Addressing Pollution from Legacy Coal Power Plants in Texas

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Executive Summary: Addressing Pollution from Legacy Coal Power Plants in Texas

As Energy Future Holdings faces an uncertain financial future, three of its legacy coal-fired power plants from the former TXU feature prominently in the energy and air quality challenges confronting Texas. These 1970's vintage facilities – Big Brown, Martin Lake, and Monticello – are among the leading emitters of air pollutants and greenhouse gases in Texas. Their emissions of nitrogen oxides (NO_x) – more than 30,200 tons in 2011 – have been shown to contribute to excess levels of ground-level ozone in the Dallas-Fort Worth and Tyler-Longview-Marshall regions. Substantial reductions in NO_x emissions will be needed in order for these regions to attain air quality standards for ozone, a pollutant that can cause respiratory illness and premature mortality. Their emissions of sulfur dioxide (SO_2) have been modeled to exceed SO_2 standards up to 10 miles downwind of each plant, and contribute to unhealthful particulate matter over far longer distances. Ozone and particulate matter increasingly have been linked to illness and mortality, prompting the Environmental Protection Agency to tighten air pollution standards for these pollutants. Meanwhile, these three power plants ranked nationally among the top five emitters of mercury, a potent neurotoxin linked to IQ impairment and other developmental problems in children.

Given the outsized contribution of these power plants to air pollutants and greenhouse gases relative to electricity output in Texas, substantial emission reductions could be achieved by installing retrofit pollution control devices or replacing the plants with natural gas or renewable electricity generation (Figure E1). Retrofit controls such as selective non-catalytic reduction or selective catalytic reduction, dry sorbents, and activated carbon injection could substantially reduce emissions of NO_x, SO_2, and mercury respectively. However, these controls would entail hundreds of millions of dollars of investments in aging facilities whose emission rates would continue to far exceed those of new power generators, at a time when low power prices have already severely impaired their financial viability.

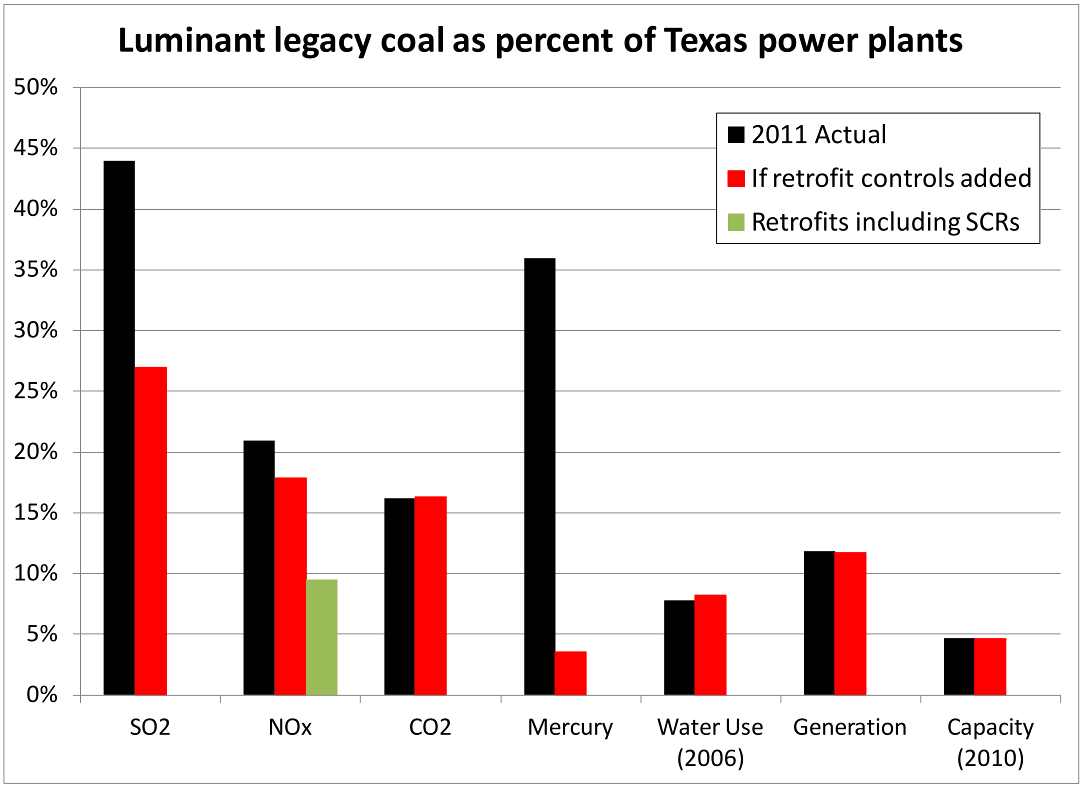


Figure E1. Emissions from Big Brown, Martin Lake, and Monticello as a percentage of Texas power plants in 2011, with and without hypothetical retrofit controls (see Figure 3.1 for references)

If the power plants are retired rather than retrofit, new electricity supply or reductions in demand will be needed to replace their 5,495 MW contribution to peak power capacity. The ERCOT electricity market which covers most of Texas already faces a tight balance between supply and demand on peak summer afternoons, which could be exacerbated as demand grows and old facilities are retired. A review of options for new power generation shows that natural gas, geothermal energy, coastal wind, and solar photovoltaics could all provide power at similar prices to Texas ratepayers after factoring in the influence of federal incentives, with far lower environmental impacts than the legacy coal generation. Natural gas generation provides readily dispatchable electricity and may achieve the lowest costs of new generation options under current conditions. However, the renewable power options would achieve lower environmental impacts and protect ratepayers from both uncertain future natural gas prices and potential regulation or taxation of greenhouse gas emissions (Table E1). Measures to promote energy efficiency and demand response would likely provide the most cost-effective replacement of power generation, and could complement the supply-side options.

Table E1. Costs and emissions per 1 MWh of electricity from retrofit and replacement options. (See Table 3.4 footnotes for references and explanations of assumptions)

	Cost	Cost with incentives	Cost with incentives + \$25/ton CO_2 [3]	SO_2 (lb)	NO_x (lb)	CO_2 (lb)	Hg[7] (10^{-5} lb)	Water use[8] (gal)
Legacy coal 2011	\$39.63	\$39.63	\$66.34	9.18	1.48	2,137	8.9	300
Coal with UBS retrofits	\$42.89	\$42.89	\$70.02	4.36	1.23	2,170	0.9	309
Coal with SCRs	\$45.29	\$45.29	\$72.42	4.36	0.59	2,170	0.9	309
Natural gas	\$65.90	\$65.90	\$79.51	0.01	0.36	1,089	0.0	270
Geothermal	\$76.10-\$88.20	\$65.10-\$77.20	\$65.65-\$77.75	0.17	0.00	44	0.0	5
Coastal wind	\$51.00-\$83.40	\$40.00-\$72.40	\$40.00-\$72.40	0.00	0.00	0	0.0	1
Solar	\$140.30	\$77.90-\$101.18	\$77.90-\$101.18	0.00	0.00	0	0.0	26
Energy efficiency	\$35.00	\$35.00	\$35.00	0.00	0.00	0	0.0	0

Given the inherent competitive advantages of legacy power providers and the obstacles to investment in new power generation and demand reduction, action may be needed to foster the most sensible outcomes. Specifically, the following policy options should be considered:

1. **Disincentivize high-emitting power options:** Legacy power plants enjoy enormous competitive advantages from having already paid their capital costs, and from being held to environmental regulations far more lax than would be required of any new generation. Those advantages often outweigh the greater efficiency and performance of new facilities, and have prompted many legacy facilities to operate far beyond their expected lifetime. Additional incentives or special treatment of high-emitting power plants are not warranted.
2. **Foster a viable market for low-emitting new power generation:** Potential new providers of renewable electricity have been hindered in obtaining financing due to volatile and uncertain prices for electricity. Some of the approaches being pursued to promote new generation, such as raising the caps on peak power prices, raise costs and risks for electricity retailers and consumers without enhancing the financing prospects for new generation. New power generation may be more effectively promoted by providing modest incentives for options such as solar, geothermal, and coastal wind, which can reduce overall system costs by alleviating price spikes at times of peak demand.

3. **Enhance the Texas Renewable Portfolio Standard:** The Texas Renewable Portfolio Standard (RPS), which sets a target for power generation from renewable sources, was crucial to catapulting the state to its lead role in wind power generation. However, with the initial targets already achieved, the state's RPS now lags behind the more ambitious targets set by many other states. Furthermore, the Public Utility Commission has yet to implement an RPS provision authorized by the Legislature to specifically promote non-wind renewable energy. These other renewable energy sources can typically be far more effective than inland wind at providing power during the peak summer afternoons when it is needed most. An enhanced RPS program could be designed to specifically target renewable power options based on their ability to provide peak power. The renewable energy credits that would accompany a non-wind RPS would provide valuable incentives to enable the construction of new solar or geothermal generation.
4. **Enhance the Texas Energy Efficiency Portfolio Standard:** Electricity providers have helped their customers achieve substantial reductions in power demand through the existing Texas Energy Efficiency Portfolio Standard. Research by the American Council for an Energy-Efficient Economy indicates that substantial further improvements in energy efficiency and demand response could be achieved in Texas at far lower costs than new generation options. Demand response measures can be implemented far more rapidly than construction of large generating facilities, and may provide the most immediate and cost-effective relief for tight power markets in Texas.

Together, these options could foster the ability of electricity providers to offset any loss of generating capacity from the legacy coal-fired power plants, while enhancing air quality and minimizing costs to ratepayers.

Chapter 1

Air Quality Challenges in Texas

Air quality in Texas is impaired by several key pollutants. This chapter will review four of the challenges confronting the Texas environment: ozone, particulate matter, SO_2, mercury, and climate change. It will also provide context for considering the role of power plant emissions in these challenges.

1.1 Ozone

Though the protective ozone layer in the stratosphere occurs naturally, ozone near the ground is an air pollutant that forms from complex mixtures of emissions. The warm and sunny conditions of Texas summers foster the formation of ground-level ozone, especially on days with wind flow patterns that allow pollution to accumulate. Exposure to high levels of ozone has been linked to a variety of health problems, including increased rates of respiratory ailments and hospitalizations. Epidemiological research has also found that daily mortality rates are correlated with high levels of ozone pollution [1, 2]. For example, Bell et al. (2004) found that a 10-ppb increase in the previous week's ozone was associated with a 0.52% increase in daily overall mortality and a 0.64% increase in daily cardiovascular and respiratory mortality. Over the long-term, exposure to ozone may increase rates of mortality from respiratory disease [3]. Exposure to ozone very early in life during respiratory tract development may have profound effects on airway functioning, and therefore young children may be especially susceptible to adverse effects of ozone [4]. The results of an 18-year study in California indicated that the current ozone levels contribute to an increased risk of hospitalization for children with respiratory problems [5]. Most recently, Rice University statisticians have reported a link between ozone concentrations and cardiac arrest in Houston [6].

Beyond its harmful effects on human health, the oxidizing effects of ozone also damage plants, impairing their growth rates, reproduction and overall health [7-9]. Ozone reduces yields for timber and many economically important crops such as soybeans, wheat, and cotton. Plants respond to ozone by closing their stomata, impairing the ability of trees to sequester carbon dioxide from the atmosphere and thus contributing to global warming [10]. Ground-level ozone also directly contributes to global warming by acting as a powerful greenhouse gas. Global concentrations of ozone have risen by around 30% since the pre-industrial era, making ozone the third most important contributor to climate change after CO_2 and methane [11].

Texas has struggled for three decades to attain federal standards for ground-level ozone air pollution, despite substantial progress in curtailing the emissions that form ozone. Since ozone is not emitted directly, reductions in ozone must be achieved by controlling one or both of its precursor gases: nitrogen oxides (NO_x) and volatile organic compounds (VOCs). Most studies show that ozone in most of Texas, including the Dallas-Fort Worth region and urban and rural regions of central and eastern Texas, is controlled most effectively by reducing emissions of NO_x [12]; both NO_x and VOC controls may be important to reducing ozone in the Houston region [13, 14]. Technologies such as catalytic converters, oxygen sensors, and ultra-low sulfur fuels have enabled vehicles to emit far less of the nitrogen oxides (NO_x) and volatile organic compounds (VOCs) that form ozone. The Texas Emission Reduction Plan, along with the state's inspection and maintenance program, has also contributed to reductions in mobile source emissions. Meanwhile, tighter regulations and installation of control devices at a broad array of industrial facilities has sharply curtailed their NO_x and VOC emissions.

Power plants are major emitters of NO_x but not VOCs. As their NO_x-rich plumes interact with VOCs emitted from vegetation or urban sources of pollution, ozone can form rapidly. Aircraft transects performed during the Texas Air Quality Studies in 2000 and 2006 allowed scientists to rigorously study the formation of ozone, particulate matter, and acidic gases in Texas power plant plumes [15-17]. Analysis and modeling of these observations by Zhou et al. (2012) found that more than 7 ozone molecules formed for every 1 emitted NO_x molecule in the Martin Lake plume, and more than 10 in the Monticello and Welsh plumes in 2006.

Power plants contributed 9.5% of Texas anthropogenic NO_x emissions in the most recent National Emissions Inventory (2008; Figure 1.1), down from 14.1% in 2002 due to the installation of control technologies. The most effective such technology is selective catalytic reduction (SCR) [18], whose installation at the W.A. Parish power plant near Sugarland was an important component of ozone attainment plans for Houston. SCR can reduce NO_x emissions by up to 90% to a floor of 0.06 lb/mmBtu, compared to 35% control achieved by SNCR [19]. However, SCR has been retrofit onto only one of the other pre-1993 coal facilities in Texas (Sandow), with the others relying on less effective selective non-catalytic reduction, low NO_x burner, and/or overfire air technologies. This includes Big Brown, Limestone, Martin Lake, Monticello, Pirkey, and Welsh, each of which has been shown to contribute 0.4 – 1.8 ppb of ozone to the Dallas-Fort Worth region on some days [20]. Some of these facilities also contribute to ozone formation in the Waco and Tyler-Longview-Marshall regions [21].

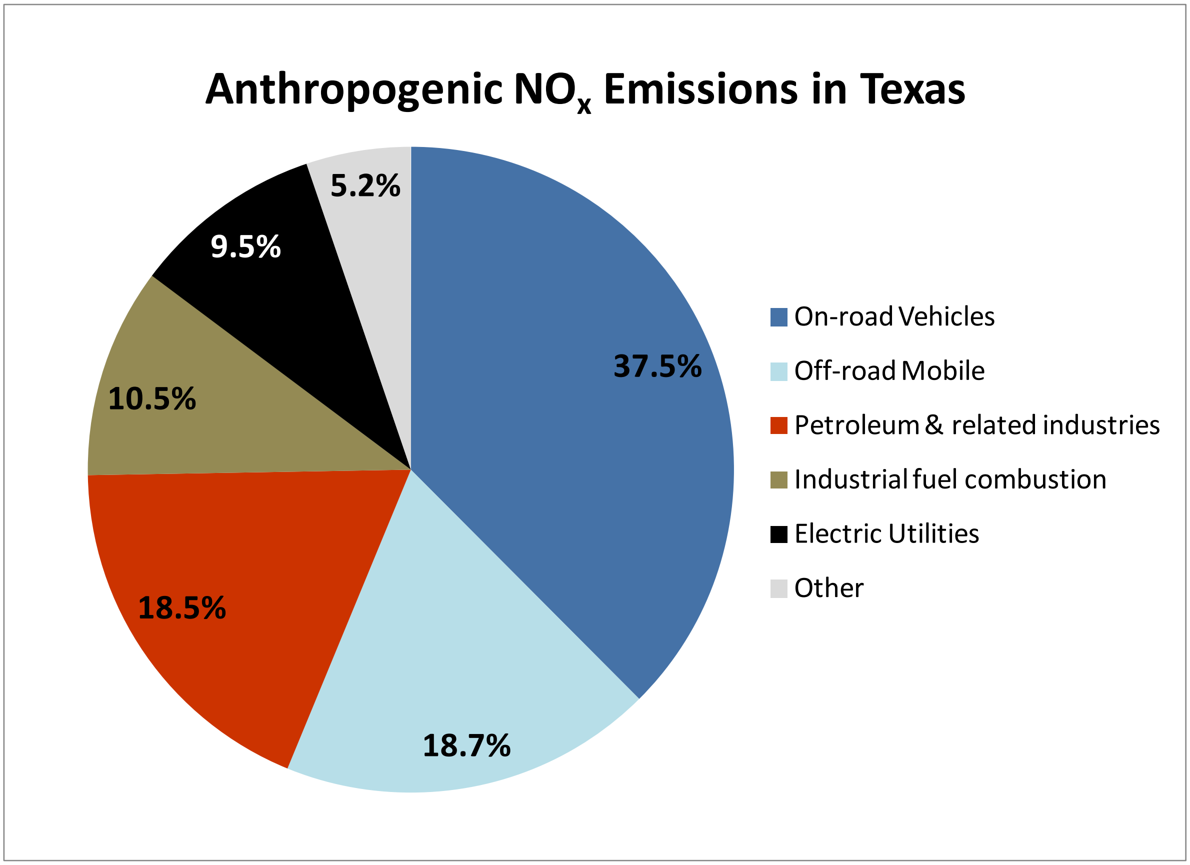


Figure 1.1. Sources of NO_x emissions in Texas in 2008 (US EPA, National Emissions Inventory)

Despite improvements from its very high levels at the turn of the century, ozone in most of Texas' largest cities remains far above the levels that are now considered protective of public health. Along with the Houston-Galveston-Brazoria and Dallas-Fort Worth regions which have long violated earlier ozone standards, Beaumont-Port Arthur, San Antonio, Tyler-Longview-Marshall, and Waco all reported ozone levels for 2010-2012 that exceed the current 75 parts per billion (ppb) standard (Figure 1.2). This standard was set in 2008 despite recommendations from US EPA's Science Advisory

Committee that even more stringent limits of 60-70 ppb were necessary to protect public health. US EPA is now reconsidering whether to tighten the ozone standard to a level in this range.

Whether or not the ozone standards are further tightened, it is clear that substantial additional emission reductions will be needed in order to achieve compliance throughout Texas. Since peak afternoon ozone concentrations in most of Texas are primarily responsive to NO_x controls [12, 14], reductions of NO_x emissions from all major sources, including power plants, will be crucial to attaining the standards and protecting public health.

If insufficient progress is made, continued non-attainment of federal ozone standards would have important consequences for Texas. Non-attainment regions are subject to transportation conformity, which hinders their ability to obtain federal funds for transportation projects. EPA imposes stringent and sometimes costly new source review requirements on facilities operating in non-attainment areas, which can discourage businesses from expanding in or relocating to these regions. In terms of human health, non-attainment signifies that millions of Texans continue to be exposed to excessive levels of a pollutant associated with respiratory illness, asthma attacks, and premature mortality. These health impacts impose an economic cost through increased medical bills and missed work days. Non-attainment poses other economic costs on Texans as well. In addition, non-attainment impairs perceptions of the quality of life and environmental health of a region, making it more difficult to attract new businesses and highly-skilled professionals.

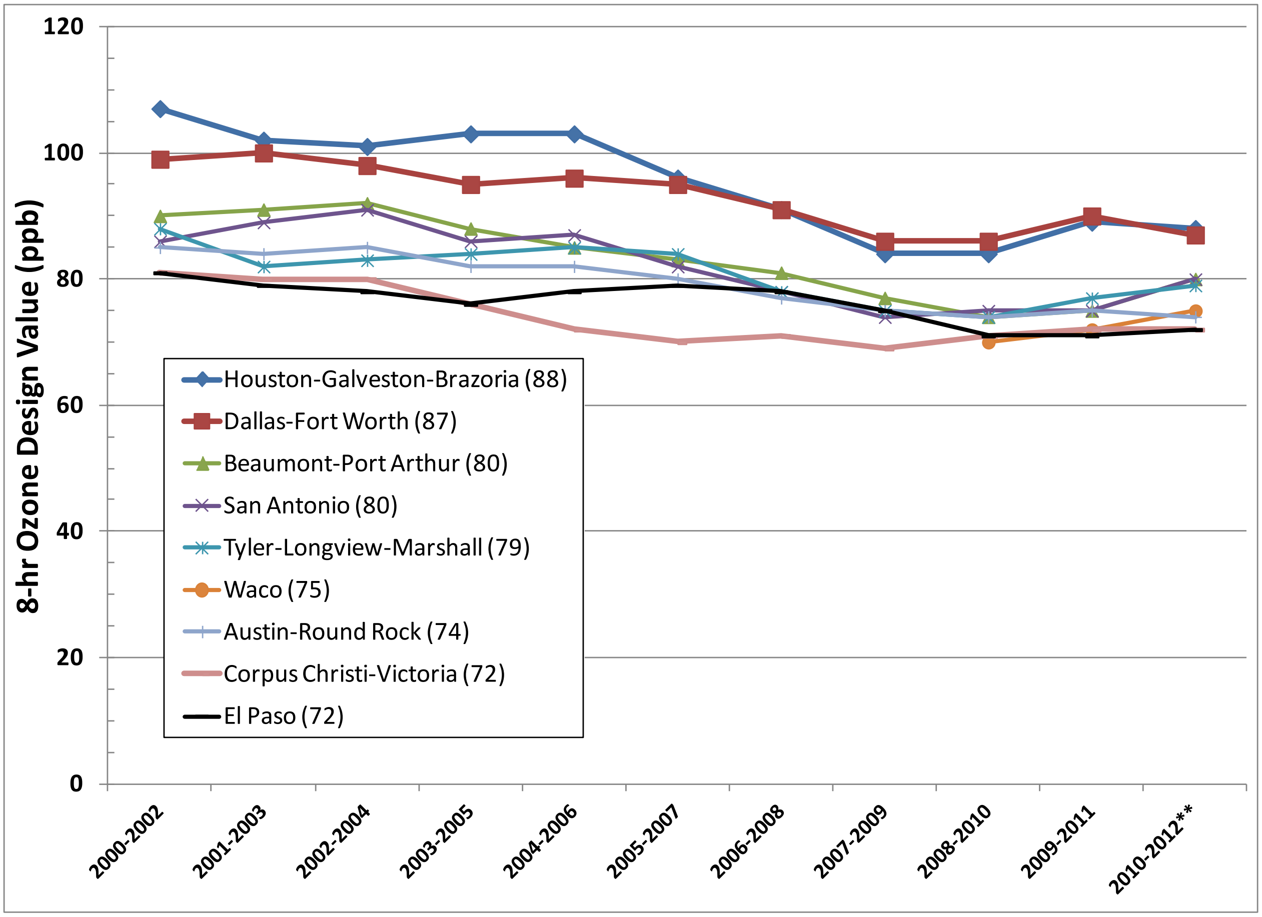


Figure 1.2. Ozone levels in Texas metropolitan regions. The most recent design values are shown in parentheses for comparison to the 75 ppb ozone standard. (Data from US EPA and TCEQ)

1.2 Particulate Matter

Particulate matter (PM) originates both from direct emissions of particles ("primary") and from "secondary" formation in the atmosphere from SO_2, NO_x, ammonia, and hydrocarbon gases. Particles smaller than 2.5 micrometers in diameter, are known as $PM_{2.5}$ or "fine particles," and are thought to be especially harmful to human health because they can penetrate deeply into the lungs [22]. Population-based studies in hundreds of cities around the world have demonstrated a strong link between PM and premature deaths, respiratory and cardiovascular diseases, and hospital admissions [23-26]. Long-term studies of children's health have demonstrated that particle pollution may significantly impair lung function and growth in children [27, 28].

Fine particles also form a haze that impairs visibility. In many parts of the country, especially in the national parks, the visibility has been reduced by 70% from natural conditions [29]. Fine particles can remain suspended in the air and travel long distances, impairing visibility even in areas far from major emission sources. For example, under some meteorological conditions, power plant and urban emissions from eastern Texas can be major contributors to visible haze in Big Bend National Park [30]. Under the Regional Haze Rule, state and federal agencies are working to control haze levels in pristine wilderness and national park areas. Those efforts will require substantial reductions in $PM_{2.5}$ levels.

Responding to epidemiological evidence pointing to substantial health impacts of $PM_{2.5}$ even at levels once considered safe, U.S. EPA in December 2012 tightened the annual $PM_{2.5}$ standard from 15 $\mu g/m^3$ to 12 $\mu g/m^3$. The standard is evaluated based on three year averages known as "design values." All Texas monitors met the previous annual $PM_{2.5}$ standard, and particulate levels have generally been declining in Texas for the past decade (Figure 1.3) as vehicle and industrial emissions have declined. However, the Clinton Drive monitor in Houston exceeds the new 12 $\mu g/m^3$ standard, which could lead US EPA to designate the region as non-attainment if this persists after 2012 data is finalized. A few other monitors in Houston, Texarkana, and Dallas meet the standard by only a narrow margin. Attainment is determined based on the highest reported design value, so even a single monitor can bring an entire region into non-attainment status along with all of the regulatory and economic burdens that this entails.

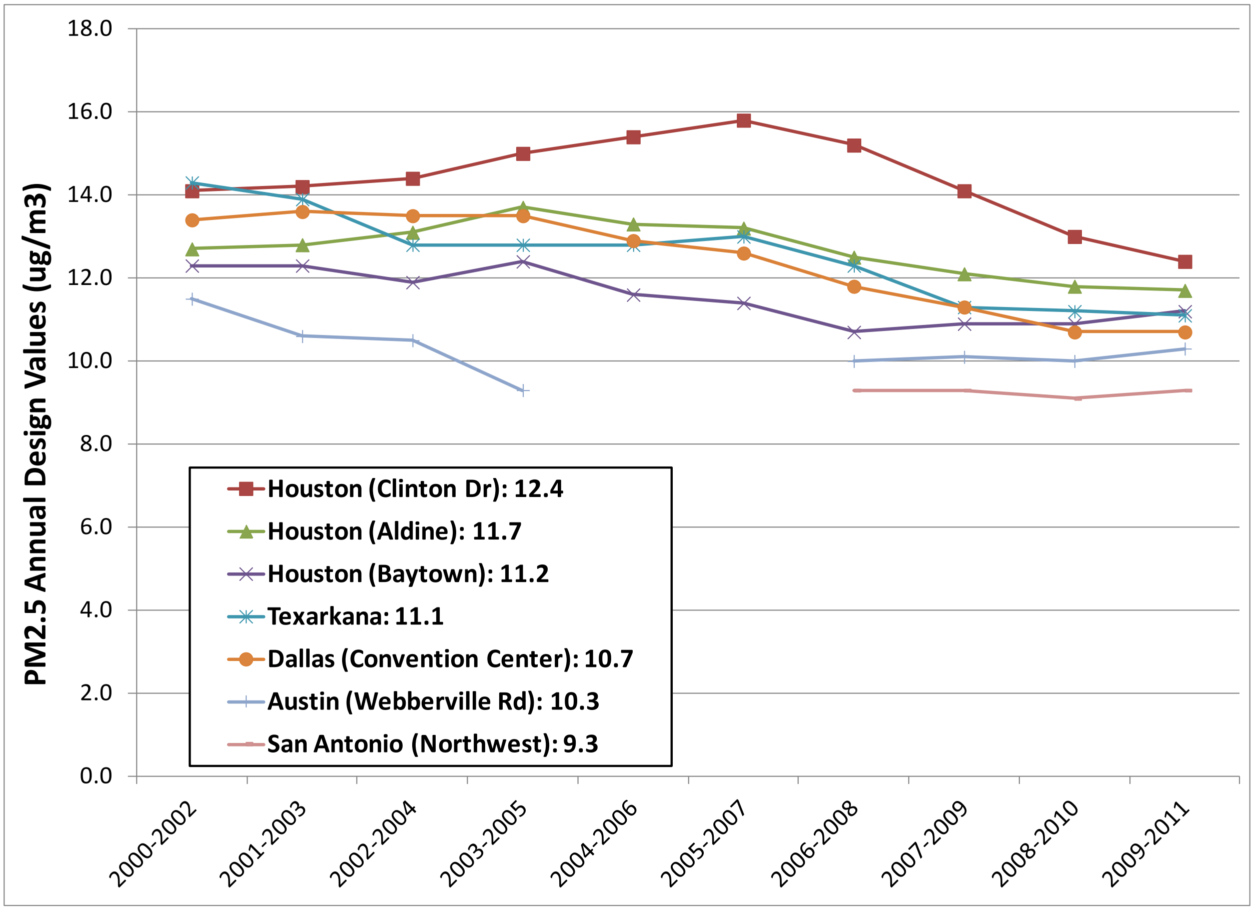


Figure 1.3. $PM_{2.5}$ design values at monitors with the highest concentrations in Texas cities. Legend shows the 2009-2011 design value in μg/m³. (U.S. EPA, from TCEQ data)

While $PM_{2.5}$ has traditionally received far less attention in Texas than the persistent ozone non-attainment challenge, the narrow margins between measured values and the new standard and the growing scientific understanding of $PM_{2.5}$ health effects are likely to create new impetus for controlling $PM_{2.5}$ to attain or maintain compliance. Houston's Clinton Drive monitor in the Houston Ship Channel has received special attention, since its $PM_{2.5}$ levels have long exceeded 12 μg/m³, and briefly exceeded the old 15 μg/m³ standard. Controls of localized sources such as a nearby unpaved lot trafficked by heavy machinery have yielded substantial benefits, as concentrations of soil and dust particles have fallen by two thirds in just five years, according to TCEQ analysis of Clinton Drive PM observations (Figure 1.4). This leaves ammonium sulfates and organic carbon as the dominant contributors to $PM_{2.5}$ at Clinton Drive, each responsible for about 4 μg/m³ (Figure 1.4). These components of PM can be reduced by controlling any or all of three sources: the SO_2 emissions that oxidizes in the atmosphere to form ammonium sulfates; directly emitted organic carbon particles; or VOC gases that oxidize in the atmosphere to form secondary organic carbon particles. Given the narrow margins, even a small fractional reduction in any of these components could make a significant difference in whether Clinton Drive, and thus the Houston region, achieve attainment of the new standard.

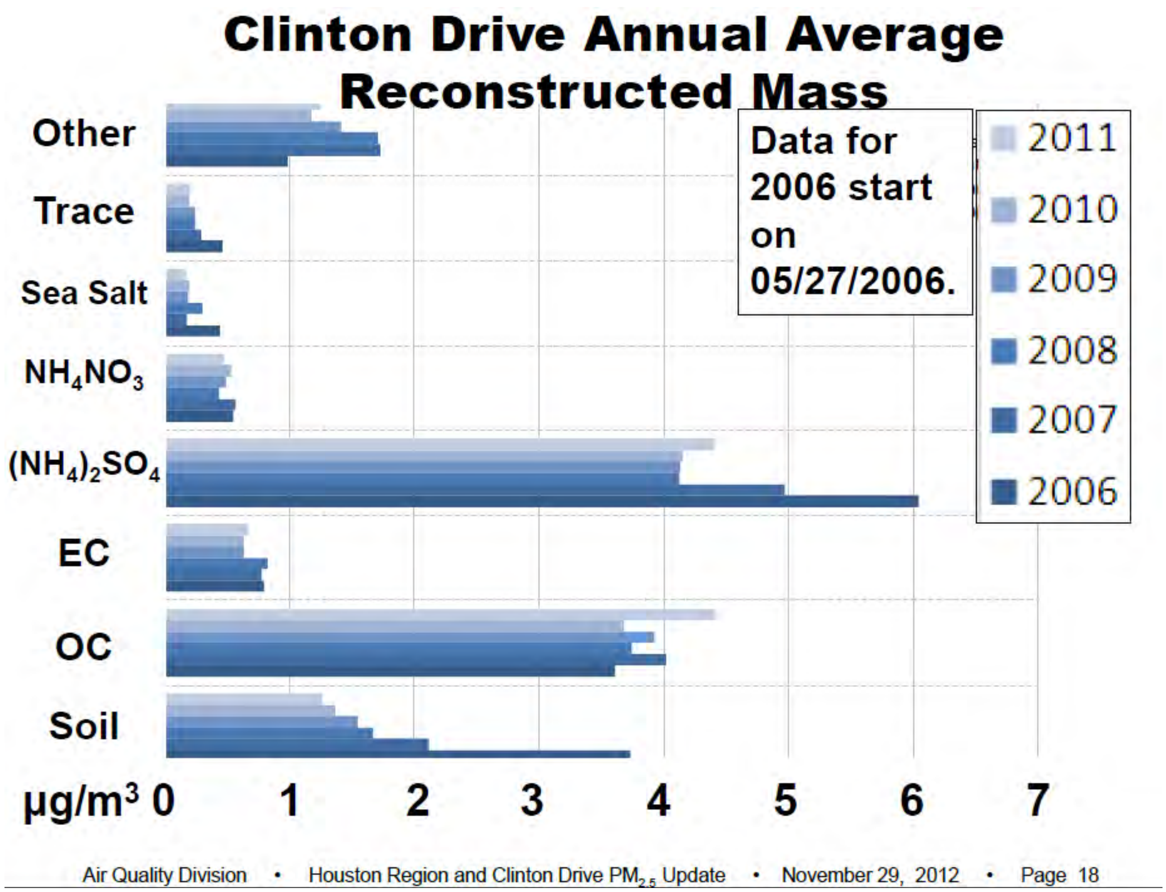


Figure 1.4. Composition of particulate matter at the Clinton Drive Monitor in the Houston Ship Channel. [31]

1.3 Sulfur dioxide (SO_2)

Apart from its contribution to fine particulate matter, SO_2 is also drawing increased attention in its own right. Short term exposure to high levels of SO_2 can cause an array of respiratory health problems including increased asthma attacks. Although most regions easily attained previous ambient standards for SO_2, standards issued by US EPA in 2010 are far more stringent, setting a 1-hour limit of 75 ppb (196 µg/m^3). The new standard has prompted extensive new dispersion modeling of SO_2 plumes from major sources to gauge their impact on attainment.

A series of studies prepared by AMI Environmental for the Sierra Club in 2011 applied AERMOD to model the SO_2 impacts of three major coal-fired power plants owned by Luminant: Big Brown, Martin Lake, and Monticello. The studies concluded that all three power plants, together with low levels of background SO_2, would lead to concentrations far exceeding the new ambient standards. The spatial scale of exceedances would span a radius of 6-10 miles in each case.

Table 1.1. AERMOD modeled SO_2 downwind of coal power plants (AMI Environmental, 2011)

Power Plant	1-hour SO_2 (4th highest) ($\mu g/m^3$)	Radius exceeding standard (miles)
Big Brown	517	6
Martin Lake	463	10
Monticello	357	6

1.4 Mercury

Mercury (Hg) is a neurotoxin that can significantly impact human health and child and fetal development even at very low levels. Emissions to the atmosphere followed by rainfall or dry deposition is the leading source of mercury to aquatic ecosystems [32]. In water bodies, mercury can be converted to the organic form, methylmercury, and then bioaccumulate in organisms within the food chain. Predatory fish at the top of the food chain accumulate the highest levels of mercury, posing a consumption risk to wildlife and humans eating those fish. Fish consumption is the primary source of methylmercury exposure in humans.

The most widely documented impact of mercury is the damage to neurological development in children exposed to mercury in utero or in infancy, resulting in impairment of IQ, attention and motor skills [33]. Trasande et al. (2005) found that 315,000-635,000 children are born each year in the U.S. with cord blood mercury levels associated with loss of IQ [34]. They estimated that this results in lost productivity of $8.7 billion per year, $1.3 billion of which they attributed to mercury emissions from U.S. coal power plants. EPA attributed lower monetized impacts to IQ impairment from mercury [35].

Other health effects of mercury may be important as well, though the impacts are less fully documented than childhood IQ and skills impairment. For example, some studies have linked blood mercury levels to cardiovascular disease in adults [36, 37]. There also numerous studies that have linked the environmental exposure to mercury to increased autism rates, with the autism risk increasing with proximity to the mercury pollution source [38-46]. Two of those studies originated in Texas: a University of Texas Southwestern study reported hair concentrations of mercury to be correlated with autism spectrum disorder severity [44], and a University of Texas Health Science Center at San Antonio study found a correlation between autism rates among Texas schoolchildren and power plant mercury emissions, with risks increasing with proximity to the plants [46]. However, some other studies have found no linkage between autism and mercury [47, 48].

The Texas Department of State Health Services issues mercury advisories if a mercury concentration in a water body is 0.7 mg/kg or greater. Water bodies with fish consumption advisories due to high mercury levels are shown in Figure 1.5. Most of the advisories are issued for lakes and reservoirs in eastern Texas, within the vicinity of the largest coal-fired power plants in the state. However, linking fish mercury levels to particular emission sources is complicated by the fact that mercury originates from both local and global sources.

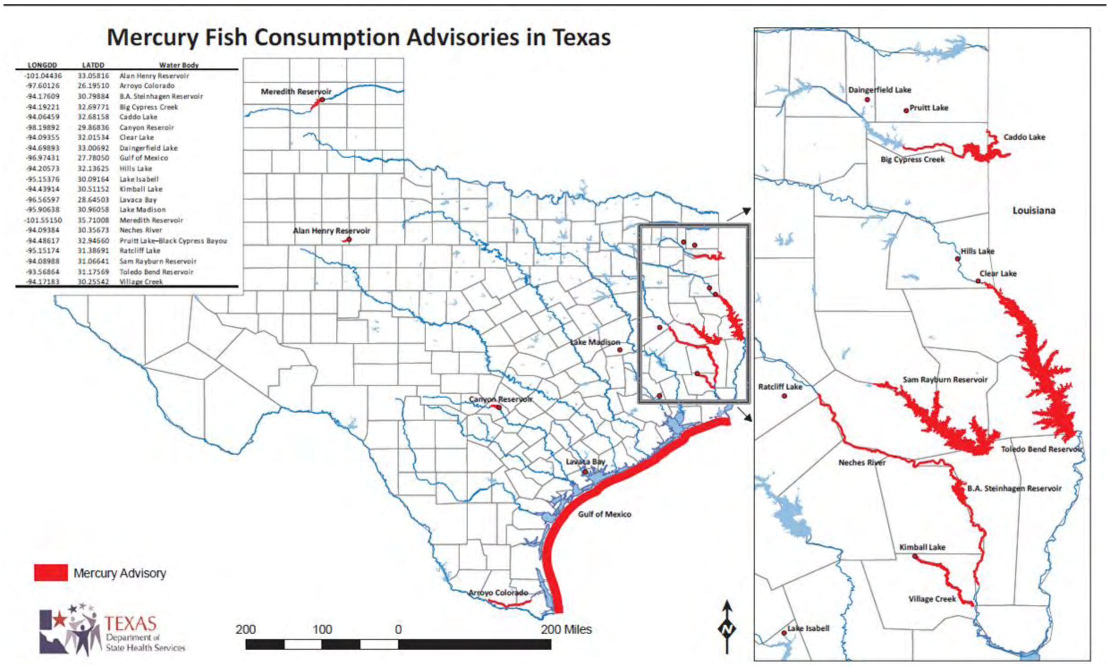


Figure 1.5. Mercury fish consumption advisories in Texas. (Texas Department of State Health Services)

1.5 Climate Change

Global climate models (GCM) available from the Intergovernmental Panel on Climate Change project that temperatures in the US could rise by 3.2°F to 7.2°F this century depending on different emission scenarios [11]. The GCM results also suggest a warmer Gulf Coast region by 2050, with the greatest increase in temperature occurring in summer and lowest increases in winter. The average temperature could increase by at least 2.7°F ± 1.8°F in the Gulf Coast region [49]. Along with the average temperatures, the frequency of extreme high temperature days will also increase. Global climate models differ on the impacts of climate change on precipitation amount, some predicting declines and others, increases for the Gulf Coast region [49].

Climate change may also have an effect on the outdoor air pollutant concentrations, especially ozone [50]. Ozone formation in the atmosphere is highly dependent on temperature. Ozone concentrations in the atmosphere show an increase in warm summer months, especially in the afternoons, when the temperatures are the highest [51]. At cooler temperatures, ozone precursors, NOx, react to form peroxyacetyl nitrates (PANs) instead of catalyzing ozone formation. Moreover, biogenic emissions of volatile organic compounds, which are also precursors to ozone, increase with the temperature [52]. Therefore, control of ozone formation becomes more challenging. Bell et al (2007) showed that the largest increases in ozone levels are predicted to occur in cities that already have high pollution levels, such as Houston [53].

Other potential impacts of climate change in Texas include the sea level rise, loss of coastal wetlands, erosion of beaches, saltwater contamination of drinking water, and decreased longevity of low-lying roads, causeways, and bridges. Relative sea level in the Gulf Coast is likely to rise at least 0.3 meter (1 foot) across the region and possibly as much as 1.6 meters (5.5 feet) in some parts of the region (in Galveston 0.7 -1.3 meter increase is projected). Relative sea level rise takes into account the combined effect of the sea level rise due to increases in temperature and melting of ice, and the changes in land surface elevation due to subsidence [49]. Sea level rise could increase the vulnerability of coastal areas to storms and associated flooding. Climate change is also related to certain illness outcomes associated with heat, air pollution, water contamination, and diseases carried by insects such as malaria, dengue fever, and Lyme disease [54].

Water resources are affected by changes in precipitation as well as by temperature, humidity, wind, and sunshine. Changes in stream flow tend to magnify changes in precipitation. Water resources in drier climates tend to be more sensitive to climate changes. Because evaporation is likely to increase with warmer climate, it could result in lower river flow and lower lake levels, particularly in the summer. For example, stream flow in the Colorado River is projected to drop 17-38 percent by 2050 due to climate change [55]. If stream flow and lake levels drop, groundwater levels could also be reduced. Global climate models project moderate to extreme drought conditions throughout Texas by the end of the 21st century. On the other hand, high-intensity rain events are expected to comprise a greater proportion of overall precipitation under climate change, which could increase the risk of flooding [56].

Carbon dioxide is the leading anthropogenic contributor to global warming [11]. It is also a difficult gas to control because it is ubiquitously emitted proportional to the amount of fossil fuel and biomass combusted and is not captured by traditional control technologies. Thus, control of CO_2 requires reducing the amount of fuel used (i.e., efficiency and conservation) or capture and storage of the CO_2, which is not yet in widespread commercial use. Carbon dioxide lasts for years in the atmosphere, so CO_2 emitted in one location can contribute to climate change worldwide.

Texas emits more CO_2 from fossil fuel combustion than any other state: 653 million metric tons in 2010, or 12% of the US total (Figure 1.6). Electric power generation is the largest source of CO_2 emissions in Texas, representing 34% of the total in 2010 (Figure 1.6). Much of this comes from coal-fired generation, which consumed 110 million short tons of coal in 2011, more than any other state.

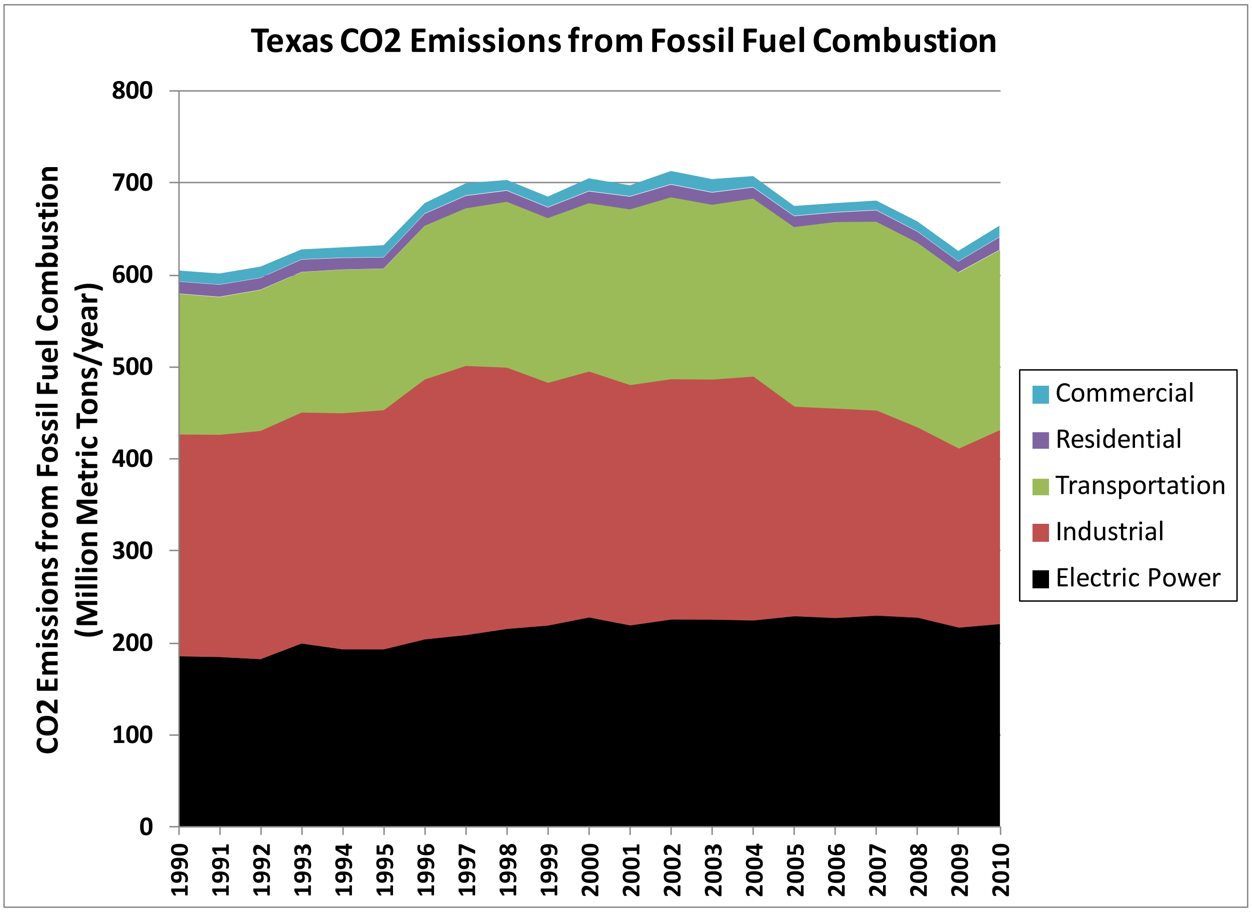


Figure 1.6. Texas CO_2 emissions from fossil fuel consumption by sector (1990-2010). (Data from US EPA at http://epa.gov/statelocalclimate/resources/state_energyco2inv.html)

Chapter 2

Texas Electricity: Supply, Demand, and Impacts on Air Quality

2.1 Electricity Supply and Demand in Texas

Texas leads the nation in total electricity consumption and production (US EIA). Per-capita electricity consumption by Texans is 17% higher than the national average and more than twice that of Californians (California Energy Commission, Energy Almanac). The high per capita consumption rates indicate substantial opportunity to reduce consumption through efficiency and conservation measures. While some of the high consumption rate reflects large energy-intensive industries in Texas such as petroleum refining and petrochemical production, the largest sectors of electricity consumption are residential and commercial, together representing almost three quarters of electricity use (Figure 2.1). The residential and commercial sectors are especially important to the challenge of peak electricity demand, since the air conditioning of homes and businesses drives demand on hot summer afternoons. These sectors have also been the fastest growing, with growth of 76% and 106%, respectively, since 1990, compared to only 21% growth in industrial power consumption.

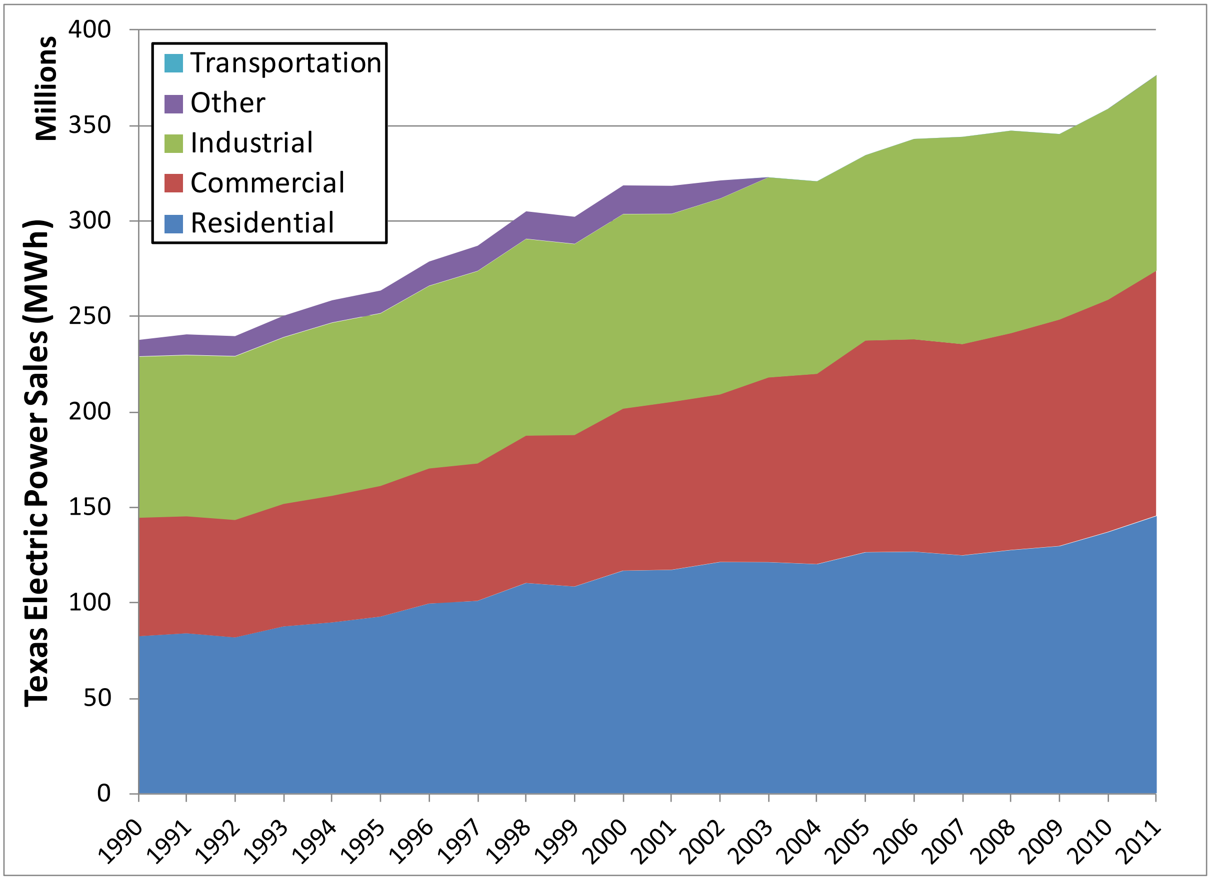


Figure 2.1. Sales by the Texas electric industry. The "other" category was absorbed into the remaining categories in 2003. (US EIA data from http://www.eia.gov/electricity/data/state/)

Natural gas and coal are the dominant sources of electricity in Texas, with the balance provided by nuclear and a growing amount of wind farms (Figure 2.2). The coal power plants typically provide baseload power, whereas natural gas is used for both baseload power (often from efficient combined cycle facilities) and peaking power (typically simple cycle combustion turbines). The state's coal power plants are concentrated in the eastern part of the state, while most wind generation occurs in the Panhandle and western part of the state (Figures 2.3 and 2.4).

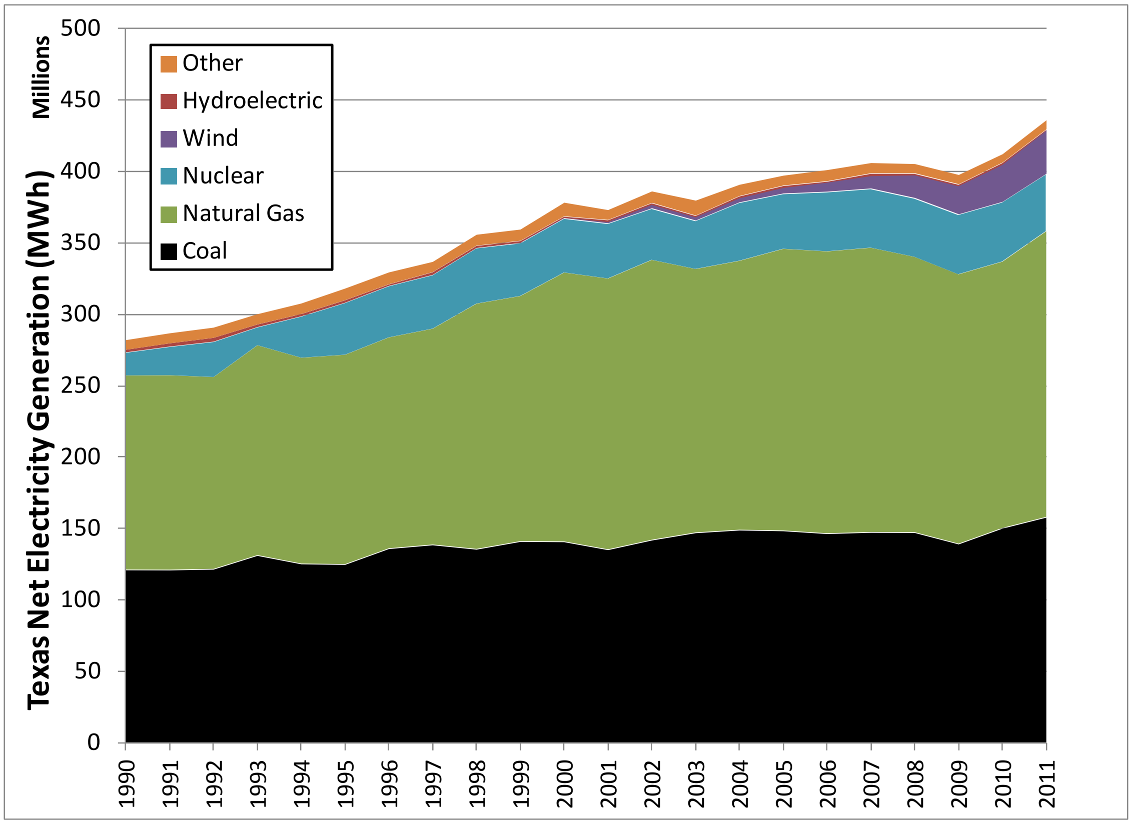


Figure 2.2. Net generation from the electric power industry in Texas. (US Energy Information Administration)

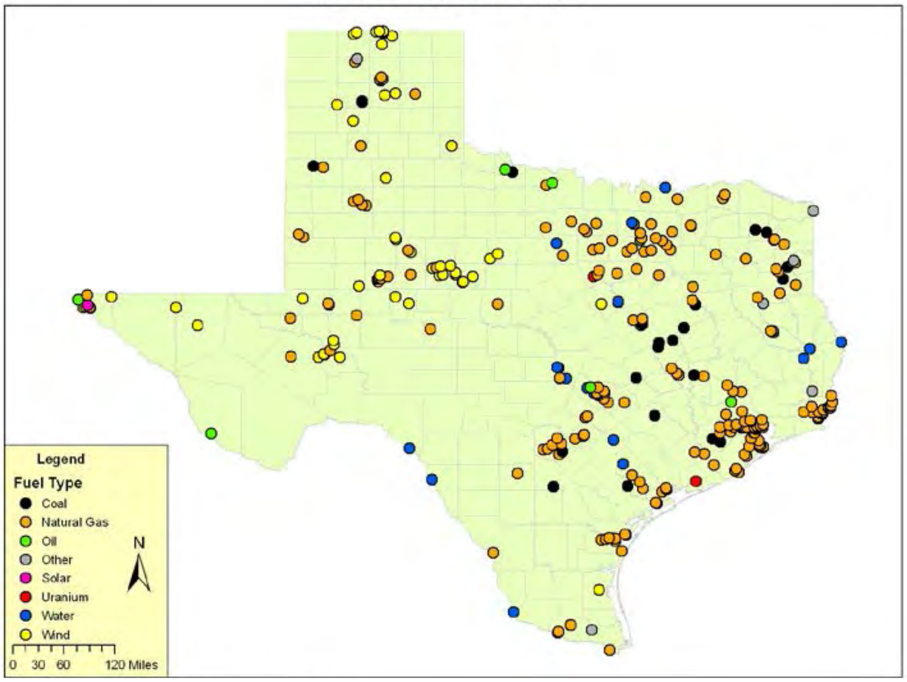


Figure 2.3. Texas power plants by fuel type. (Platts GIS Geospatial Mapping Data, 2006)

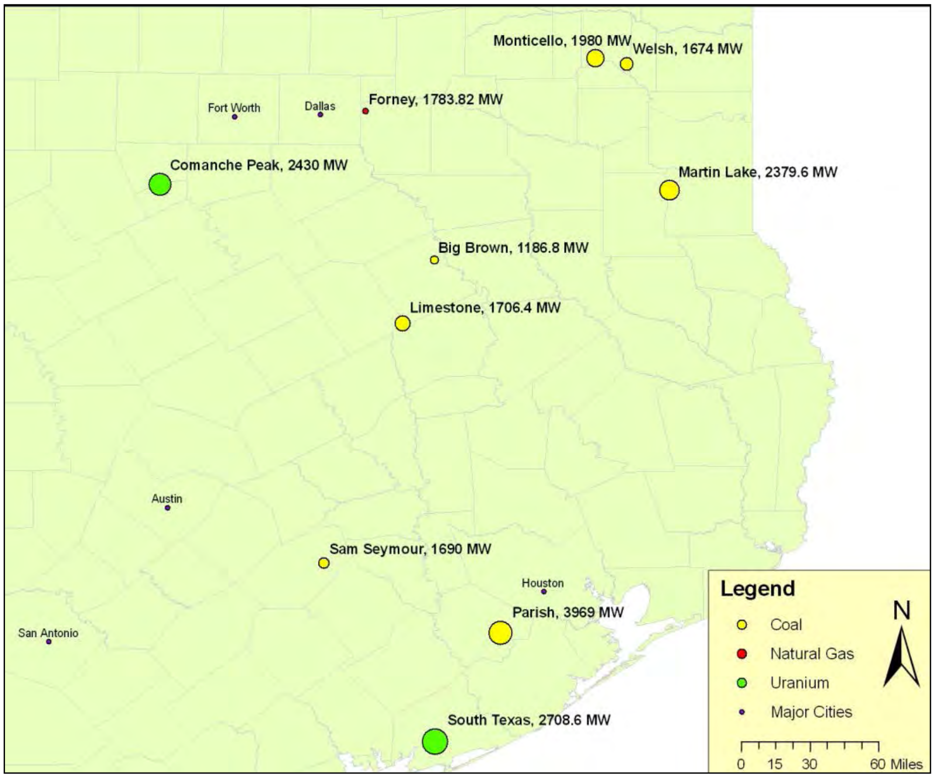


Figure 2.4. Largest generating plants in Texas in 2006 by capacity. (Platts GIS Geospatial Mapping Data, 2006)

2.2 The ERCOT system

Eighty-five percent of the Texas electricity load occurs within the Electric Reliability Council of Texas (ERCOT) system (Figure 2.5), the only entirely intrastate grid in the continental U.S. By contrast, other parts of the U.S. are served by regions connected through the Western Interconnect and Eastern Interconnect power grids. Due to the relatively isolated nature of the ERCOT grid, electricity demand in Texas must primarily be satisfied by electricity generated within the state.

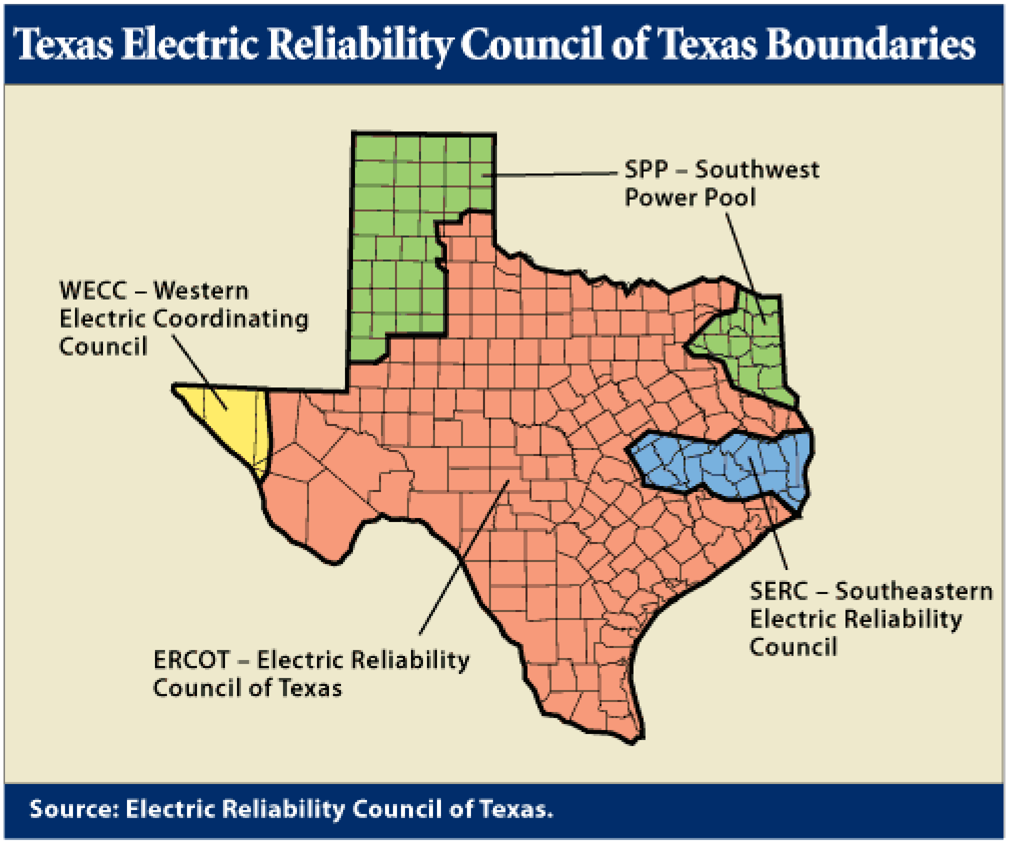
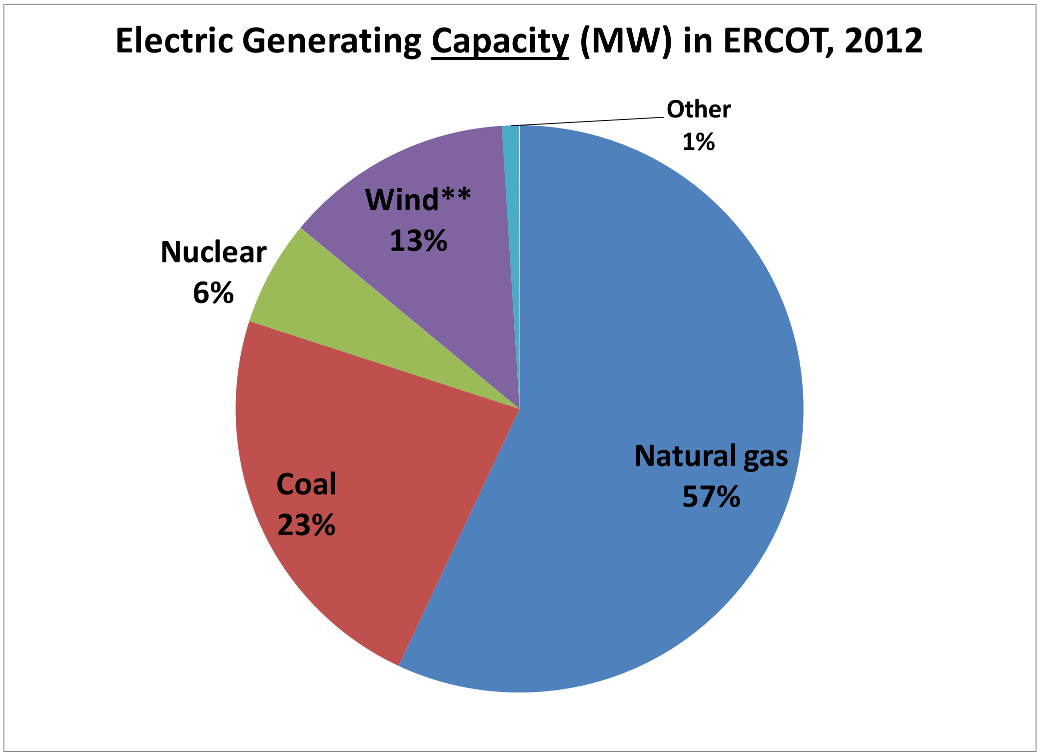


Figure 2.5. Management of electricity grids in Texas. (Texas Comptroller of Public Accounts, The Energy Report 2008)

Within ERCOT, natural gas is the leading source for electricity generation (45%), followed by coal (34%), nuclear (12%) and wind (9%) (Figure 2.6). It is important to distinguish between capacity, which is the amount of power that each source can provide, and the actual amount of electricity generated by each source. Most coal and nuclear power plants are operated year-round for baseload generation, shutting down only for maintenance or malfunctions, and thus represent a larger share of overall generation than capacity (Figure 2.6). Natural gas is used in both baseload and peaking plants, and wind power varies with meteorological conditions, so they supply smaller shares of generation than their capacity. Because winds are often weak during summer afternoons when electricity demand is highest, ERCOT multiplies wind capacity by an availability factor of just 8.7% in its summer peak reliability assessments. This is toward the low end of the 8.0-18.5% range that other electric reliability regions apply to wind.



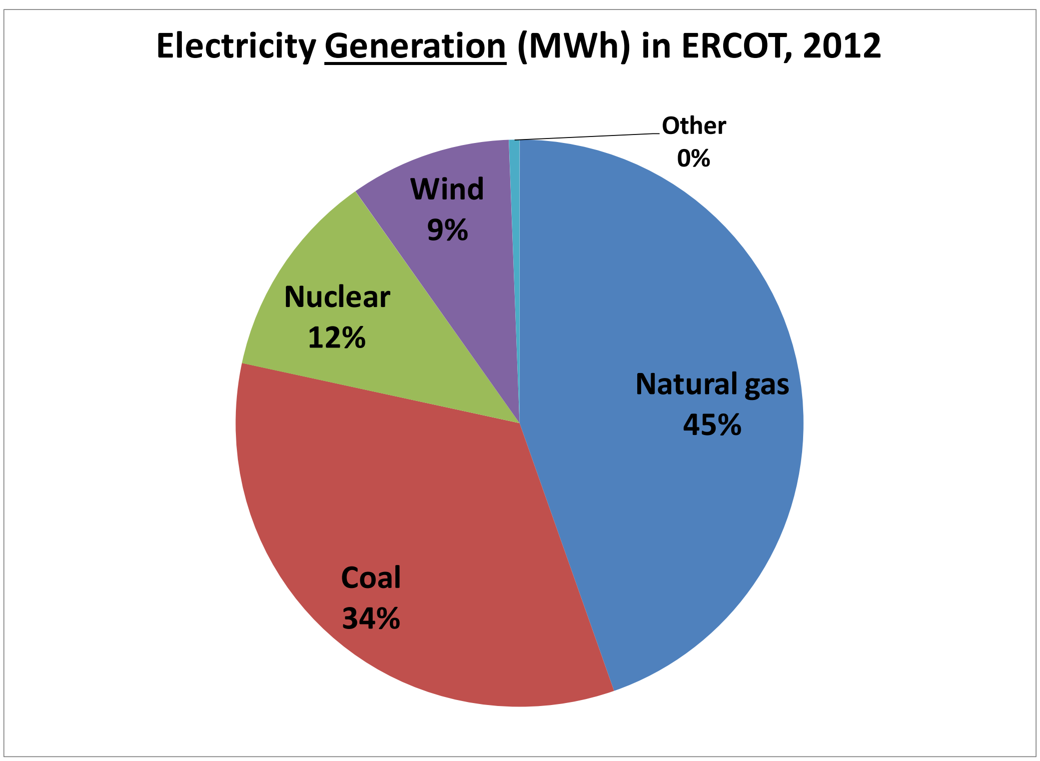


Figure 2.6. Electric generating capacity (top) and electricity generation (bottom) by fuel in ERCOT in 2012. **The capacity graph does not include the 8.7% availability factor that ERCOT applies to wind for summer peak capacity. (ERCOT Quick Facts, January 2013)

2.3 TXU Legacy Power Plants: Big Brown, Martin Lake, and Monticello

Three of the state's coal-fired power plants have attracted special attention due to their high rates of emissions and their ownership by Luminant, a wholesaler power producer formed during the private equity buyout of TXU in 2007. Some analysts have speculated that Energy Future Holdings (EFH) and its Texas Competitive Electric Holdings unit, which includes Luminant wholesale and TXU retail, face precarious financial circumstances due to $37 billion in debt and low power prices. Most of the debt was incurred when the company formed through the buyout of TXU, with expectations of higher power prices before the booming gas availability led natural gas and electricity prices to sink. The impact of EFH's evolving financial situation on the fate of these 1970's vintage power plants remains unclear.

Table 2.1 summarizes some of the key features of these power plants. The power plants together provide 5,495 MW of peak capacity [57]. For context, ERCOT's overall 2013 summer resources are 74,950 MW [57], and electric generating capacity in Texas statewide is 117,734 MW (US EIA data for 2010). The power plants achieve efficiencies of 32-33%, which is in line with other power plants of their 1970's vintage. However, it is far less efficient than the greater than 39% that US DOE considers readily achievable at new supercritical pulverized coal power plants before CO_2 capture (US DOE National Energy Technology Laboratory, Nov. 2010, "Cost and Performance Baseline for Fossil Energy Plants"). Thus, newer plants burn far less coal to generate a given amount of electricity.

Table 2.1 Characteristics of Big Brown, Martin Lake, and Monticello power plants.

Facility	Year in Service	Capacity[a] (MW)	Efficiency[b]
Big Brown 1	1971	600	32.3%
Big Brown 2	1972	595	
Martin Lake 1	1977	800	32.4%
Martin Lake 2	1978	805	
Martin Lake 3	1979	805	
Monticello 1	1974	565	32.6%
Monticello 2	1975	565	
Monticello 3	1978	760	

[a]Summer capacity from [57].

[b]Computed from heat rate data for 2009 from US EPA EGRID. $Efficiency = \frac{3412\ Btu/kWh}{Heat\ Rate\ (\frac{Btu}{kWh})}$

2.4 ERCOT Forecasts

Demand for electricity in the ERCOT system has been rising as growth in the population, economy, and power-consuming devices has outstripped efficiency improvements. Electricity demand is quantified in two key ways: overall consumption and peak hourly demand. Overall consumption in the ERCOT region has grown at an average annualized rate of 1.0%/year since the turn of the century, reaching 334 MWh in 2012 [58]. Meanwhile, ERCOT peak hourly demand has grown at a rate of 1.2%/year, reaching 66,548 MW in 2012. While overall use drives trends in fuel use and emissions, it is the trend in peak demand that is crucial for determining the amount of generating capacity needed to provide a reliable supply of electricity even as meteorology, power plant availability, and other factors are constantly changing. ERCOT seeks a 13.75% reserve margin to ensure system reliability, and issues periodic forecasts for peak supply and demand to project the amount of new or replacement capacity that must be built to maintain that margin.

ERCOT's latest update, issued in December 2012, forecasts that over the next decade electric generating resources will fall increasingly short of the reserve margin that ERCOT aims to maintain beyond projected summer peak demand (Figure 2.7) [57]. Concern about this shortfall is driving efforts to promote new generating capacity and forestall the retirement of existing capacity.

However, several details of the ERCOT forecast may have accentuated the size of the projected gap. First, ERCOT in 2010 began to seek a reserve margin of 13.75%, up from the 12.5% that had been sought previously. Second, to ensure conservative forecasts, ERCOT sets strict criteria before planned new generating capacity can be included in its projections. Specifically, new non-wind capacity is considered only if it has obtained a TCEQ-approved air permit and a signed Standard Generation Interconnect Agreement or similar documentation [59]. Thus, even publicly announced new generation projects are often not included in the forecasts. The December 2012 report specifically notes three combined cycle power plants that may come on-line in 2014, as well as additional planned resources that had not progressed sufficiently for inclusion in the report [57].

Most significantly, the ERCOT report projects peak demand growing at an annualized rate of 2.7%/year from 2012-2016 before decelerating in later years. This is more than double the 1.2%/year annualized growth rate that characterized the 2000-

2012 period. It is also much faster than the 1.4%/year projected growth rate in the Texas population (Texas State Data Center, mid-range projection), despite federal regulations for lighting and appliance efficiency and more stringent building energy codes that may slow per-capita electricity demand. Nationally, there has been a downward trend toward decelerating growth in electricity demand, with projections of about 1%/year growth in the coming decades (US EIA, Annual Energy Outlook 2012).

ERCOT's prediction of a high initial growth rate leads it to project Year 2017 peak demand more than 4,700 MW larger than would occur under the historical 1.2%/year growth rate (Figure 2.8). Given its 13.75% desired reserve margin, this corresponds to more than 5,400 MW more resources sought than are likely to be needed. Coincidentally, this difference nearly matches the 5,495 MW of capacity represented by all the coal-fired units at Big Brown, Martin Lake, and Monticello combined. Over-predictions of peak demand are not entirely unexpected given the conservative nature of efforts to ensure reliability and the historical tendency of forecasts to over-predict actual peak demand. For example, our previous white paper cited ERCOT's forecast from 2008 that Year 2012 summer peak demand would surpass 70,000 MW; in fact, it was 66,548 MW.

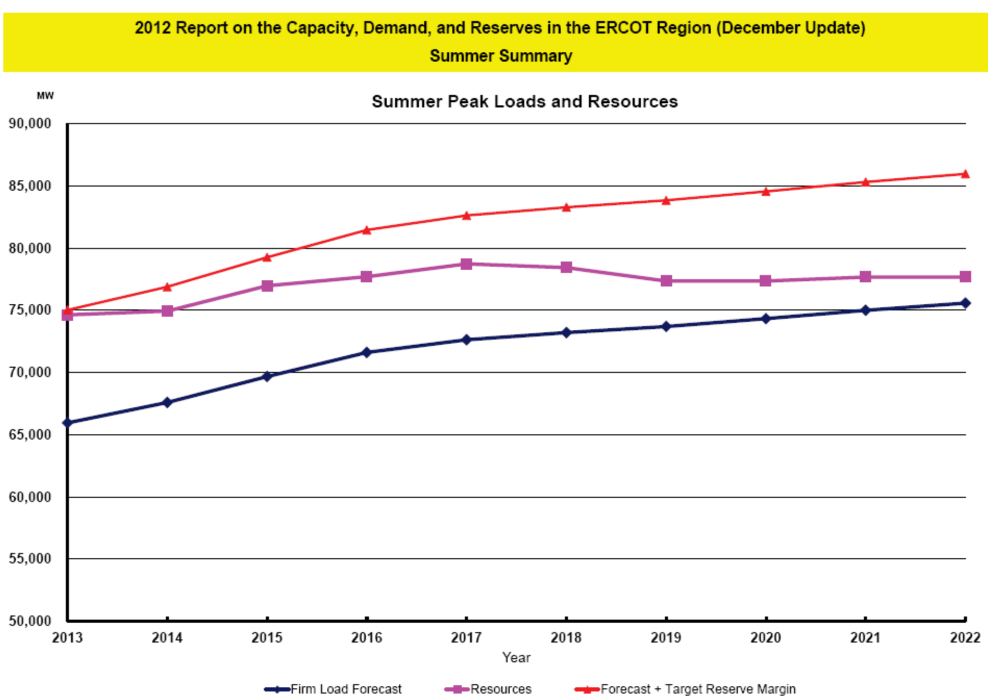


Figure 2.7. ERCOT projections of electric capacity, demand, and reserves [57]

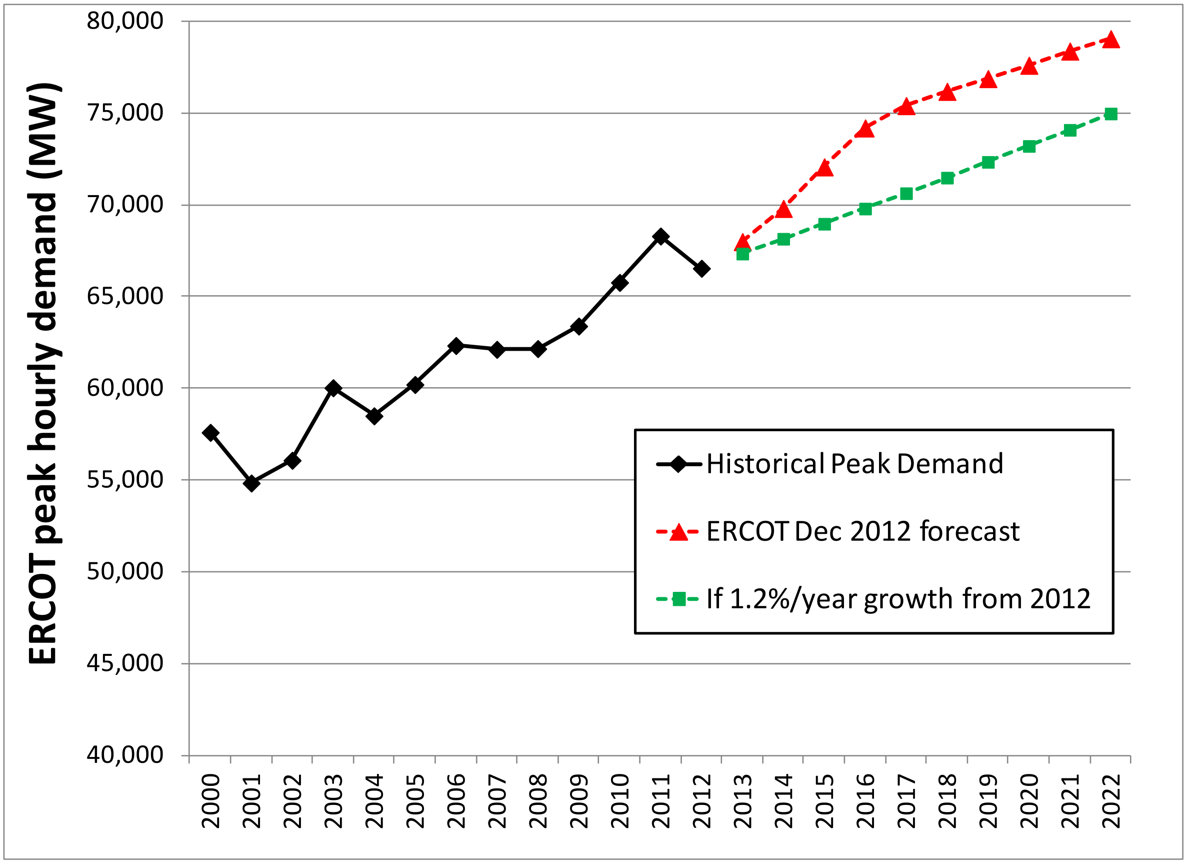


Figure 2.8. Historical trends in peak hourly demand in ERCOT, along with projections of peak demand under the ERCOT December 2012 forecast (red) or a continuation of the historically observed 1.2%/year growth rate (green).

2.5 Emissions from Coal-Fired Power Plants in Texas

Power plants, and particularly facilities that burn coal, are important emitters of the gases that form air pollution and contribute to greenhouse warming. For air pollution, the impacts of power plant plumes on ozone and particulate matter have been extensively characterized through aircraft studies and model evaluations, both in Texas (e.g., Zhou et al. 2012) and elsewhere. For climate, the CO_2 emitted from power plants contributes to a global pool of long-lived greenhouse gases.

Except for five new boilers since 2009, all of the state's coal-fired power plants came on-line between 1971 and 1992, before the most effective emissions control technologies were widely available and before emissions regulations had been tightened. The vast majority of coal-fired power plants proposed nationally over the past decade, including many in Texas at the time of our previous white paper, have never been built due to environmental and regulatory challenges and economic conditions. Thus, most coal-fired generation in the U.S. comes from decades-old facilities (Cohan and Douglas, 2011).

Of the 1971-1992 vintage coal power plants in Texas, only Parish and Sandow have been retrofit with selective catalytic reduction (SCR), the most effective control technology for NO_x,. Big Brown and Monticello control NO_x with selective non-catalytic reduction (SNCR). Most others, including Martin Lake, use only low NO_x burners and/or over-fire air for NO_x control, which is typically less effective than SCR or SNCR. Wet limestone or other flue gas desulfurization technologies are used to reduce SO_2 emissions at about half of the older facilities, including Martin Lake and Monticello Unit 3 but not Big Brown or the other Monticello units (US EPA CAMD, 2012). Control technologies for particulate matter and mercury vary, but will soon be strengthened where necessary to comply with the stringent new Mercury and Air Toxics Rule.

For ozone, power plants contribute about 9.5% of NO_x emissions in Texas and a negligible percentage of the state's VOC emissions (US EPA National Emissions Inventory 2008; Figure 1.1). Figure 2.9 shows trends in NO_x emissions from Texas power plants in the Acid Rain Program, which covers all major facilities. Although several coal power plants such as W.A. Parish dramatically reduced their NO_x emissions, the three TXU legacy facilities remained little changed, emitting over 30,200 tons of NO_x in 2011 (Figure 2.9). NO_x from these power plants has been shown to contribute to ozone in the Dallas-Fort Worth region [20] and the Waco and Tyler-Longview-Marshall regions [21] (see Section 1.1).

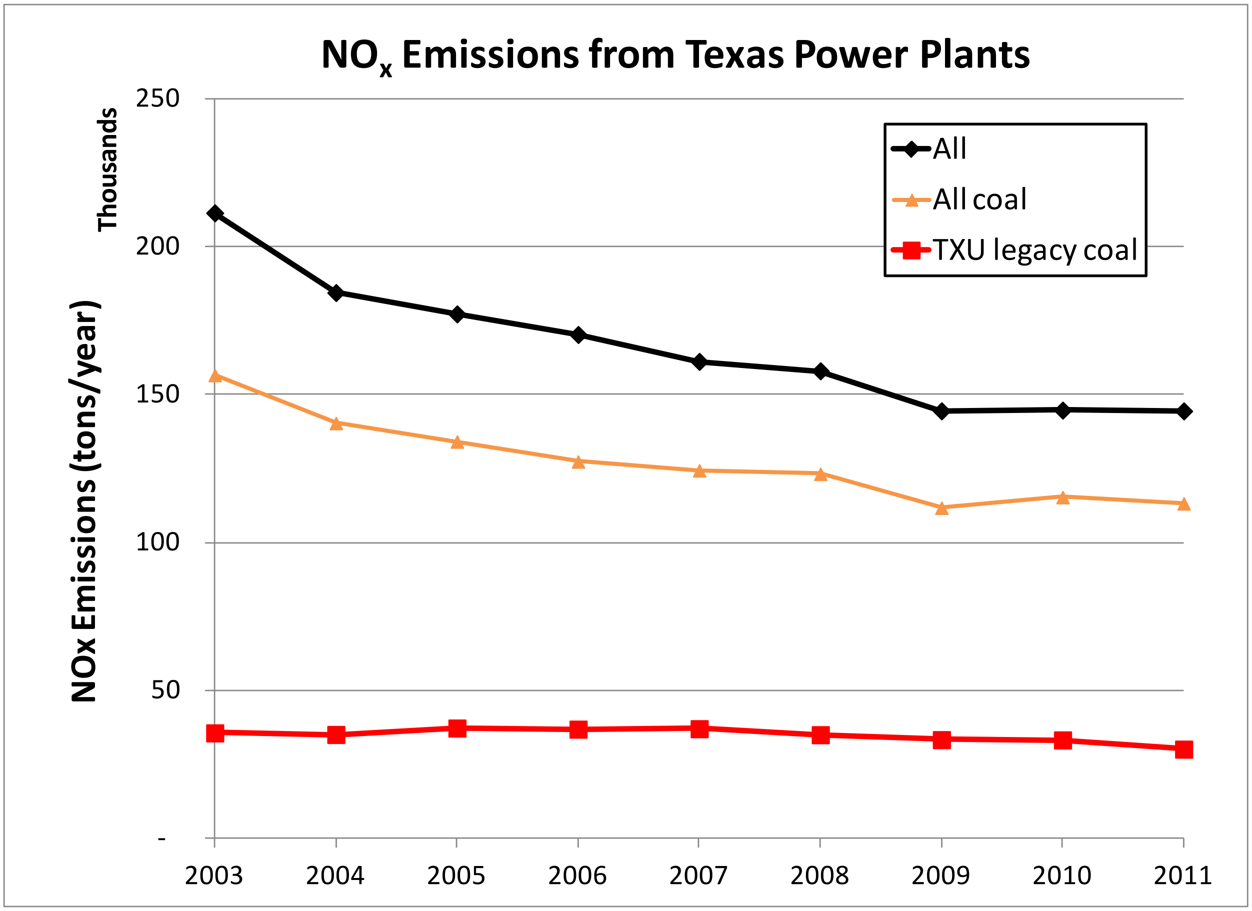


Figure 2.9. NO_x emissions from Texas power plants in the Acid Rain Program. (Data from US EPA Clean Air Markets Division)

On a per megawatt hour basis, the TXU legacy coal plants emit NO_x at rates similar to the average of other Texas coal power plants built before 1992 (Figure 2.10). However, they emit at about three times the rate of power plants built in the last decade, or of the 10 best-performing old boilers. Those include W.A. Parish near Houston, which has achieved dramatic NO_x controls from selective catalytic reduction.

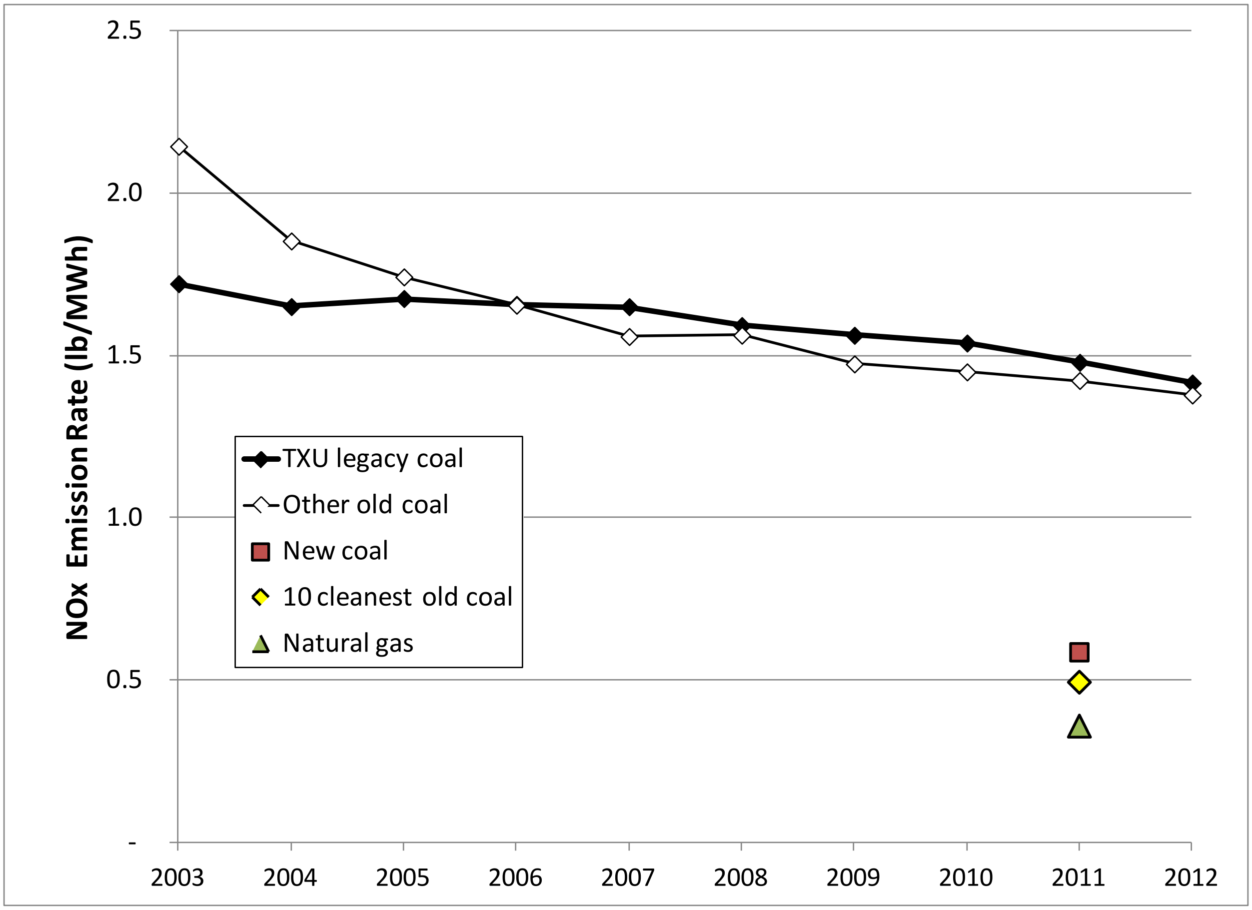


Figure 2.10. NO_x emission rates from Texas power plants in the Acid Rain Program. (Data from US EPA Clean Air Markets Division)

For the SO_2 that contributes to $PM_{2.5}$ sulfate, coal-fired power plants have long contributed the majority of emissions in Texas, and now play a dominant role as other sources have been controlled. Most other industrial sources near Houston and statewide have sharply curtailed their SO_2 emissions, as indicated by a 42% decline in SO_2 emissions within Harris County from 2005-2010 [31] and an even sharper decline statewide from 2002-2008 (Figure 2.11). On-road vehicles and off-road equipment have also dramatically reduced their emissions through national mandates for ultra-low sulfur diesel and gasoline. However, power plant SO_2 emissions in Texas have remained persistently high, declining only 26% over the longer period of available data, 2003-2011 (Figure 2.11). Most of that SO_2 is emitted from decades-old coal-fired power plants that lack the best available control devices for the gas, and nearly half is from the three TXU legacy facilities (Figure 2.11). The ammonium sulfate particles formed from

SO_2 can travel hundreds of miles downwind in power plant plumes, with impacts varying depending on wind flow and other meteorological conditions.

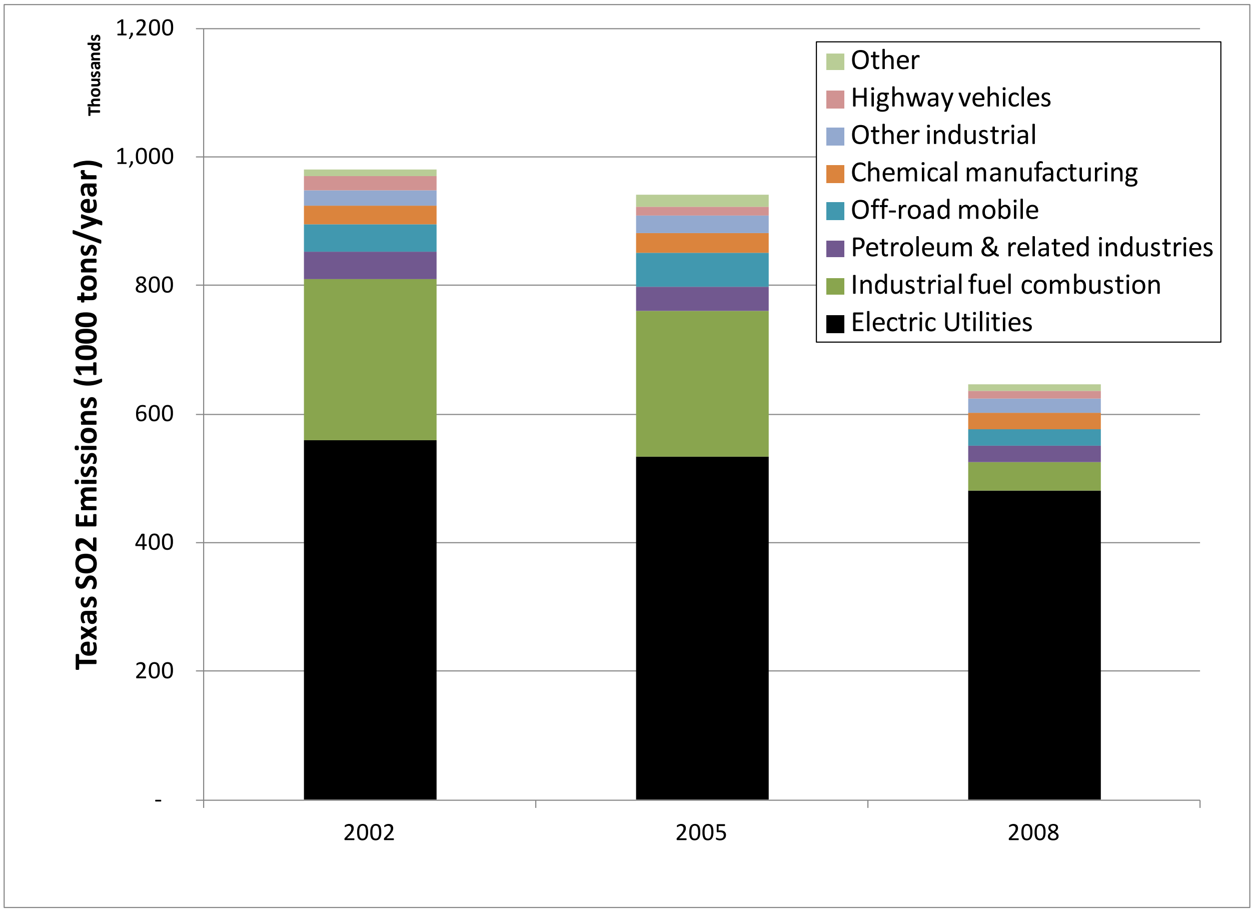


Figure 2.11. SO_2 emissions in Texas, 2002-2008. (US EPA National Emissions Inventories)

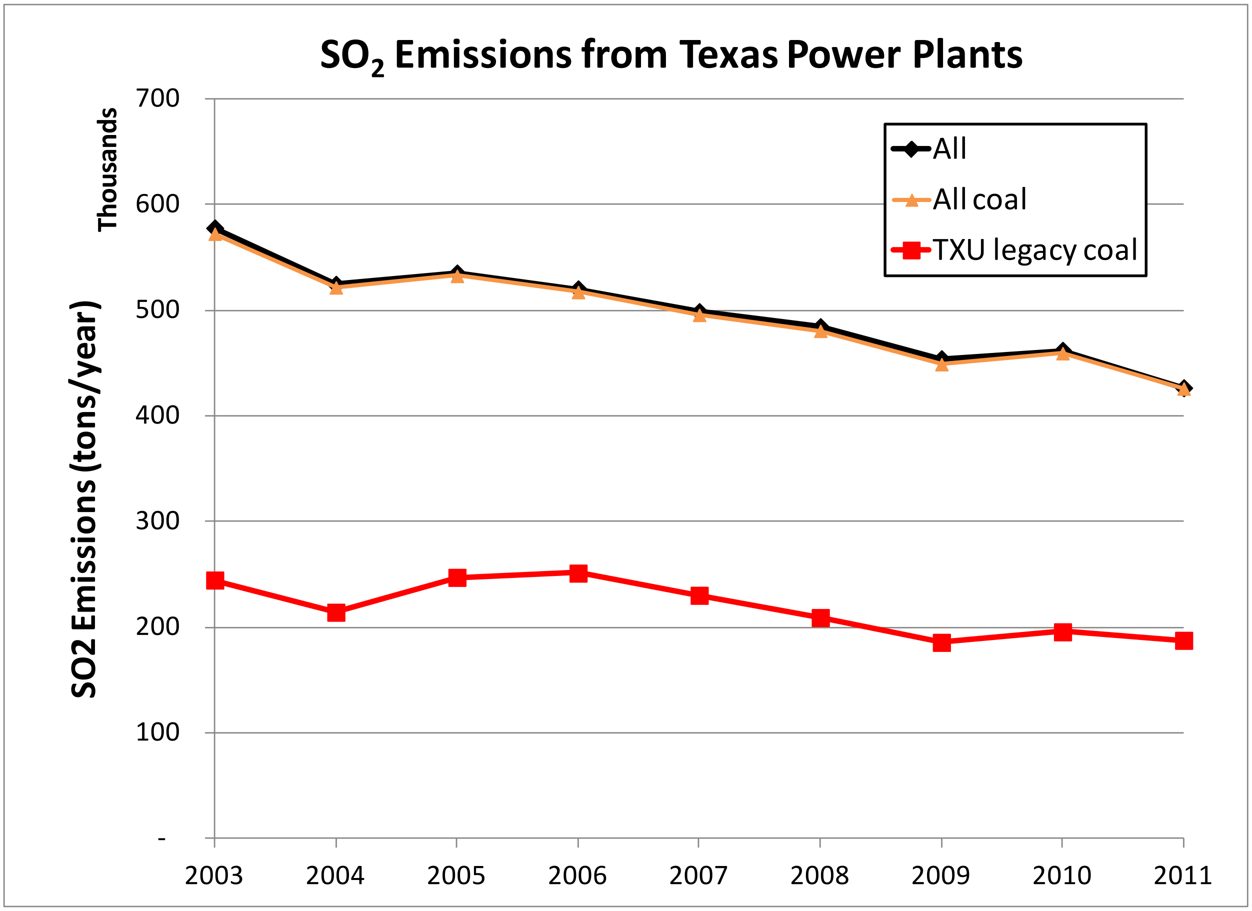


Figure 2.12. SO_2 emissions from power plants in the Acid Rain Program. (Data from US EPA Clean Air Markets Division)

Considering SO_2 on a per megawatt hour basis, Big Brown and Monticello 1 and 2 are among the highest emitting facilities in the state. Thus, taken together, the TXU legacy plants emit at almost double the rate of other old coal-fired power plants in Texas, and an order of magnitude more than the five new boilers (Figure 2.13). Several old power plants have achieved dramatic reductions in SO_2 through low-sulfur coal and/or flue gas desulfurization. Natural gas contains very little sulfur and thus contributes little to SO_2.

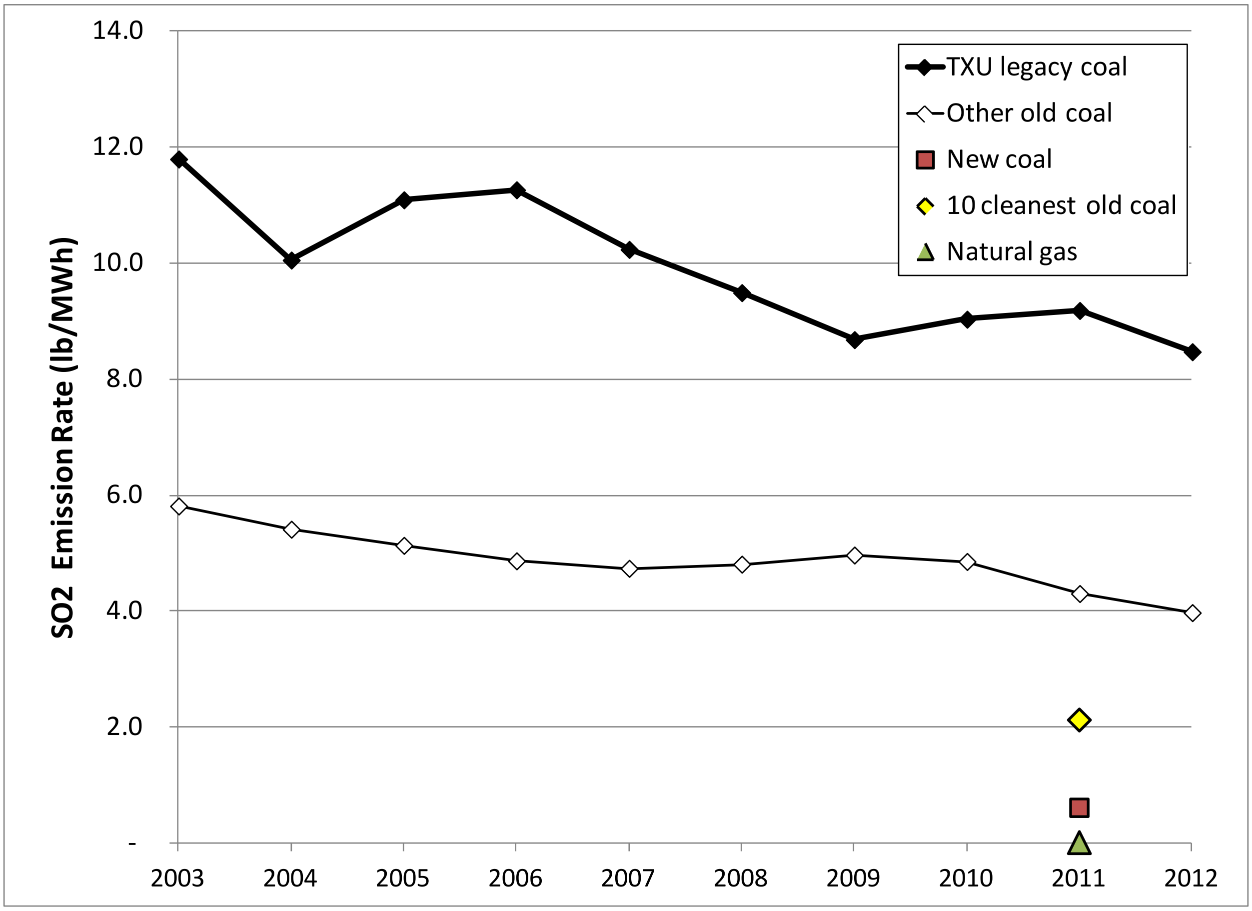


Figure 2.13. SO_2 emission rates from Texas power plants in the Acid Rain Program. (Data from US EPA Clean Air Markets Division)

Following stringent controls of mercury emissions from incinerators and municipal waste combustors, US EPA estimates that power plants now account for about half of all mercury emissions in the United States. Those emissions will be drastically curtailed by the Mercury and Air Toxics Rule issued by US EPA in December 2011. That rule requires power plants to capture 90% of their mercury emissions within four years. Unlike an earlier Clean Air Mercury Rule which would have allowed trading, the new rule requires these reductions to be achieved at all power plants.

In the most recent US EPA Toxic Release Inventory (TRI 2011), Texas led the nation in air emissions of mercury and mercury compounds, with 13,728 pounds, more than double the amount of any other state. In TRI 2011, Martin Lake, Big Brown, and

Monticello were three of the five largest emitters of mercury in the United States, emitting a total of 3,652 pounds. Taken together, this exceeds the entire air emissions of all but four other states. Installation of activated carbon injection and other control technologies, which will be needed to comply with the 90% control efficiencies required by the Mercury and Air Toxics Rule, should dramatically reduce those emissions.

For the greenhouse gas CO_2, emission rates show little variation among Texas coal power plants, since emissions are merely a function of fuel use and efficiency (Figure 2.14). CO_2 emissions are not captured by control devices, apart from pilot-scale testing at W.A. Parish (http://www.nrgenergy.com/petranova/waparish.html). The legacy TXU plants are only slightly less efficient than other old coal facilities, and actually perform similarly to boilers built in the past decade, which were not built with supercritical technologies and experience slight efficiency penalties from operating their advanced pollution control devices. Natural gas power plants emit CO_2 at about half the rate of coal power plants. These direct emission rates do not include upstream or "life cycle" emissions associated with obtaining, processing, and transporting the fuel. Accounting for those emissions, especially methane leakage, would offset some but not all of the greenhouse gas savings of natural gas relative to coal.

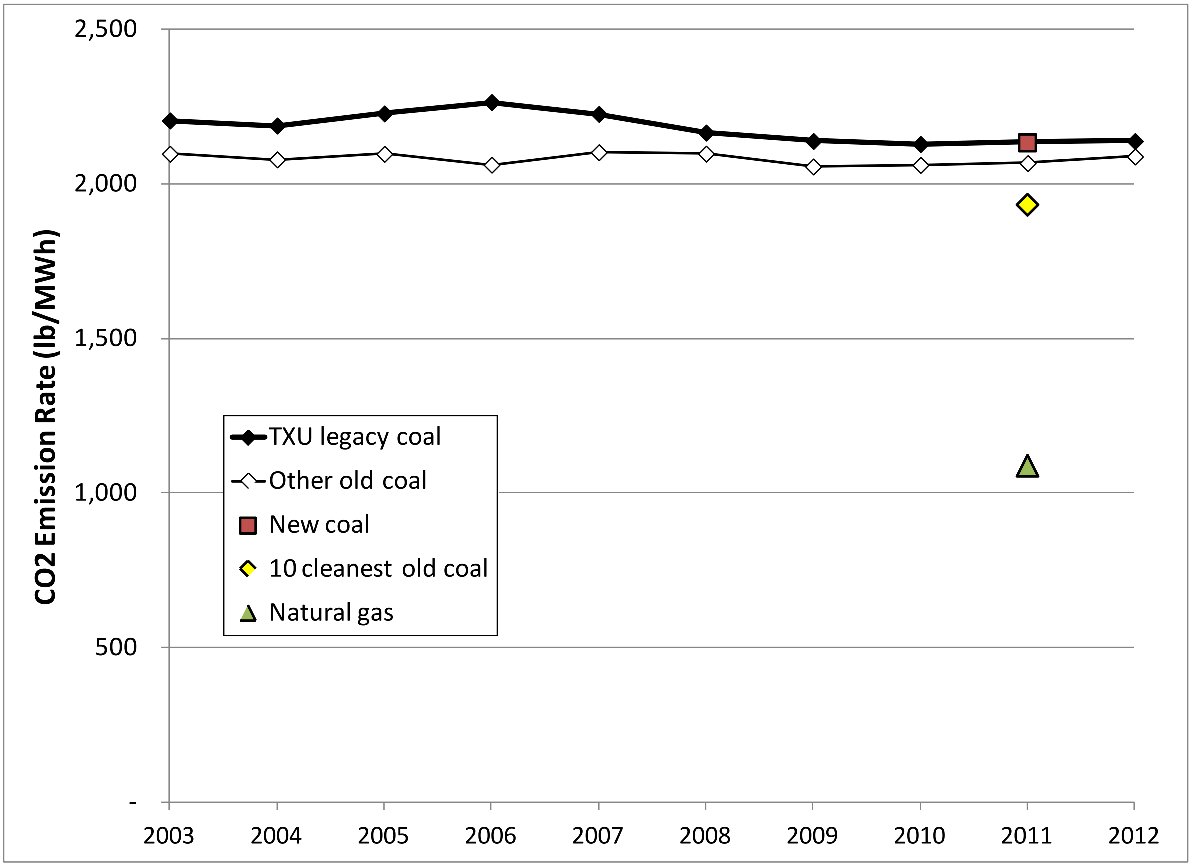


Figure 2.14. CO_2 emission rates from Texas power plants in the Acid Rain Program. (US EPA CAMD data)

Chapter 3

Options for Retrofitting or Replacing Legacy Coal Power Plants

Looking across the pollutants discussed in the first two chapters, it is readily apparent that the TXU legacy coal plants contribute an outsized share of emissions relative to their electricity output. Among all Texas power plants in the Acid Rain Program, these three facilities emit 44% of the SO_2, 21% of the NO_x, 19% of the mercury, and 16% of the CO_2, despite providing less than 12% of the state's power generation and less than 5% of its generating capacity (Figure 3.1). As the plants exceed the 30-40 year lifetime typically expected of such facilities and tightening environmental regulations add cost and complexity to their continued operation, shutting down the plants is certainly a plausible option. Some have argued that the plants have little remaining value [60], given the dampened power prices brought on by abundant natural gas and the proliferation of wind farms in the state. Despite their disproportionate impacts on the environment, the plants do provide 5,495 MW of capacity to an ERCOT market tightly balanced between supply and demand at peak times.

Thus, careful consideration is given here to two major options: 1) retrofitting emission controls on the three legacy coal plants, and 2) replacing them with alternative forms of generating capacity, including natural gas, coal, wind, nuclear, geothermal, solar, and demand response.

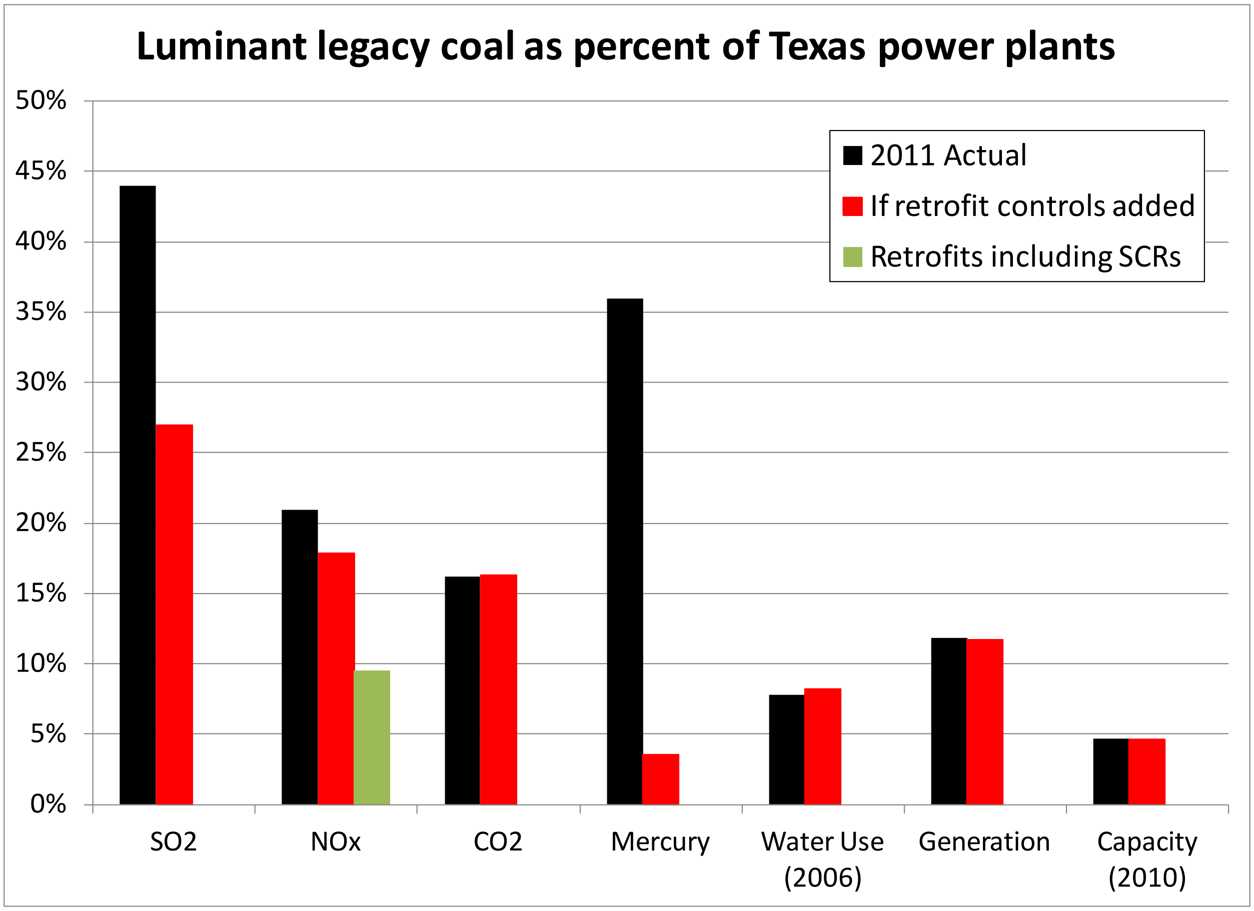


Figure 3.1. Emissions from Big Brown, Martin Lake, and Monticello as a percentage of Texas power plants in 2011 (SO_2, NO_x, CO_2, and generation (gross load) data from US EPA CAMD for Acid Rain Program facilities; mercury data from 2011 Toxics Release Inventory; water use from [61]; Nameplate capacity from US EIA, 2010; retrofit control strategy for SO_2 and NO_x based on UBS study [62] described in Section 3.1 (red), and with SCRs replacing SNCRs (green))

3.1 Option 1: Retrofit Emission Controls

Some emission control technologies are already in place at the TXU legacy coal power plants (Table 3.1), and more may be needed to comply with new EPA regulations. Baghouses and/or electrostatic precipitators (ESPs) have long been used to control particulate matter, and Luminant now uses activated carbon injection at all of its coal power plants to control mercury. Some adjustments to those injections and to the ESPs or baghouses may be needed to achieve the strict limits of EPA's new Mercury and Air Toxics Rule, according to an August 2012 analysis by UBS [62]. Like their peers, these facilities do nothing to capture CO_2 emissions, and they are unlikely to be leading candidates for such costly new technology given their age and mediocre efficiency.

Table 3.1. Emission control technologies currently in place (US EPA CAMD, 2012) and expected to be installed to comply with regulations (UBS Investment Research, 2012; in red brackets).

Facility	NO_x	SO_2	Mercury	Particulate Matter	CO_2
Big Brown 1	SNCR	[DSI]	ACI	Baghouse/ ESP	
Big Brown 2	SNCR	[DSI]	ACI	Baghouse/ ESP	
Martin Lake 1	[SNCR]	WL	ACI	ESP	
Martin Lake 2	[SNCR]	WL	ACI	ESP	
Martin Lake 3	[SNCR]	WL	ACI	ESP	
Monticello 1	SNCR	[DSI]	ACI	Baghouse/ ESP	
Monticello 2	SNCR	[DSI]	ACI	Baghouse/ ESP	
Monticello 3	SNCR	WL	ACI	ESP	

SNCR = Selective Non-Catalytic Reduction; DSI = Direct Sorbent Injection; WL = wet limestone; ACI = Activated Carbon Injection; ESP = Electrostatic Precipitator

Thus, the key question is what additional NO_x and SO_2 controls may be installed if the facilities continue to operate. Only Monticello unit 3 currently applies advanced controls for both NO_x and SO_2, and none of the units applies the most effective NO_x control, selective catalytic reduction (SCR) (Table 3.1). As noted in Chapter 1, reductions in NO_x and SO_2 emissions across eastern Texas may be critical for achieving and maintaining attainment of ambient air quality standards for ozone and $PM_{2.5}$ and protecting public health. NO_x and SO_2 controls will also become increasingly valued as cap-and-trade limits for these pollutants tighten, whether under the existing Clean Air Interstate Rule or whatever rule is developed to replace the Cross State Interstate Rule.[i]

The most effective NO_x control would be to install SCR. This technology typically achieves 90% NO_x control down to 0.06 lb/mmBtu, compared to 35% control achieved by SNCR [19]. Since the targeted boilers have already reduced their NO_x emission rates to 0.12-0.18 lb/mmBtu via low-NO_x burners and/or overfire air (US EPA CAMD data), the 0.06 lb/mmBtu floor would apply, and overall emission reduction from SCR would be 60% (18,200 tons reduction from Year 2011 emissions). Applying costing equations

[i] CSAPR was issued by US EPA in 2011 but vacated by the U.S. Court of Appeals in 2012.

from Table 5-8 of EPA IPM version 4.10 indicates that capital costs to install SCR at all 8 boilers would total $936 million.[ii] Applying EPA's assumed capital charge rate of 12%/year and adding in variable and fixed operating and maintenance costs, the annual costs of the SCRs would total $168 million/year based on Year 2011 operating conditions. This corresponds to a NO_x control cost of $9,200/ton, several times the market prices typically experienced in cap-and-trade programs. Thus, SCRs are unlikely to be installed unless specifically mandated as part of an ozone control strategy.

SNCR is more affordable though less effective than SCR, in part because it does not use a precious metal catalyst to facilitate NO_x control. An August 2012 analysis by UBS Investment Research [62] deemed SNCR at Martin Lake to be the "clear eventual retrofit" choice, matching the SNCRs already in place at Big Brown and Monticello. EPA does not model capital costs for SNCR at power plants this large, so the UBS reported cost of $35/kW is assumed [62]. This indicates that SNCR at Martin Lake would cost $85 million in capital cost upfront. Adding in fixed and variable O&M costs from the US EPA IPM model v. 4.10, annual costs would be $31 million/year (the majority for variable O&M costs), raising the cost of Martin Lake's electricity by 0.16 cents/kWh. Since only one power plant would be affected, far less NO_x emission reduction would be achieved (5,300 tons based on Year 2011 operation) than the SCR scenario, though at a lower cost ($5,900/ton).

For SO_2, UBS expects dry sorbent to be used at Big Brown 1-2 and Monticello 1-2 [62], providing a low cost option ($10/kW capital cost according to UBS) compared to the more than $400/kW typically associated with wet scrubbers (US EPA). US EPA's IPM assessments assume that dry sorbent achieves 0.065 lb/mmBtu SO_2 emissions, a 93% reduction from Year 2011 rates. Use of dry sorbent flue gas desulfurization entails a 1.3% capacity penalty and thus slightly increases CO_2 emission rates. Mercury emissions were not analyzed since all power plants will soon be capturing at least 90% of mercury to comply with the Mercury and Air Toxics Rule.

Note in Figure 3.1 that even after the UBS emission control scenario [62], the three facilities would continue to emit NO_x, SO_2, and CO_2 at rates far beyond their contribution to generation and capacity. SO_2 emissions remain high because even the boilers that already use wet limestone (and thus are not expected to install further

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[ii] Cost approximated by assuming a 1000 Btu/kWh heat rate and interpolating between the $/kW capital costs presented in the EPA Table 5-8. Cost is in Year 2007$.

controls) have emission rates near or above the state average for other old coal power plants. NO_x emissions remain high because the SNCRs achieve only 35% emission control at a single plant.

UBS estimated EFH would incur capital expenses of $364.5 million under its overall scenario [62]. Based on the 12%/year capital charge rate that US EPA typically assumes for power plant retrofit control technologies, and operating and maintenance costs from US EPA IPM simulations[iii], annualized control costs can be estimated at $137 million/year. Expressed on a per kWh basis relative to Year 2011 generation, the retrofits would add about 0.33 cents/kWh to generating costs; with SCRs, total costs of retrofits would be about 0.57 cents/kWh (Table 3.4). These amounts are substantial compared to the historically low 2.5 cents/kWh wholesale price that EFH reports for power in the North Hub in 2012 [63]. The costing assumes continuation of 2011 electricity output levels for at least 10 years; if the facilities reduce their output due to competitive pressures, as already occurred in 2012 [63], or are forced to close for regulatory or financial reasons, the costs per kWh costs could be substantially higher.

3.2 Option 2: Replacement with new capacity

3.2.1 Natural gas

In the absence of any policy initiatives, market forces are likely to lead natural gas to supply most of the new power as older facilities are retired. Most of the growth in power generation in Texas and nationwide in recent years has come from natural gas. Combined cycle power plant design allows for more efficient use of natural gas than simple cycle turbines can achieve; combined cycle technology uses the waste heat from the initial cycle to power steam cycle electricity generation. Combined cycle natural gas is readily able to meet EPA's proposed 1,000 pound/MWh limit on CO_2 from new power plants, a limit that coal and some simple cycle facilities would be unlikely to meet without costly carbon capture technologies. The figures in Chapter 2 showed the far lower NO_x and CO_2 emission rates of natural gas relative to coal, and almost no SO_2 or mercury is emitted in natural gas electricity generation. Nevertheless, natural gas generation does consume a finite resource that could be utilized for other purposes, and

[iii] For dry sorbent FGD, Variable O&M = 2.3 mills/kWh and Fixed O&M = $5.9/kW/year
For SNCR, Variable O&M = 0.98 mills/kWh and Fixed O&M = $1/kW/year
For activated carbon injection for mercury, Variable O&M = 0.017 mills/kWh for Martin Lake particulate control configuration and 0.061 mills/kWh for Big Brown and Monticello.

whose price was extremely volatile before the shale gas boom. Furthermore, though cleaner than coal, natural gas emits far more greenhouse gases and NO_x than renewable energy alternatives.

3.2.2 Coal

One possibility is that the old coal power plants could be replaced by lower emitting and more efficient new facilities burning coal. As shown in Chapter 2, the five coal-fired boilers that came online in Texas since 2008 emit far less NO_x and SO_2 than older facilities, as required to meet New Source Performance Standards. Efficiency of these boilers was not substantially better than the old ones, as reflected in the CO_2 emission rates. However, the Department of Energy's National Energy Technology Laboratory estimates that new pulverized coal supercritical power plants using existing technologies could achieve heat rates of 8,687 Btu/kWh [64], 11% lower than the 9,814 Btu/kWh average heat rate of the three legacy plants in 2011. Thus, the same amount of electricity could be generated with 11% less coal and associated CO_2 emissions and mining footprint. Despite this efficiency, such a plant would still emit about 80% more CO_2 than the proposed CO_2 limits for new power plants.

Although it has yet to be applied widely on commercial scales, carbon capture and storage (CCS) technology is generally thought to be close to operational and could be installed at new coal power plants to reduce their CO_2 emissions. However, capturing 90% of the CO_2 is expected to raise the heat rate and associated coal use to 12,002 Btu/kWh (NETL, 2010), and the levelized cost of electricity to 14 cents/kWh (EIA Annual Energy Outlook, 2013). In other words, despite its lower CO_2 emissions, such a facility would burn substantially more coal per kWh than the facilities it would replace, and cost more than natural gas (7 cents/kWh), wind, or geothermal alternatives.

Hence, a catch-22 for new coal: facilities without CCS would fail to pass EPA's proposed CO_2 emission standard, but facilities with CCS would be too costly to be economically competitive. Thus, new coal-fired generation is unlikely to be a viable option unless the cost and efficiency of CCS are substantially improved and natural gas prices rise dramatically.

3.2.3 Wind

Texas leads the nation in wind generation and capacity. Wind turbines emit no greenhouse gases or air pollutants directly, and even on a life cycle basis their emissions are only a few percent as much as fossil fuels [65]. Levelized costs of onshore wind have been estimated at 9.6 cents/kWh [66] or 5 cents/kWh (National Renewable Energy Laboratory's Transparent Cost Database data for 2012, accessed February 2013 from http://en.openei.org/apps/TCDB/), competitive with other new power providers even before accounting for incentive policies. The profitability of wind power is boosted by incentives such as the recently renewed federal production tax credit (2.2 cents/kWh for the first 10 years), which enables it to compete with existing power providers and compensates for the lower market price that non-dispatchable power such as wind often commands. However, since ERCOT multiplies wind capacity by an 8.7% availability factor in assessing summer peak resources, non-coastal wind is not a viable option for replacing large amounts of peak capacity. Examining ERCOT's daily wind integration reports coinciding with peak power demand for each of the past three years shows that a low peak availability factor is not unwarranted.

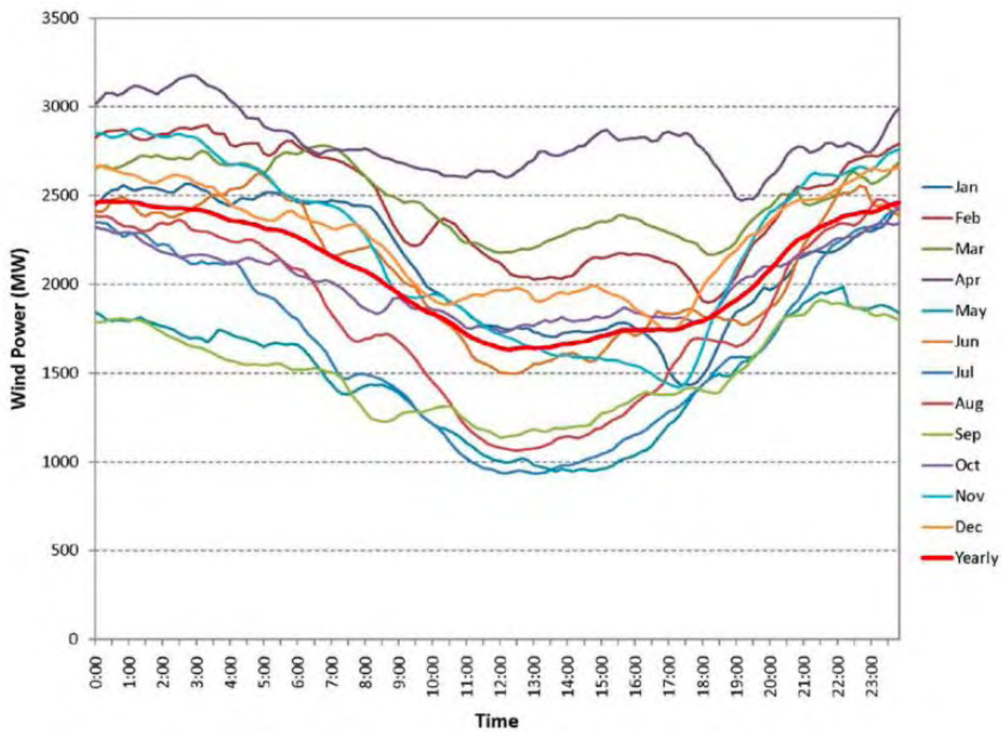
Table 3.2. Availability of wind during hour of peak demand. (Computed based on ERCOT wind integration reports and ERCOT Historical Demand and Energy Report)

Year	Time of Peak	Peak Demand	Wind availability[1]
2010	Aug. 23, 17:00	65,776 MW	7%
2011	Aug. 3, 17:00	68,304 MW	21%
2012	June 26, 17:00	66,548 MW	3%

[1]Wind availability is computed as $\left(\frac{wind\ output}{installed\ wind\ capacity}\right)$ during hour of peak demand.

Coastal wind power from onshore or offshore turbines may hold potential in providing more consistent power throughout the year, including peak periods. Coastal winds tend to blow more strongly than those elsewhere in Texas during the summer afternoons when power is needed most. Wind power in ERCOT overall reaches a minimum in the afternoons, especially during the summer (Figure 3.2, top); by contrast, coastal wind farms achieve some of their strongest output during summer afternoon sea breezes (Figure 3.2, bottom). During peak demand periods in 2011, onshore coastal turbines often achieved several times the capacity factors of West Texas turbines [67]. Coastal wind farms near Corpus Christi achieved 80% or greater capacity factors on some summer afternoons [68].

Austin Energy in January 2013 announced a deal to purchase 294 MW of wind energy from new coastal wind farms along the southern Texas Gulf coast, for just 4 cents/kWh ([69], and Austin Energy press release). This cost is in-line with the NREL estimate of wind power costs, subtracting the value of incentives, and suggests that US Energy Information Administration (US EIA) substantially overestimates the cost of wind. It is also competitive with or more affordable than other power options, indicating that coastal wind could be added to an energy portfolio without increasing costs.



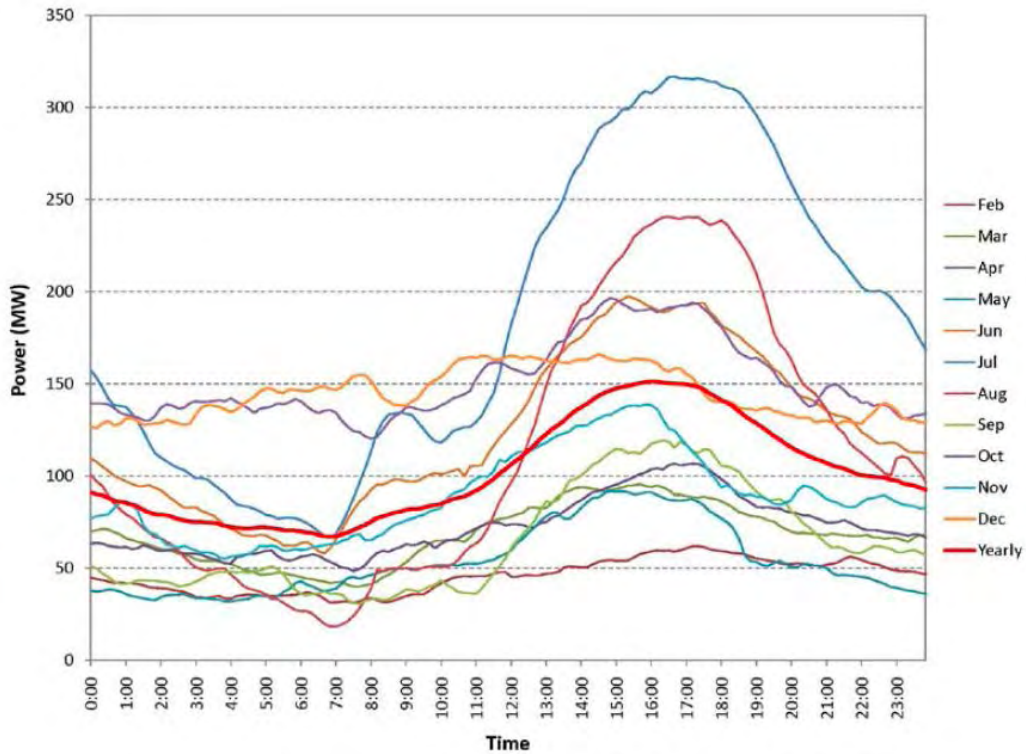


Figure 3.2. Average daily profiles of wind power in ERCOT overall (top) and from coastal turbines in ERCOT (bottom). [70]

Although most projects to date have sited turbines onshore, offshore wind turbines can achieve capacity factors of 30-40% during summertime periods of peak demand, based on an analysis of conditions along the U.S. east coast [71]. If similar conditions apply along the Texas Gulf Coast, this would be several times larger than the peak summer availability assumed by ERCOT for onshore wind. The NREL Transparent Cost Database estimates a current cost of offshore wind of 10 cents/kWh, projected to fall to 5 cents/kWh over the next five years. At its current estimate of $3,050/kW for overnight capital costs, and applying by a 30% availability factor, this implies a cost of $56 billion to build the 18,300 MW of offshore wind capacity that would be needed to replace 5,495 MW of coal capacity at peak times. While this scenario seems unlikely, a partial role for offshore wind is plausible. Coastal Point Energy seeks to build a 300 MW wind farm offshore from Galveston. Baryonyx Corporation has leased acreage for up to 1,200 MW of wind capacity off the coast of Nueces County, and two parcels off the coast of South Padre Island that could each accommodate about 1,000 MW (http://www.baryonyxcorp.com/projects.html).

3.2.4 Nuclear

Nuclear power plants provide baseload power without the high rates of greenhouse gas and air pollutant emissions associated with coal. However, according to the most recent estimates from the Energy Information Administration, new nuclear plants are expected to have a higher levelized cost of generation (11.4 cents/kWh) than natural gas, coal, wind, or geothermal [66]. Nuclear also involves very long lead times and substantial risk and uncertainty, as no new facilities have opened in the U.S. in over three decades. Most efforts to pursue nuclear and associated federal loan guarantees are occurring in regulated power markets which, unlike ERCOT, allow utilities to recoup costs plus a profit margin. A recent study by two energy research firms finds that the loan guarantees for two proposed nuclear units in Georgia could expose the federal government to billions of dollars in losses [72]. Furthermore, no long term plan has been developed for permanent storage of radioactive wastes from nuclear plants. In sum, nuclear power is unlikely to be a viable option to replace retiring coal generation capacity.

3.2.5 Geothermal

Geothermal power plants utilize energy from within the Earth to generate electricity. Improving technology has brought geothermal close to achieving cost parity with other options for new electric generation capacity. Maria Richards at Southern Methodist University and Bruce Cutright at the University of Texas Bureau of Economic Geology have extensively studied potential geothermal resources in Texas and associated costs.

A key determinant of a region’s suitability for geothermal power is the geothermal gradient, which measures how quickly temperatures increase with depth underground. Based on geothermal gradients and the permeability of reservoirs, Texas has far more geothermal resources than would be needed to supply the 5,495 MW of capacity targeted here (B. Cutright, personal communication). Many of the best prospective sites are located within the same quadrant of Texas as the Luminant facilities (Figure 3.2), and are expected to support operating lifetimes of 20-30 years. Cutright estimates a cost range per installed megawatt of \$2.5 - \$3.2 million/MW, with \$2.7 million/MW representing a realistic cost for replacing some of the capacity and \$3.0 million/MW to replace the entire amount. EIA Annual Energy Outlook 2013 estimates a slightly lower capital cost for geothermal, \$2.51 million/MW. Thus, full replacement of the 5,495 MW of capacity would cost $13.8-16.5 billion. However, that cost could be readily recovered, given estimates that levelized costs of electricity (including upfront capital costs) would be 6-9 cents per kWh at several prospective geothermal sites (Table 3.2). Other sites that may require deeper drilling or fracking could entail slightly higher levelized costs of 10-11 cents/kWh (B. Cutright, personal communication). In any event, geothermal clearly has the potential to be competitive with the levelized costs of new electricity generation from natural gas combined cycle (7 cents/kWh, or 9 cents/kWh with carbon capture and storage (CCS)), wind (9 cents/kWh), and coal (10 cents/kWh, or 14 cents/kWh with CCS) (US EIA Annual Energy Outlook 2013). Its profitability is further enhanced by a federal production tax credit of 2.2 cents/kWh for the first 10 years of operation, or by a 30% federal Business Energy Investment Tax Credit. Geothermal also has competitive advantages by avoiding the greenhouse gas emissions and fuel price volatility of natural gas, and by being dispatchable, allowing it to command higher prices and better serve peak power needs than wind.

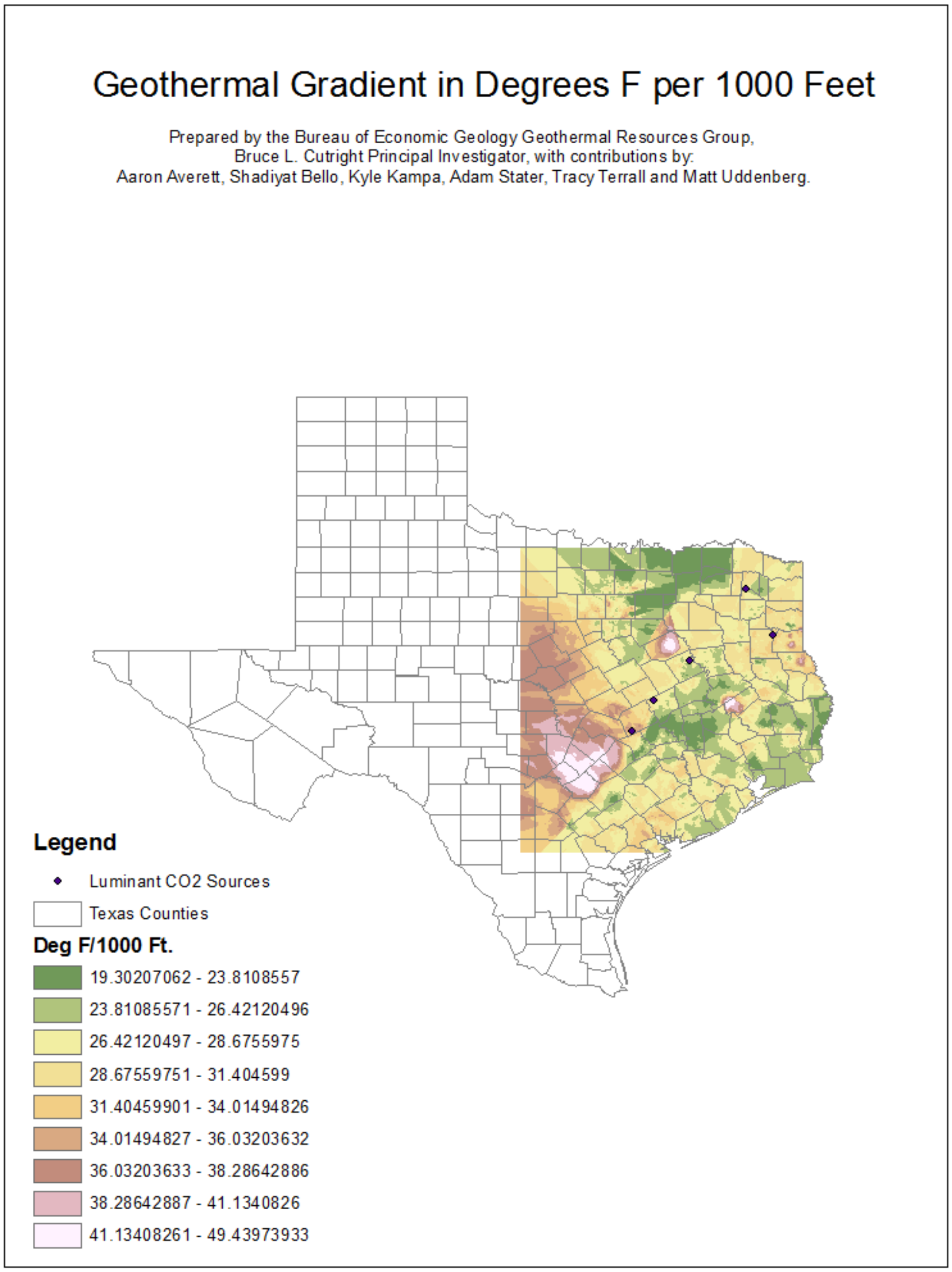


Figure 3.2. Geothermal gradients in eastern Texas. (Bruce Cutright, University of Texas Bureau of Economic Geology)

Table 3.3. Levelized cost estimates for geothermal electricity production from potential sites in Texas. (Bruce Cutright, University of Texas Bureau of Economic Geology)

	Levelized Cost of Electricity Production (Using DOE GETEM Model)		
	Optimistic Case	Base Case	Conservative Case
Geologic Basin	Cents per Kilowatt-Hour		
Will-O Field, West Texas	6.65	8.4	10.25
South Hidalgo Fairway, Gulf Coast	5.28	6.52	10.34
Brachfield Southeast, East Texas	5.98	7.06	8.71
Mathers Ranch Field, North Texas	6.34	8.46	11.11

3.2.4 Solar

Like wind, solar power emits no air pollutants or greenhouse gases, and even on a life cycle basis its carbon footprint is only a tenth that of natural gas [65]. Prices of solar power have fallen dramatically in recent years, but remain above the level of most other options before incentives are taken into account. US EIA Annual Energy Outlook 2013 estimates a levelized cost of 14.4 cents/kWh for solar photovoltaics (PV). This is consistent with Solarbuzz estimates of 15.2 cents/kWh for an industrial scale system (Solar Electricity Index, March 2012). However, these estimates do not account for any of the financial incentives available to solar, which can reduce project costs by more than 50 percent. Industry insiders suggest that Texas power providers can now purchase solar for roughly 7.5-8.0 cents/kWh. This is consistent with the 5.8 cents/kWh price of a power purchase agreement between El Paso Electric and Element Power for the 50 MW Macho Springs Solar Project [73], which includes 2-4 cents/kWh of performance-based incentives from the state of New Mexico [74].

Solar PV in Texas could be expected to achieve a summertime capacity factor of about 47% at 5 pm, the time when peak demand typically occurs in ERCOT, according to a Brattle Group study using NREL's Solar Advisor Model [75]. Thus, about 11,700 MW of solar PV capacity would be needed to replace 5,495 MW of coal at peak times. Based on NREL estimates of an installed cost of industrial-scale solar PV of $3,383/kW [76], this would imply an upfront capital cost of about $40 billion. However, federal policy provides a 30% Business Energy Investment Tax Credit for solar, and favorable treatment of depreciation. Thus, actual costs to utilities and ratepayers in Texas would be far lower, possibly in the range of $25 billion.

3.2.5 Demand Response

Demand response refers to efforts to curtail electricity use specifically at times of peak power demand or high power prices, either by reducing consumption or shifting it to off-peak periods. Demand response can be achieved by asking customers to turn off equipment, by asking customers to turn on on-site generators, or by using thermal storage technologies, which allow building air conditioning needs to be met with stored chilled water produced by electric chillers operating at night. Advanced electric meters (or smart meters) already installed throughout much of ERCOT can enable real-time pricing and communication with the utility, reducing waste and improving peak-load management. Real-time metering and pricing help consumers monitor and modify their behavior during peak hours if pricing plans become tied to time of day. Demand response can be a powerful way to ensure system reliability and performance and can minimize the need for costly new generation facilities. The American Council for an Energy-Efficient Economy (ACEEE) has estimated that enhanced demand response efforts could reduce peak demand in Texas by 13% [77], far more than needed to offset the entire 5,495 MW targeted here.

ACEEE estimates that demand response can reduce peak demand at a cost of only $46 per kW, since its impacts are directly targeted at peak periods. This would correspond to just $253 million, far less than most of the options considered above. However, it would not substantially affect annual electricity generation if demand is merely shifted to other hours. Impact on emissions would depend on the mix of facilities providing electricity at peak and off-peak times.

Another advantage of demand response is that many potential measures could be implemented far more rapidly than new power generation, which requires substantial lead time for permitting and construction. This feature of demand response may prove crucial in alleviating the tight balance between supply and demand before new generation capacity comes online.

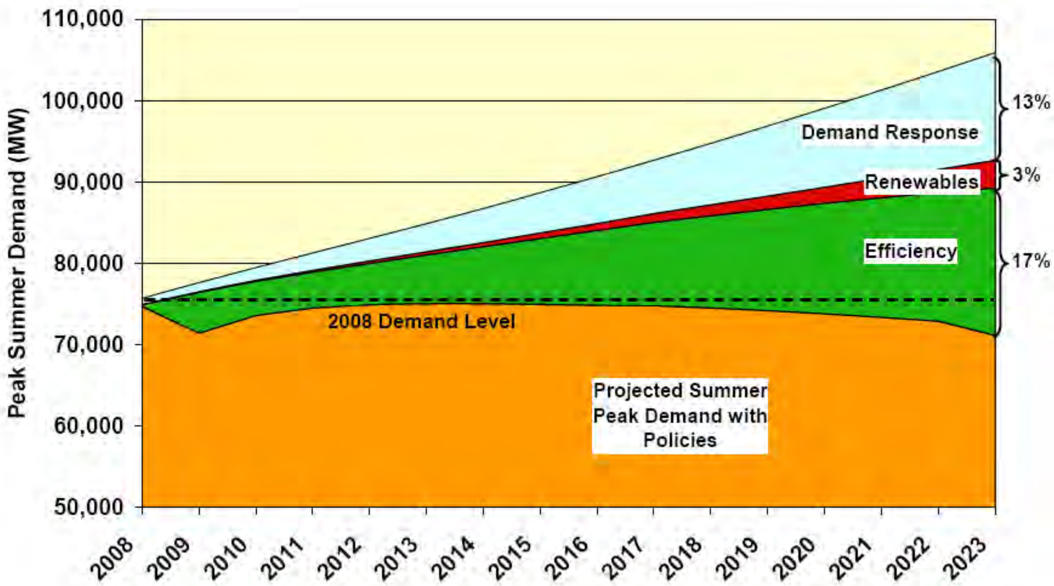


Figure 3.3. Fraction of summer peak demand that can be met with demand response, efficiency, and renewable resources. (American Council for an Energy Efficient Economy)

3.3 Synthesis of Options

Looking across the retrofit and replacement options, we can compare the costs and environmental impacts on a per MWh basis (Table 3.4). Continuing to operate the coal power plants, even with the costs of pollution retrofits, provides the cheapest electricity, though the differential relative to natural gas, geothermal, and coastal wind is slight, especially once federal incentives are considered. However, this is not the case if health and climate costs are considered, as emissions of SO_2, NO_x, CO_2, and mercury would all be substantially higher than for natural gas, and orders of magnitude higher than for the renewable energy options. The renewable energy options also use much less water, which could become important in drought years.

Continuing to operate the coal power plants also faces the financial risk that may result from future policies to control CO_2. A hypothetical CO_2 price of just \$25/ton, along with existing federal tax incentives for renewable, would erase the cost advantage of retrofit coal relative to geothermal, coastal wind, and even solar. It would also erase the cost advantage of natural gas relative to renewable options. This is before assigning any value to the higher air pollutant emissions and water use of fossil fuels relative to renewables, or to the risk of potentially higher natural gas prices in the future. While future federal CO_2 policies cannot be predicted over the multi-decade lifetime of power generation facilities, this hypothetical CO_2 price of $25/ton is toward the low end of the $0-$100/ton range that ERCOT considered in evaluating the impacts of potential allowance prices [78].

Energy efficiency and demand response would provide the lowest cost replacements for replacing peak power capacity. Based on the 3.5 cents/kWh cost estimate of ACEEE for available options in Texas [77], investments in energy efficiency would be the lowest cost approach to replacing power generation (Table 3.4). Demand response cannot be directly compared to the other options in Table 3.4 on a per MWh basis, since it may in part shift the timing of use rather than reducing overall consumption. However, the strong cost-effectiveness of demand response investments – $46/kW versus thousands of dollars per kW for the other options – suggests that demand response should also be pursued to the fullest extent possible.

Table 3.4 Costs and emissions per 1 MWh of electricity from retrofit and replacement options.

	Cost[1]	Cost with incentives[2]	Cost with incentives + $25/ton CO_2 [3]	SO_2 [4] (lb)	NO_x [5] (lb)	CO_2 [6] (lb)	Hg [7] (10^{-5} lb)	Water use [8] (gal)
Legacy coal 2011	$39.63	$39.63	$66.34	9.18	1.48	2,137	8.9	300
Coal with UBS retrofits [9]	$42.89	$42.89	$70.02	4.36	1.23	2,170	0.9	309
Coal with SCRs [10]	$45.29	$45.29	$72.42	4.36	0.59	2,170	0.9	309
Natural gas	$65.90	$65.90	$79.51	0.01	0.36	1,089	0.0	270
Geothermal	$76.10-$88.20	$65.10-$77.20	$65.65-$77.75	0.17	0.00	44	0.0	5
Coastal wind	$51.00-$83.40	$40.00-$72.40	$40.00-$72.40	0.00	0.00	0	0.0	1
Solar	$140.30	$77.90-$101.18	$77.90-$101.18	0.00	0.00	0	0.0	26
Energy efficiency	$35.00	$35.00	$35.00	0.00	0.00	0	0.0	0

[1]Costs from EIA Annual Energy Outlook 2013, neglecting transmission costs. Coal costs include EIA's assumption of $22/kW/year capital costs for repairs and maintenance. Lower end of geothermal range is estimate from Bruce Cutright, UT-Austin. Lower end of coastal wind is based on $40/MWh price reportedly paid by Austin Energy, adding back in $11/MWh from the federal production tax credit. Energy efficiency cost estimate from [77].
[2]Applies $22/MWh federal production tax credit (PTC) for geothermal and wind, and 30% federal tax credit on capital costs for solar. Federal PTC is discounted by 50%, since it is available only for 10 years. For solar, lower price is the rate paid by El Paso Electric for power from the Macho Springs Electric Project [73], removing the incentives from the State of New Mexico [74]; upper price applies a 30% tax credit to capital costs in the EIA estimate.
[3]This represents the median scenario considered by ERCOT for potential federal CO_2 policies [78]; the seven scenarios spanned a range from $0-$100/ton CO_2.

[4]Coal and natural gas emissions from US EPA CAMD data for Texas in 2011. Retrofit emissions based on dry sorbent achieving 0.065 lb/mmBtu SO_2 emissions [19]. Geothermal is midpoint of range reported by Geothermal Energy Association.
[5]Coal and natural gas emissions from US EPA CAMD data for 2011. Retrofit emissions based on SNCR achieving 35% capture, and SCR achieving 0.06 lb/MMBtu, from US EPA IPM assumptions.
[6]Only direct emissions are shown, neglecting upstream emissions such as methane leaks or manufacture of power generating equipment. Coal and natural gas emissions from US EPA CAMD data for 2011. Geothermal from Geothermal Energy Association.
[7]Coal emissions from EPA CAMD data for 2011. Assume 90% capture under Mercury and Air Toxics Rule. Electricity generation from other fuels does not generate substantial amounts of mercury.
[8]Coal and natural gas estimates from King et al (UT-Austin), 2008. Geothermal from Geothermal Energy Association. Wind from MIT study. Solar from NREL study.
[9]Retrofit assumptions from UBS Investment Research 2012 scenario, which includes dry sorbent for SO_2 and SNCRs for NO_x.
[10]Retrofit controls from UBS 2012 scenario, but with SCRs instead of SNCRs.

Chapter 4

Policy Options

The preceding chapters have characterized the air quality and electricity challenges in Texas and the role of the legacy TXU coal-fired power plants. Whether and how the facilities are retrofit, retired, or replaced has important consequences for air quality and electric reliability in Texas. Most of those decisions will reside with the private sector and market forces. However, this chapter considers policy options that might improve the likelihood of favorable outcomes for Texas.

4.1 Disincentivizing High-Emitting Power

Chapters 2 and 3 clearly demonstrated the outsized role of the TXU legacy coal power plants in pollutant emissions and water use relative to their electric generation and capacity. Perpetuating that situation with incentives or interventions would be ill-advised. The power plants already benefit from key competitive advantages, with capital costs already paid and far less stringent emission requirements than any new facility would face. Chapter 3 showed that an array of options is available for replacing the peak power provided by these plants via natural gas, geothermal, solar, coastal wind or demand response. If the facilities do continue to operate, Chapter 3 showed that control technologies are available to substantially reduce emissions at costs of less than 1 cent/kWh.

One approach to help ensure lower emissions from legacy power plants would be to tighten emission limits. The 1999 bill deregulating Texas power markets set limits on NO_x and SO_2 emissions from power plants in east Texas (Texas utilities code section 39.264). Emission control technologies have improved substantially since then, and new power plants are now held to far more stringent standards nationwide. More stringent emission limits for existing facilities would be achievable and would reduce their air pollution impacts.

4.2 A Viable Market for Low-emitting Power

Despite the need for new peak power generating capacity in ERCOT and the air quality advantages of low-emitting options, new providers of renewable energy face key challenges that could be eased. The earlier discussion showed that geothermal, solar, and coastal wind are all capable of contributing to peak power needs at competitive costs once federal incentives are factored in. However, even projects with favorable costs are facing difficulty obtaining financing, because the short-term nature of Texas power markets and wholesale contracts clouds the predictability of future revenue. Unlike their natural gas competitors, renewable energy projects incur the vast majority of their costs as upfront capital, so financing availability and costs are especially critical.

Some of the steps taken by ERCOT to encourage new peak generation have raised costs to consumers with little benefit to potential new renewable energy providers. For example, raising the cap on spot market electricity prices provides occasional windfalls to existing peak power provider, but does little to clarify the revenue outlook of new facilities that are seeking funding. New generation capacity from solar and other renewable sources could ease the balance between supply and demand, potentially bringing down overall costs to consumers by more than the upfront costs of the new capacity while substantially reducing emissions [75]. The current system fails to incentivize these benefits that renewable generation can provide.

4.3. Renewable Portfolio Standards

Renewable portfolio standards (RPS) set a target for electricity from renewable sources and use market trading of renewable energy credits (RECs) to meet that goal. When Texas first established its RPS program in 1999 [79], it was the largest program of its kind in the nation and the first to track compliance using tradable RECs. A national review of RPS programs in 2004 [80] found Texas to have the most successful program in the country, noting the success of the REC trading market and crediting the program for catalyzing the tremendous growth in wind power in the state. Texas achieved its original RPS targets four years ahead of schedule, and in 2005 Senate Bill 20 increased the renewable energy mandate to 5,880 MW by 2015, with a target of 10,000 MW by 2025.

Despite the success and expansion of the Texas RPS, many states have now leapfrogged ahead of Texas to enact more aggressive RPS requirements. Twenty-nine states have now implemented RPS programs, many of them seeking to obtain 10-40% of electricity from renewable sources (Database of State Incentives for Renewables and Efficiency; Figure 4.1). By contrast, the 2015 Texas RPS is equivalent to just 5% of capacity and has already been surpassed. A low RPS mandate diminishes the value of the tradable RECs that incentivize renewable energy generation. The Union of Concerned Scientists estimates that a more aggressive 20% target would lead to billions of dollars in electricity savings, significant job creation, and large reductions in power plant emissions [81].

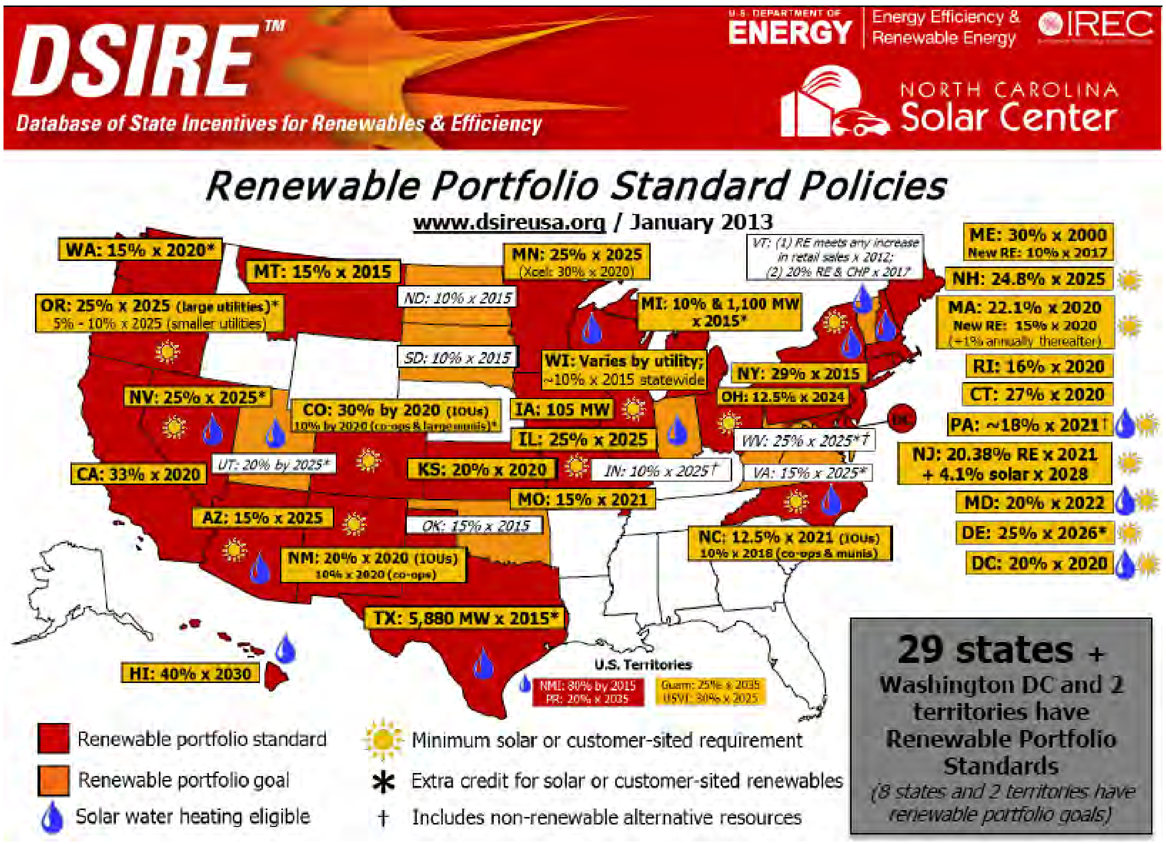


Figure 4.1 Renewable Portfolio Standards as of January 2013 (DSIRE).

Since Texas like many states sets its RPS based on installed capacity, it is not ideally suited for promoting renewable energy sources that would provide large amounts of peak capacity. Almost all of the Texas RPS was satisfied with on-shore wind power. As noted in Chapter 3.2.3, ERCOT multiplies wind capacity by an 8.7% availability factor to assess its contribution to peak resources. A peak power renewable portfolio standard could incentivize providers such as geothermal that are better suited for supplying reliable and dispatchable power during peak time periods. Credit could also be given to solar power, which generally achieves capacity factors of 40-50% during peak hours. An analysis by the Brattle group found that, by alleviating the tight balance between supply and peak demand, new generation from sources such as solar can reduce overall costs to electricity consumers [75].

Another key step to promoting non-wind renewable energy sources like geothermal and solar is to follow through on a provision already written into state law but never implemented. The law that created the state's RPS tasked the Public Utility Commission (PUC) with establishing a target of at least 500 MW capacity from non-wind renewable energy technologies. However, PUC has yet to establish this non-wind target. White Camp Solar of Houston says that the lack of the mandated non-wind RPS has stifled its ability to finance a planned 100+ MW solar farm near Lubbock, and that RECs from a non-wind RPS would provide revenue crucial to the financial viability of such projects [82]. A non-wind RPS at or beyond the intended 500 MW minimum would help Texas solar and geothermal developers tap into the federal incentives already available for such projects, and better utilize the new transmission capacity already being built for the state's competitive renewable energy zones. It would also promote the development of renewable sources that are better suited than inland wind for generating electricity at periods of peak demand.

4.4 Energy Efficiency Portfolio Standards

Senate Bill 7 of 1999 established a utility energy efficiency improvement program, also known as an energy efficiency portfolio standard (EEPS). The provision required investor-owned electricity utilities to meet 10% of their annual growth in demand by energy efficiency measures. With electricity demand growing by about 2% per year, this provision was equivalent to reducing energy demand by about 0.2% annually. Utilities must contract with outside energy efficiency service providers to implement these measures, and may provide incentives to consumers for energy efficiency measures. In 2007, House Bill 3693 increased the energy savings requirement to 20% of annual residential and commercial demand growth but omitted the industrial sector [83]. In 2011, Senate Bill 1125 increased the energy efficiency goal to 30% of load growth for investor-owned utilities, and shifted the target to focus on peak demand rather than overall demand [84].

The energy efficiency measures have proven to be highly successful and to have achieved benefits that far outweigh the costs. The Public Utility Commission of Texas found that measures enacted in 2005 alone saved 500,000 MWh of electricity annually, exceeding the goal by 27%, and that the $78 million spent by utilities that year will result in $290 million in energy cost savings, a return on investment of nearly four-to-one [85]. Measures enacted in the first four years resulted in about 2,700 tons of cumulative NOx reductions [86]. The format of the program ensures that results are verified by independent third parties and creates a market for energy efficiency services and associated jobs.

Given the success of the existing provisions, could the state adopt a more ambitious target for energy efficiency measures? Abundant evidence suggests that much greater energy savings could be achieved by utility programs. The ACEEE has estimated that an expanded utility energy efficiency program could offset 40-50% of projected growth in Texas electricity demand [77]. Likewise, the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy estimates that 40-50% of the nation's electricity load growth could be displaced through energy efficiency, pricing reforms, and load management. California and Connecticut each require utility programs to achieve electricity savings of about 1% per year [87], more than double the Texas target. Nationwide, demand-side management programs by utilities achieved 59.9 million MWh of total energy savings in 2005 [88], several times larger on a per-capita basis than Texas achieved.

Raising the requirements of the Texas program would greatly increase energy savings, reduce emissions, and avert some of the need to construct new power plants. More importantly, such a policy would yield savings to consumers that would far exceed its costs. ACEEE recommends expanding the utility targets to 50% of demand growth, resulting in 28.5 billion kWh of annual electricity savings and 9400 MW of peak demand reduction by 2023 compared to a 10% standard [77]. Many of the measures currently funded by utilities to meet their EEPS requirements, such as weatherization of low-income homes, could be greatly expanded if the requirements were strengthened.

Beyond strengthening the energy savings target, other modifications could enhance the program's effectiveness. The energy efficiency mandate currently applies to regulated investor-owned utilities that supply about 80% of Texas electricity sales [77]; the program could be expanded to encourage other electricity providers to participate in the program. The state could also loosen caps on the utility-paid portion of each measure in order to enable a wider array of measures to be implemented.

A challenge to the success of utility-based programs is that utilities profit by selling electricity, and thus face a disincentive to exceed their energy savings targets. Although energy efficiency generally costs less than building new capacity, more could be done to properly align utilities' incentives to implement efficiency measures and exceed their mandated levels. One potential approach would be to establish tradable Energy Efficiency Credits (EECs), akin to the RECs that accompany the state's Renewable Portfolio Standards (RPS) program. EECs would be provided for measures that reduce energy consumption, and each utility would be responsible for a certain level of EECs based on their electricity sales. A tradable credit system would enable utilities to profit by exceeding their energy savings targets. It would also allow more ambitious energy savings targets to be achieved while minimizing costs because the market-based approach would encourage implementation of the most cost-effective measures needed to achieve the overall goal.

4.5. Conclusions

The legacy coal-fired power plants exert influences on air pollution, climate, and water use far beyond their contribution to the state's electricity. While retrofit control devices could somewhat reduce their emissions of air pollutants, emission rates would remain far above what alternatives could achieve, and impacts to climate and water use would continue unabated. Thus, replacement of the power plants with cleaner sources of electricity must be considered.

Natural gas, geothermal, coastal wind, solar and demand reduction all have the potential to replace the generation and peak power capacity from the legacy coal power plants with far lower impacts to the environment. Costs of these options to Texas ratepayers are likely to be highly competitive with each other once federal incentives are taken into account. Each may serve as a least cost provider under certain circumstances depending on a variety of factors such as future natural gas prices; solar and geothermal conditions at specific sites; improvements in technology; and future federal policies for carbon emissions and renewable energy incentives. However, current market conditions in ERCOT, including highly variable and unpredictable power prices and lack of incentives for new and renewable generation, are hindering investments in new generating capacity and demand response. Any of the above policy approaches could help close the projected gap between peak demand and supply in

ERCOT at manageable costs while alleviating the environmental burdens of power generation in Texas.

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