conventional power plants can take billions of dollars of investment and many years—in the case of nuclear technology, approximately 10 years—before they begin to produce any power. A solar program similar in scale to a major power plant (say 1,000 MW) and operating over a similar lifetime may be *more cost effective* than the comprehensive costs of a new conventional power plant, especially if solar is viewed as high value peaking energy and environmental and economic development benefits are internalized.

Partnership between Community and the Utility—Rooftop solar generation systems represent a significant opportunity for a utility and customer to jointly participate in development of onsite power production. By working together, utility solar funds are leveraged to maximize solar development per utility dollar invested. This is significant, in that historically, the utility made 100% of the capital investment needed for new power production facilities. Yet even during solar program start up, the utility will likely be able to reduce its capital contribution for new solar installations down into a range of 50% to 80% of installed costs. Throughout solar program start-up, the utility's share of capital costs will drop. This model is especially relevant to municipal utilities or statewide programs.

It should be noted that rebates for solar electric generation are fundamentally different from energy efficiency rebates, since the norm is for customers to own household appliances and utilities to own power plants. In an energy efficiency program, the utility gives money to the customer to influence the customer to install a better appliance. With a solar rebate program, the reverse is true. The customer in essence, contributes matching money to the utility to bring about the installation of a "better" power plant in the community, fueled by the sun and without need for additional transmission and distribution wires.

F.2. Recommended Incentives to Promote Onsite Renewable Energy in Texas

Specific Incentives to create Demand for Onsite Renewables:

1) Require specific levels of diversity in Texas' Renewable Portfolio Standard (RPS) by articulating specific goals by specific dates with penalties for non-compliance. Requiring 250 MW of onsite renewable capacity by 2015 will assure a foundation of activity for stimulating this market sector in Texas. (As has been observed for wind, once a market sector is "awakened", it may quickly exceed a modest RPS goal.)

2) Require a minimum level of renewable energy usage for new school buildings. Schools represent a unique opportunity as an educational platform and as an institutional customer with a long-term perspective on energy costs. The State Power Program could help facilitate deployment of onsite renewables, especially if school districts were encouraged to aggregate their loads to achieve more significant economy of scale for distributed renewable generation.

Specific Incentives to lower the cost of Supply of Onsite Renewables:

3) Expand onsite renewable usage through "buy-down" incentives funded through the System Benefits Charge. Expanding funding for the Goal for Energy Efficiency is a straightforward means of funding onsite renewable generation, since onsite renewables already qualify for energy efficiency standard offer incentives. For the purposes of this report, any specific funding intended to promote onsite renewable energy needs to be IN ADDITION TO the funding intended for energy efficiency and demand response initiatives, even if all are administered through a common program. Specific features of the onsite renewables "buy-down" include:

   - That it can be complementary to RPS requirements by reducing the cost of compliance of an onsite renewable set-aside (if RPS is not used to stimulate demand, relatively higher "buy downs" may be used to kick-start the market);

   - Allowing special incentives (higher than standard offer amounts) to provide sufficient initial stimulus for high value renewables (such as PV);

   - Allowing school districts and governmental jurisdictions to aggregate onsite loads;

   - encourage onsite distributed wind and biomass for large electric consumers (which may require higher project award caps for these technologies);

   - Ensuring utilities administering the programs are not financially penalized;

   - Providing total funding for onsite renewable energy programs that grow from $50 million per year to a maximum of $170 million per year (equivalent to

$0.44/MWh across all sales in Texas; or up to 75 cents/residential customer /month if spread equally across all load in Texas competitive market).

Enabling Policies: Address Market Structural Issues:

4) Strive for uniform interconnection standards statewide;

5) Allow net metering for small onsite renewables, through the use of a single meter that runs forward and backwards, and also encourage deployment of advanced electric meters (smart meters) capable of real-time pricing and communication with the utility;

6) Establish workforce training programs for installers, technicians, and inspectors;

7) Educate policy-makers, energy consumers and the general public on opportunities for onsite renewable generation;

8) Encourage optional offerings for renewable energy generation on new housing and other buildings.