Synapse
Energy Economics, Inc.

Beyond Business as Usual

Investigating a Future without Coal and Nuclear Power in the U.S.

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Prepared for the Civil Society Institute

Prepared by:
Geoffrey Keith, Bruce Biewald, Kenji Takahashi, Alice Napoleon, Nicole Hughes, Lauri Mancinelli, and Erin Brandt

22 Pearl Street
Cambridge, MA 02139
www.synapse-energy.com
617.661.3248

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1. Introduction

The electric power industry in the U.S. is at a crossroads. Many of the nation's generating plants are over forty years old and in need of upgrades to continue operating efficiently. The transmission grid is also in need of reinforcement and expansion. At the same time, the risks associated with climate change are forcing us to consider quantum shifts in the way we generate and use electricity.

Some proposals to address climate change assume that because coal is relatively abundant in the U.S., it must play a key role in our electricity future. Typically, these proposals include massive investment to develop technologies to decarbonize coal and/or remove CO_2 from coal combustion gases. Similarly, many proposals assume that because nuclear generation does not emit CO_2 directly, additional nuclear plants must be a part of the solution. This assumption has led to new subsidies and large government loan guarantees designed to revive the U.S. nuclear industry.

However, coal and nuclear power come at a high price. New rules enacted to protect public health will require billions of dollars in new emission control equipment at old coal-fired plants. These controls would reduce SO_2, NO_x, and mercury emissions but would do nothing to reduce CO_2 emissions. The environmental impacts of mining coal are massive and well documented, and the recent tragedy in West Virginia has brought attention back to the health and safety risks of mining. Mountain top removal presents different risks and costs to communities where it is employed. Coal ash wastes present additional costs and risks to communities around the country. Nuclear power produces high-level radioactive waste, and the nation still has not established a long term repository for that waste. For the indefinite future, the waste will be stored throughout the country at the power plants themselves. The risk of accidents would also increase with additional nuclear plants, and while the nuclear industry assures us that these risks are vanishingly small, history argues that they are not.

This study challenges the assumptions that coal and nuclear power must be key parts of our response to climate change. We investigate a scenario in which the country transitions away from coal and nuclear power and toward more efficient electricity use and renewable energy sources. Specifically, coal-fired generation is eliminated by 2050 and nuclear generation is reduced by over one quarter. We perform a simple and transparent analysis of the costs of this strategy relative to a "business as usual" scenario, which includes expanded use of coal and nuclear energy. We also estimate the reductions in air emissions and water use that would result from this strategy. We do not quantify other benefits of the strategy, such as reduced solid waste from coal and nuclear plants or reduced environmental impacts from mining.

The goal of the study is to provide a highly transparent and objective analysis of the cost of moving away from coal and nuclear energy and toward efficiency and renewables. Toward this end, we have used cost data from actual recent projects wherever possible rather than from researchers' estimates or industry targets. We include in our analysis the costs of integrating large amounts of variable generation into the nation's power system and the cost of new transmission needed to deliver renewable energy to load centers. The study is a high-level view of a nationwide strategy, and it is designed to help identify areas where more detailed analysis is needed.

This work is motivated by a simple realization. The need to reduce CO_2 emissions will force a major retooling of the electric industry. If we retool around coal and nuclear energy, we will exacerbate a number of environmental, health, and safety problems. If we retool with efficiency and renewable energy, we will largely eliminate those problems. Moreover, the traditional arguments against renewable energy are no longer valid. Energy efficiency and several renewable technologies now cost less than new coal and nuclear plants in terms of direct costs—ignoring the externalized costs of coal and nuclear energy. Additionally, efficiency and renewables are already in commercial operation, so the technology development and commercialization challenge of retooling with these technologies appears smaller than the challenge of developing low-carbon coal technologies and a new fleet of nuclear plants.

Moreover, there is no rush to build additional capacity. Surplus generating capacity in every region of the country provides us the time to carefully and systematically increase investment in renewables and energy efficiency while we reduce investment in coal-fired and nuclear power.

Section 2 of this report outlines the methodology and key assumptions. Section 3 presents the results for the U.S. as a whole, and Section 4 presents results on the regional level. Section 5 summarizes our conclusions. Appendix A describes our methodology in greater detail, and Appendix B describes our assumptions about the cost and performance of technologies in the Transition Scenario. Appendix C shows presents data in tabular form from selected charts in the report.

2. Methodology and Assumptions

This section briefly describes the methodology of this study and our key assumptions. The methodology is discussed in more detail in Appendix A, and the assumptions, in Appendix B.

A. Methodology

Our method is essentially a spreadsheet-based analysis of regional energy balances. We began with data from the 2010 Annual Energy Outlook (AEO), released by the Energy Information Administration (EIA) in December 2009. Each year EIA uses the National Energy Modeling System (NEMS) to model a “Reference Case” energy scenario. EIA then analyzes various policy proposals by modeling the policy and comparing the results to the Reference Case. The AEO 2010 simulates U.S. electricity production and use through 2035.

The steps of our methodology are laid out briefly here and discussed in more detail in Appendix A.

- First, we developed our Reference Case by extrapolating the AEO 2010 data on demand, generation by fuel, capacity additions and emissions from 2035 through 2050. We did this based on average rates of change during the AEO study period.
- Second, we developed cost and performance assumptions for each resource type. We did this based on an extensive review of the current literature and on electric industry data that Synapse maintains. We used the AOE 2010 costs for very few technologies, primarily because these data do not appear to account for recent escalations in construction and materials costs.
- Third, electricity loads were reduced from the AOE 2010 loads to simulate a concerted, national effort to become more energy efficient.
- Fourth, we developed a scenario in which all coal and as much nuclear capacity as possible is phased out by 2050 – the Transition Scenario. We did this in an iterative way. Coal-retirement and renewable energy development scenarios were sketched out for each region based renewable technology cost data and each region’s resources. Coal-fired capacity was retired at a rate that would not result in unrealistic development scenarios or costs. After rough scenarios were sketched out, the costs of new technologies over the study period were refined, based on the amount of capacity added nationwide. Then capacity additions were refined again, and so on.
- Fifth, we assessed the amount of generating capacity relative to load throughout the Transition Scenario. To do this, we used data from utility efficiency programs to estimate the impact of efficiency on peak loads and compared peak loads throughout the study period to capacity, with wind and solar capacity derated.
- Sixth, we estimated the incremental cost of transmission upgrades in the Transition Scenario. In this scenario, new investment is needed in transmission capacity to support increased interregional energy flows. We compared interregional transfers

in the Reference and Transition Cases and estimated the cost of the new transmission capacity necessary to accommodate the incremental flows.

- Seventh, we estimated the savings the Transition Scenario would provide from avoided emission control investments at coal-fired plants. Three federal regulations have been promulgated that will require new emission controls at existing coal-fired power plants: the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR), and the Clean Air Mercury Rule (CAMR). We assume that plants committing to retire in the 2010 to 2020 period would not be required to install controls pursuant to these rules. We estimate the avoided cost using assumptions about the cost of control and the number of control systems avoided. See Appendix A for more on this calculation.
- Finally, we calculated the net cost of the Transition Scenario relative to the Reference Case. To do this, we calculated the cost of each resource that was utilized differently in the two cases. Resources that generated the same amount of energy were not included in the cost analysis, as the net cost of these resources would be zero. We then subtracted the cost of the Reference Case from that of the Transition Scenario to determine the net costs. Costs are analyzed over the study period in constant 2009 dollars. Further, we focus on the total direct costs of generation to society. This means that, first, we do not include the effects of subsidies and tax incentives in the costs of generating technologies. Second, it means that we have not included "externalized" costs, such as the health effects of pollution from power generation or the environmental impacts of coal mining. Perhaps the most important cost we have ignored is that of carbon emissions. The Transition Scenario reduces CO_2 emissions over the study period by a cumulative 55 billion tons. If a dollar value were placed on these reductions, it would change our net cost estimate dramatically.

B. Cost and Performance Assumptions

In developing cost and performance assumptions for the Reference Case and the Transition Scenario, we have been guided by a number of recent studies. This section briefly presents our assumptions about each resource and conversion technology and the information on which we base those assumptions. See Appendix B for a more detailed discussion.

One factor we have been careful to capture in our assumptions is the increased cost of construction and many construction inputs over the last five years. A number of articles and cost indices document these cost increases (see, for example, Wald 2007). The Union of Concerned Scientists (UCS) assessed the increases thoroughly for its Climate 2030 study, reviewing actual project data and several construction cost indices. They found real cost increases of "50 to 70 percent since 2000, with most of them occurring after 2004" (see UCS 2009, Appendix D). These increases have affected nearly all types of new power plants.

There is some evidence that construction and materials costs are beginning to fall, perhaps as a result of the global recession. Thus, our 2010 cost assumptions reflect higher current construction and materials costs, and we assume a trend back to historical levels by the midpoint of this decade. For the capital-intensive technologies with long construction periods (nuclear, coal, geothermal and biomass), we have raised installed costs in 2010 by roughly 20% as it appears that most of our sources have captured some, but not all of the construction cost increases. For less capital intensive technologies, like combined-cycle combustion turbines, 2010 costs are 10% above historical levels. In both cases, capital costs return to historical levels during the next decade.

Beyond falling near-term construction costs, our costs trajectories are largely a function of capacity additions. For less mature technologies, where much more capacity is added in the Transition Scenario than the Reference Case, costs fall faster in the Transition Scenario than the Reference Case. This is consistent with the way that cost trajectories are determined within NEMS, however we do not use the function NEMS uses to determine future costs. Our future costs are based on our review of the literature for each technology. This allows us to have costs fall based on a wide range of opinions and forecasts for each technology and its supply chain, rather than trying to summarize these dynamics for all technologies in a single function. In this Section we show how costs fall with capacity additions for each new technology.

Energy Efficiency

While energy efficiency programs have been common in the U.S. for several decades, the potential for energy savings remains vast. In fact, as more efficient equipment has been adopted, advancing technology has continued to provide more and more efficient solutions. For example, compact fluorescent lights reduce energy use relative to incandescent bulbs significantly. However, next generation technologies, like LED lighting, promise to provide considerable savings relative to compact fluorescents.

In the Transition Scenario we envision a concerted, national effort that includes aggressive R&D support and market transformation efforts designed to remove barriers to efficiency and pull new technologies into markets. Over recent decades a combination of incentives (including utility programs and tax policies) and standards (including the Department of Energy's standards for buildings and various types of equipment) have resulted in significant improvements. We anticipate a continuation of these efforts with increasingly higher levels of efficiency over the coming decades. As the high end of the range of available equipment is incrementally improved over time (through innovation driven in part by incentives) the levels of minimum standards can be increased, cutting the poorest performing equipment from the market entirely.

In the Transition Scenario, we envision an expansion in the scope of the nation's efficiency efforts as well as increasing standardization and economies of scale in the provision of those services. We assume that these efforts begin in 2011, reducing electricity use from Reference Case levels by 0.2% in that year. Annual savings grow to 2.0% by 2021 and stay there for the remainder of the study period. As discussed in Appendix B, several utility programs are *currently* reducing energy use by 2.0% per year, and the effects of codes and standards provides additional savings on top of utility programs. We assume an average total cost (utility and participant) of 4.5 cents/kWh for efficiency, based on a number of studies (discussed in Appendix B).

Wind Energy

See Appendix B for a discussion of wind energy potential and recent cost data. The most detailed analysis of U.S. wind cost and potential was performed for the DOE's 2008 study 20*% Wind Energy by 2030* and its predecessor, AWEA's 2007 report *20 Percent Wind Energy Penetration in the United States* (DOE EERE 2008 and AWEA 2007). Both reports include detailed supply curves for wind energy in each of nine U.S. regions. These supply curves are based on analyses of site types in different regions of the country. Because of this rich regional detail, we use these supply curves as the basis of our wind buildout in the Transition Scenario and for costs in both scenarios. However we adjust the installed cost of wind in the 2010 supply curves to account for the increased construction costs discussed above. AWEA 2007 uses total installed costs of 1,750 $/kW for onshore wind, and we adjust this to 2,200 $/kW. AWEA uses 2,490 $/MWh for offshore projects and we adjust this to 3,500 $/MWh.

See Figure 23 in Appendix B for the AWEA 2007 supply curve. The AWEA 2007 report divides this supply curve into nine regional supply curves, and it breaks costs into: capital costs, fixed and variable O&M, regional construction factors and regional transmission adders.[1] This detail allowed us essentially to update the regional supply curves for 2010 by increasing the installed costs and leaving the other components unchanged. Installed costs in both scenarios fall between 2010 and 2020 based on projected decreases in construction costs and global learning and market maturation. After 2020, installed costs fall faster in the Transition Scenario based on the larger cumulative U.S. capacity additions in that scenario. We assume that these additions would better develop the U.S. turbine industry, leading to cost reductions relative to the Reference Case. The costs we use for wind energy in the two cases as well as cumulative capacity additions are shown in Table 1 below.

Annual energy production in each region is calculated in each region based on installed capacity and capacity factors from AWEA 2007. The supply curves from AWEA 2007 show how lower wind classes must be tapped as more capacity is added in each region (see Figure 23). Using these data, we decrease wind capacity factors as capacity is added in each region, simulating the development of the best wind sites first. Thus, the levelized cost of new wind plants over time is a function of both the falling capital costs shown in Table 1 and falling capacity factors, which are a function of capacity additions in each region. After 20 years, wind sites are assumed to be repowered with new turbines at a cost of 75% of the current cost of a greenfield project.

[1] The regional construction factors capture the differing costs of construction in different regions of the country. The factors are: 26% for the Northeast; 16% for the MidAtlantic; 12% for the Great Lakes and 6% for the Southeast. Construction factors are not added in other regions of the country.

Table 1. Installed Wind Costs through the Study Period

	2010	2020	2030	2040	2050
Reference Case					
Cumulative Onshore Cap. (MW)	39,000	66,000	68,000	75,000	86,000
Cumulative Offshore Cap. (MW)	0	200	200	200	200
Northeast Onshore ($/kW)	$2,800	$2,100	$2,000	$1,900	$1,800
Northeast Offshore ($/kW)	$4,400	$3,300	N/A	N/A	N/A
Southeast Onshore ($/kW)	$2,300	$1,700	$1,700	$1,600	$1,500
Southeast Offshore ($/kW)	$3,700	$2,800	N/A	N/A	N/A
S. Central Onshore ($/kW)	$2,200	$1,700	$1,600	$1,500	$1,400
E. Midwest Onshore ($/kW)	$2,500	$1,800	$1,700	$1,700	$1,600
W. Midwest Onshore ($/kW)	$2,200	$1,700	$1,600	$1,500	$1,400
Northwest Onshore ($/kW)	$2,200	$1,700	$1,600	$1,500	$1,400
Southwest Onshore ($/kW)	$2,200	$1,700	$1,600	$1,500	$1,400
California Onshore ($/kW)	$2,400	$1,800	$1,700	$1,600	$1,500
Transition Scenario					
Cumulative Onshore Cap. (MW)	39,000	99,000	144,000	178,000	222,000
Cumulative Offshore Cap. (MW)	0	4,600	9,400	16,000	27,000
Northeast Onshore ($/kW)	$2,800	$2,100	$1,900	$1,800	$1,700
Northeast Offshore ($/kW)	$4,400	$3,100	$2,500	$2,300	$2,300
Southeast Onshore ($/kW)	$2,300	$1,700	$1,600	$1,500	$1,500
Southeast Offshore ($/kW)	$3,700	$2,600	$2,100	$2,000	$1,900
S. Central Onshore ($/kW)	$2,200	$1,700	$1,500	$1,400	$1,400
E. Midwest Onshore ($/kW)	$2,500	$1,800	$1,700	$1,600	$1,500
W. Midwest Onshore ($/kW)	$2,200	$1,700	$1,500	$1,400	$1,400
Northwest Onshore ($/kW)	$2,200	$1,700	$1,500	$1,400	$1,400
Southwest Onshore ($/kW)	$2,200	$1,700	$1,500	$1,400	$1,400
California Onshore ($/kW)	$2,400	$1,800	$1,600	$1,500	$1,500

In addition, to account for the cost of integrating wind generation into regional power systems, we add 2 $/MWh to the cost of all wind energy when it reaches 10% of total energy in a region. We add 4 $/MWh when it reaches 15% and 5 $/MWh when it reaches 20%. These cost adders persist throughout the study period. As discussed in Section 3, depressing loads with energy efficiency, removing coal and nuclear generation from regional supply mixes, increasing the size of balancing areas and expanding demand response programs will all make it easier for regions to accommodate variable generation. Thus, we believe it is conservative to assume that these costs persist throughout the study period.

Photovoltaics

Current costs of PV systems are high relative to many other technologies. See Appendix B for more on the PV potential across the country and current and historical cost data. Table 2 shows the installed costs we use for PV in the Reference Case and Transition Scenario over the study period. By 2030, more than twice as much capacity has been added in the Transition Scenario than in the Reference Case, and installed costs are about 13% lower due to more assumed learning and U.S. market maturation. In addition to these installed costs, we assume fixed O&M of 41 $/kW-yr for distributed projects and 35 $/kW-yr for central projects. These costs do not fall over the study period. Capacity factors for new PV rise from 23% to 27% over the study period for distributed projects and from 26% to 28%

for central projects. After 20 years we assume that PV panels are replaced at 75% of the cost of a new project.

Table 2. Installed Cost of PV Projects through the Study Period

	2010	2020	2030	2040	2050
Reference Case					
Cumulative PV Cap. (MW)	2,100	10,000	12,000	19,000	39,000
PV Distributed Cost ($/kW)	$7,100	$5,000	$4,500	$4,200	$3,900
PV Central Cost ($/kW)	$6,000	$4,200	$3,800	$3,600	$3,300
Transition Scenario					
Cumulative PV Cap. (MW)	2,100	14,000	28,000	39,000	55,000
PV Distributed Cost ($/kW)	$7,100	$4,600	$3,900	$3,700	$3,600
PV Central Cost ($/kW)	$6,000	$3,900	$3,300	$3,200	$3,100

Concentrating Solar Power

Concentrating solar power (CSP), also known as solar thermal power, uses the heat of the sun to generate electricity. CSP plants are utility-scale generators that use mirrors and lenses to concentrate the sun's energy to activate turbines, engines, and photovoltaic cells to produce electricity. Maximum power is generated by CSP plants in the afternoon hours, and this correlates well with peak electricity loads in hot climates. Unlike PV systems, which can use diffuse, CSP systems require direct sunlight, known as "direct-normal solar radiation." See Appendix B for more information on CSP potential and costs.

Table 3 shows the costs we use for CSP projects in the Reference Case and the Transition Scenarios. By 2050, almost ten times as much CSP capacity has been added in the Transition Scenario, and installed costs are significantly lower. We used different costs In the Transition Scenario for CSP projects with and without energy storage capacity. In the Reference Case, we applied the average of the two costs to all CSP projects, as we do not know what assumptions EIA makes on this point. However, we ended up modeling about half the capacity with storage and half without in the Transition Scenario, so in this sense, the scenarios are quite similar. The assumption about storage affects only the cost, not the capacity factor: capacity factors for all new CSP projects rise from 38% in 2010 to 46% in 2050. In both scenarios we assume that all new CSP plants are required to use dry (air) cooling systems.

Table 3. Capacity Additions and Installed Cost of CSP Projects through the Study Period

	2010	2020	2030	2040	2050
Reference Case					
Cumulative CSP Cap. (MW)	610	890	930	1,100	1,300
CSP Cost ($/kW)	$5,300	$4,800	$4,700	$4,500	$4,400
Transition Scenario					
Cumulative CSP Cap. (MW)	610	3,700	7,500	11,000	14,000
CSP Cost ($/kW)	$4,700	$3,300	$2,800	$2,700	$2,600
CSP w/ storage Cost ($/kW)	$6,000	$4,800	$3,800	$3,400	$3,300

In addition to these installed costs, we assume fixed O&M of 41 $/kW-yr for distributed projects and 35 $/kW-yr for central projects, based on these same sources. These costs do not fall over the study period. Capacity factors for new CSP plants rise from 38% to 46% over the study period. After 30 years CSP projects are "repowered" at a 30% of the cost of a greenfield project. This is to simulate the fall in the levelized cost of energy as initial capital costs are recovered and capital additions are incurred to replace aging components.

Biomass

A wide range of biomass fuels are used for energy production. First, there are various waste gases, methane rich gases emitted by landfills, wastewater treatment, and animal wastes. Second, there are solid waste streams: logging and sawmill wastes, crop residues, food production wastes and urban wood wastes. Third are dedicated energy crops – plants grown specifically to be used as fuel. Corn is currently the largest dedicated energy crop in the U.S., however it is used to make liquid fuel, not to generate electricity. While there has been considerable research on energy crops for electricity production, they are not yet grown on a widespread basis. Research has focused primarily on switchgrass and willow/poplar hybrids – and more recently on duckweed and water hyacinths (see Makhijani 2008).

The use of waste gases for energy production is not controversial, nor is the use of mill and urban wood wastes. These are considered "opportunity" fuels, free or lower cost byproducts of other activities. The use of the other biofuels listed above is extremely controversial. Use of logging wastes removes nutrients that would otherwise return to the soil and can exacerbate erosion problems on recently logged land. The use of crop residues removes nutrients from croplands resulting in more fertilizer use. Devoting land to dedicated energy crops can, in some cases, negatively impact animal habitats and/or the scenic and recreational value of the land. And all of these fuels—timber and crop wastes and dedicated energy crops—are typically harvested and transported by machines burning fossil fuels.

All of these concerns about biomass as an energy fuel are legitimate, and taken together, they lead to two important conclusions:

- First, in growing and harvesting biomass for energy use, we must carefully consider the full range of impacts.
- And second, we must use the biomass fuels we do harvest as efficiently as possible.

In light of these points, we are conservative in our use of this resource in the Transition Scenario, and we utilize a significant portion of the resource in CHP plants. For comparison, over 100,000 MW of biomass capacity is added by 2050 in the Reference Case, while we add a total of 23,000 MW in the Transition Scenario. See Appendix B for a discussion of the biomass potential data we have used in developing the Transition Scenario.

For new direct fire biomass systems, we use the installed cost from AEO 2010, but we increase this cost 20% to account for the higher construction and materials costs as discussed above. The result is 4,400 $/kW. We assume that installed costs come down by 20% by 2020 and come down 1% per decade after that, since this is a mature technology. We include fixed O&M of 67 $/kW-yr and variable O&M of 6.90 $/MWh and use a 2010 heat rate of 9,450 Btu/kWh – all from AEO 2010.

As noted, over 100,000 MW of biomass capacity is added in the Reference Case. First, we do not know how much of this is direct fire and how much is CHP. Thus, we cost out all the biomass generation in the Reference Case as direct-fire combustion. Second, because so much is added, we increase the average biomass fuel cost in the Reference Case from 2.00 to 3.00 $/mmBtu in the later decades. For direct-fire biomass in the Transition Scenario (23,000 MW) the fuel cost stays at 2.00 $/mmBtu throughout the study period.

In the AEO 2010, EIA does not include any net CO_2 emissions from biomass plants. While we do not believe that all near-term biomass projects will be carbon neutral, we use the same assumption in the Transition Scenario in order to be consistent with the Reference Case. Regarding NO_x emissions from biomass, EIA staff could not tell us what NO_x emission rate is applied to biomass in the Reference Case. This is troubling, especially since so much energy is produced from biomass in the Reference Case. We apply a NO_x rate of 0.2 lb/mmBtu to biomass combustion based on MA DOER, 2008.

For the cost and performance of biomass CHP, we rely primarily on EPA 2007. This study provides a detailed analysis of biomass CHP technologies and their costs. We use the characteristics of a stoker boiler with a 600 ton per day capacity to represent biomass in the Transition Scenario. (Fluidized bed boilers are quite common too, but the costs and performance of these is very similar to stokers.) EPA 2007 includes a cost of $4,900 $/kW for the stoker boiler. We increase this by 20% in 2010 for higher construction costs and bring it back down by 2020. Costs fall by 1% per decade after 2020. We use total non-fuel O&M costs of 36 $/MWh and fuel costs of 3.00 $/mmBtu to account for increased average distance to CHP sites relative to direct fire plant sites.

For anaerobic digester gas (ADG) and landfill gas (LFG) projects, we assume generation using an internal combustion engine, as we project this to be the lowest cost technology throughout the study period. We assume that third party developers pay landfill owners an average of 1.00 $/mmBtu for gas. For ADG projects we assume no gas cost. All costs and operating characteristics are based on ACEEE 2009b. Installed costs are increased by a factor of 1.25 to account for these specialized applications. LFG projects are modeled on a 3-MW engine.[2] Installed costs are 1,400 $/kW, O&M is 1.8 cents per KWh, and the 2010 heat rate is 9490 Btu/kWh. Wastewater treatment ADG projects are modeled on a 100 kW engine. Installed costs are 2,800 $/kW; O&M is 2.5 cents per kWh; and the 2010 heat rate is 12,000 Btu/kWh. For farm-based ADG systems we use capital costs of the digester and genset together of 5,150 $/kW, and operating characteristics of an 800 kW generator. Total O&M is 3.0 cents per kWh; and the 2010 heat rate is 9,760 Btu/kWh. All heat rates fall over time based on ACEEE 2009b.

Geothermal

There are two types of geothermal systems from which heat can be extracted to generate electricity. The system used depends on the site-specific geological structure of the heat resource. The first type is hydrothermal, in which the geology and heat resource allow energy to be extracted with little additional work to move water through the system and up

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[2] Data from EPA's Landfill Methane Outreach Program show an average project size of roughly 3 MW for existing LFG projects.

to the surface. The second type of system can extract energy from heat sources deeper below the earth’s surface. These areas either lack water or are characterized by rocks with low permeability. Enhanced geothermal systems (EGS) work to create an engineered hydrothermal system through hydraulic fracturing.

Finally, heat energy often becomes available when oil and gas wells are drilled, and recent research suggests that, in the case of existing wells, “co-produced” heat could be captured at much lower cost than with hydrothermal or EGS systems. The authors of NREL’s 2007 geothermal resource inventory write: “coproduced resources collectively represent the lowest-cost resources… reflecting the assumption that this potential can be developed using mostly existing well infrastructure” (NREL 2007, p. 16). However, serious efforts to capture this resource have only just begun, and more work is needed to determine exactly what infrastructure would need to be added to existing oil and gas fields.

NREL 2007 provides a detailed analysis of the U.S. geothermal resource and the cost of capturing it in different places. Our costs are based on this study, with increased installed costs as described in Appendix B. Figure 1 below shows the biomass supply curves we use at different points in the study period. While these data are shown nationally here, we have used the underlying data to create regional supply curves. The major shift in the supply curve between 2010 and 2030 is the result of adding in co-produced resources over that period. Because these resources have not been widely tapped yet, we assume that they are not available in the 2010 to 2020 period. We assume that half the total co-produced resource becomes available in 2020 and the other half in 2030.

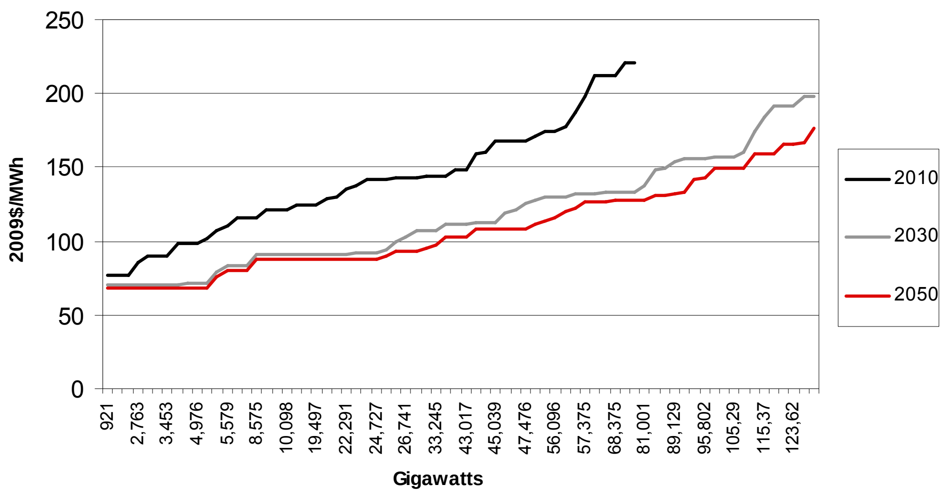

Figure 1. Geothermal Energy Supply Curves

Coal-Fired Plants

The cost of new coal-fired plants has increased considerably over the past decade. See Appendix D of UCS 2009 for a discussion of the trend in costs up to 2008. Costs have continued to increase since then. Based on UCS and other recent data, we use a 2010 total installed cost for new coal of 4,000 $/kW, including interest during construction. Fixed O&M is 28 $/kW-yr, and variable O&M is 4.70 $/MWh, both from AEO 2010. Our assumed heat rate, 9,200 Btu/kWh, is also from AEO 2010. We assume an 85% capacity factor.

Total installed costs fall by 20% between 2010 and 2020, due to falling construction and materials costs. Costs fall by only 1% per decade thereafter, because this is a mature technology.

Once coal plants reach age 40, we assume they are essentially rebuilt *in situ* over the next several decades. The original capital costs are now fully recovered, and we assume that capital additions of $100 per $/kW-yr are needed to rebuild the plant.[3] This assumption of rebuilding *in situ* is more consistent with the way these plants are actually being treated than the assumption that plants are retired at a specific age and replaced with completely new plants.

The coal prices we use, shown in Table 4, are based on the AEO 2010 Reference Case. We have extrapolated them to 2050 based on average trends from 2012 through 2035.

Table 4. Coal Prices, Based on AEO 2010 ($/mmBtu)

2010	2020	2030	2040	2050
$1.55	$1.54	$1.41	$1.41	$1.35

Nuclear Plants

Until several years ago, there had been no serious proposals for new nuclear plants in the U.S., and cost estimates were little more than guesses. When companies began to get actual quotes from vendors, costs were much higher than expected, and cost estimates for the projects under development have continued to climb as the projects have progressed. For example,

- Florida Power and Light's latest cost estimate for two new units is $12 to $18 billion (Reuters 2010, Grunwald 2010). FPL recently delayed the project when the Florida Public Service Commission denied proposed rate increases.
- Progress Energy's cost estimate for two new units north of Tampa Bay tripled over the course of a year reaching $17 billion (Grunwald 2010). This project has also been delayed.
- In November 2009, CSP Energy disclosed that costs of the planned expansion of the South Texas nuclear station had risen from $13 to $17 billion (EUW, 2009).
- The first "new generation" nuclear unit actually to begin construction, Finland's Olkiluoto 3, had seen cost escalations of $2 billion by 2009, and the developer and the utility buying the plant were in arbitration in that year over responsibility for the cost overruns (Schlissel, et. al., 2009).

[3] We do not make this change to costs on a unit-by-unit basis. We change the costs of large blocks of capacity based on unit-specific on-line dates in EPA and EIA data.

Because no investment banks have been willing to finance new nuclear plants, the Obama Administration has stepped in with loan guarantees. The first federal guarantee of $8.3 billion went to two proposed units at the Vogtle plant in Georgia. In Florida and Georgia, laws have been passed allowing utilities to begin collecting the costs of new nuclear units before the units are in service, to protect utilities' cash flow and credit ratings. For example, Progress Energy is collecting money from ratepayers for the project cited above, although the company has delayed the project. The delays and escalating costs have caused a consumer backlash and now some lawmakers want the laws overturned.

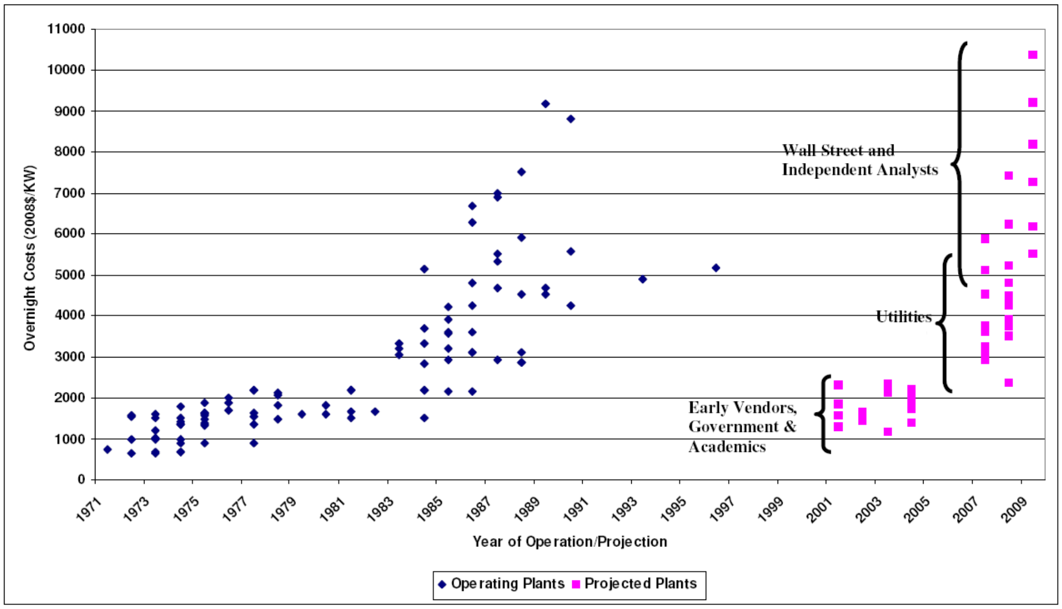

Figure 2. Historical Nuclear Costs and Estimates of Future Costs (Cooper, 2009)

Law professor Mark Cooper has compiled cost data from the existing U.S. reactors and estimates for new units. Figure 2 above shows these data, with the estimates for new plants divided into the different entities making the estimate (Cooper 2009). The trend of rising estimates is clear. Note that the estimates in this figure are "overnight" costs, which do not include interest during construction. Interest can easily add 20% to the cost of a nuclear plant, and more when long construction delays occur.

We use a total installed cost of 8,000 $/kW for the new nuclear plants added in the Reference Case – $8 billion for a 1,000 MW plant. This figure includes interest during construction. For fixed O&M we use 93 $/kW-yr, and for variable O&M we use 0.5 $/MWh, both from AEO 2010. Installed costs fall by 8% by 2020 to account for falling construction and materials costs. Costs fall 2% per decade after 2020.

Between 2010 and 2020, installed costs of nuclear plants do not fall as much as those of coal plants because the escalating nuclear cost estimates are quite different from the rising actual costs of coal and other plant types. That is, increased construction costs are likely to be responsible for some of the rising nuclear estimates, but poor initial estimates and a withered supply chain are also factors. For example, only two companies worldwide are qualified to forge nuclear pressure vessels, steam generators and pressurizers. In addition, utilities proposing new nuclear units have discovered a scarcity in the U.S. of "N-stamp" technicians – workers certified by the NRC to build certain components of nuclear plants (Harding, 2008).

Again, the 8,000 $/kW installed costs are only applied to the new nuclear plants in the Reference Case. To calculate the cost of energy from existing nuclear plants, we use annual capital additions of 200 $/kW-yr to cover the cost of rebuilding plants over a period of several decades, and the same O&M costs listed above.

Combined-Cycle Combustion Turbines

Combined-cycle combustion turbines (CCCT) are very attractive in that they are not as capital intensive as coal and nuclear plants and construction times are significantly shorter, reducing the risk of cost overruns. There was a large boom in CCCT construction in the U.S. during the 1990's and 2000's. This boom, coupled with the current recession, has left the country with surplus capacity and left many CCCTs operating at low utilization rates.

We have not increased current CCCT costs as much as those of coal and nuclear plants, because CCCTs are less capital intensive. We use total installed costs of 995 $/kW, based largely on AEO 2010 with some escalation for higher near-term construction costs. For fixed O&M we use 13 $/kW-yr, and for variable O&M we use 2.10 $/MWh, both from AEO 2010. We use a heat rate of 7,196, also from AEO 2010. For older CCCT's (after initial capital costs have been paid off), we assume capital additions of 56 $/kW-yr.

The gas prices we use, shown in Table 5 are based on the AEO 2010 Reference Case. We have extrapolated them to 2050 based on average trends from 2012 through 2035.

Table 5. Natural Gas Costs, Based on AEO 2010 ($/mmBtu)

2010	2020	2030	2040	2050
$4.89	$6.48	$7.80	$9.86	$13.12

3. Results

This Section compares the Reference and Transition Scenarios at the national level in terms of electricity generation, air and water impacts, and costs. We examine the regional implications in Section 4.

In the Transition Scenario, we begin in 2010 with the same regional loads and generating mixes as in the Reference Case. However, a coordinated and sustained national efficiency effort slows load growth in this scenario, and by 2021 the nation is saving energy each year equal to 2% of electricity use. As discussed in Appendix B, this level of savings is currently being achieved by several U.S. utilities, and we assume that a strong, nationwide push on efficiency could bring annual savings throughout the country to this level. As shown in Figure 3, savings at this level would reduce electricity generation from 4,000 TWh in 2010 (as predicted in the AEO 2010 Reference Case) to 3,600 TWh in 2050.

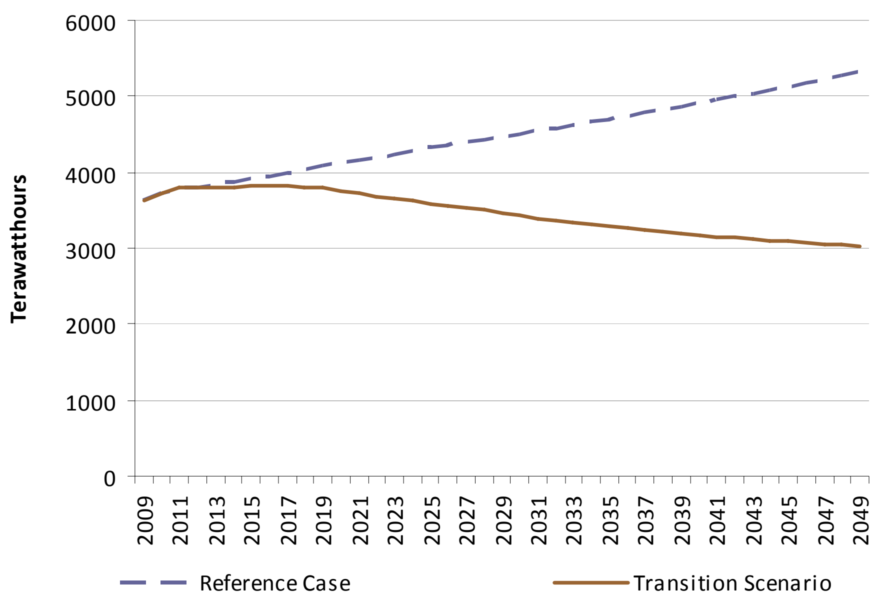

Figure 3. Electricity Use in the Reference and Transition Cases

The electricity fuel mix in each decade of the Transition Scenario is shown in Figure 4. (See Appendix C for tabular versions of all bar charts.) Coal-fired generation is reduced by nearly 1,800 TWh (100%) between 2010 and 2050.[4] Nuclear generation is reduced by 220 TWh relative to 2010, and it comprises only 17% of total generation in 2050. Generation at gas-fired central station plants (i.e., not CHP plants) falls by 37 TWh. The nation's electricity fuel mix becomes much more diverse by 2050.

4 We have rounded numbers to two significant figures in presenting results.

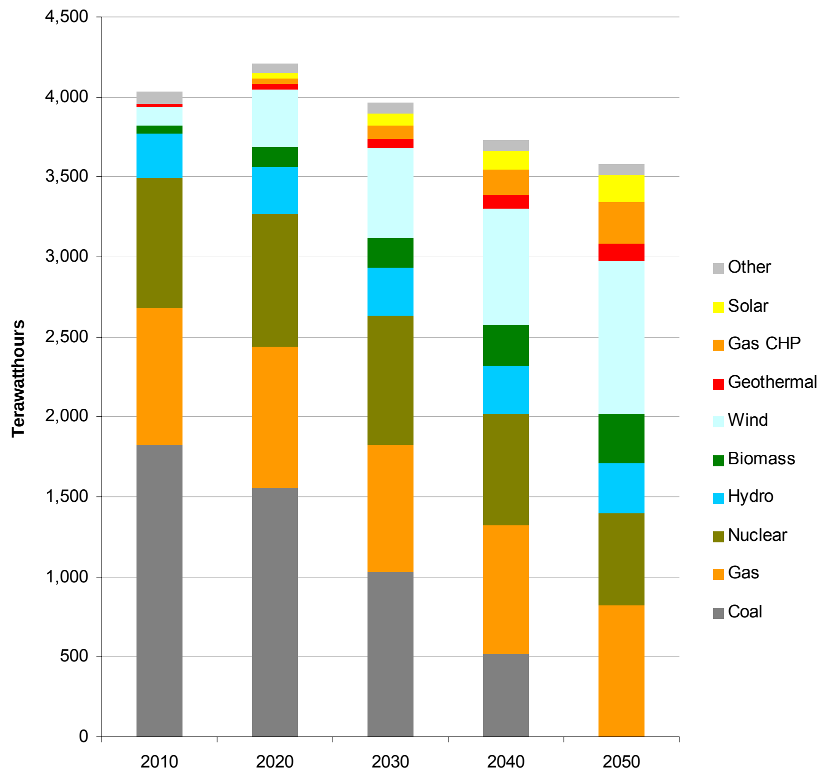

Figure 4. The Resource Mix in the Transition Scenario

Key aspects of the Transition Scenario are as follows:

- Energy efficiency reduces demand an average of 1.3% per year over the study period. Generation falls to 3,600 TWh in 2050. Reference Case generation in this year is 5,900 TWh.
- All coal-fired plants are retired – 320,000 MW. In the Reference Case, 22,000 MW of new coal capacity are added and coal-fired generation increases by 670 TWh (37%) over the study period.
- Nearly 30,000 MW of nuclear capacity is retired, and nuclear generation falls by 240 TWh (30%).
- Gas-fired generation at central-station plants falls, and production at gas-fired CHP plants rises. In 2050, overall gas-fired generation is up 26% relative to 2010, but it is 230 TWh (18%) below Reference Case levels.
- The nation taps its massive wind energy resource. Roughly 220,000 MW of onshore wind capacity generates 810 TWh in 2050, 26% of the national mix. On the east coast, 27,000 MW of off-shore capacity produces 3.4% of the nation's electricity.
- The country's biomass resource is used conservatively: 34,000 MW of biomass capacity are added, roughly a quarter of the capacity added in the Reference Case. It produces 9% of the nation's electricity by 2050. Direct-fire plants

produce 4%; biomass CHP plants produce 2%; and combustion of waste gases produces 3%.

- 53,000 MW of solar PV capacity is added, and PV produces 3.3% of the nation's electricity in 2050. Nearly 14,000 MW of solar thermal capacity is added, producing 1.5% of electricity.
- New biomass- and gas-fired CHP capacity in the Transition Scenario generate 314 TWh of electricity in 2050, 9% of national generation. These plants avoid the combustion of 3.6 quadrillion Btu for process and space heating. If the avoided fuel were gas, the savings in 2050 would total nearly $50 billion.

Figure 5 below compares the energy mix in the Reference and Transition Cases in the years 2010, 2030, and 2050. Note that in 2050 energy efficiency reduces total generation from 2010 levels by a small amount, but the reduction relative to the Reference Case in 2050 is dramatic. Forty years of compounding underscores the importance of a more efficient electricity future.

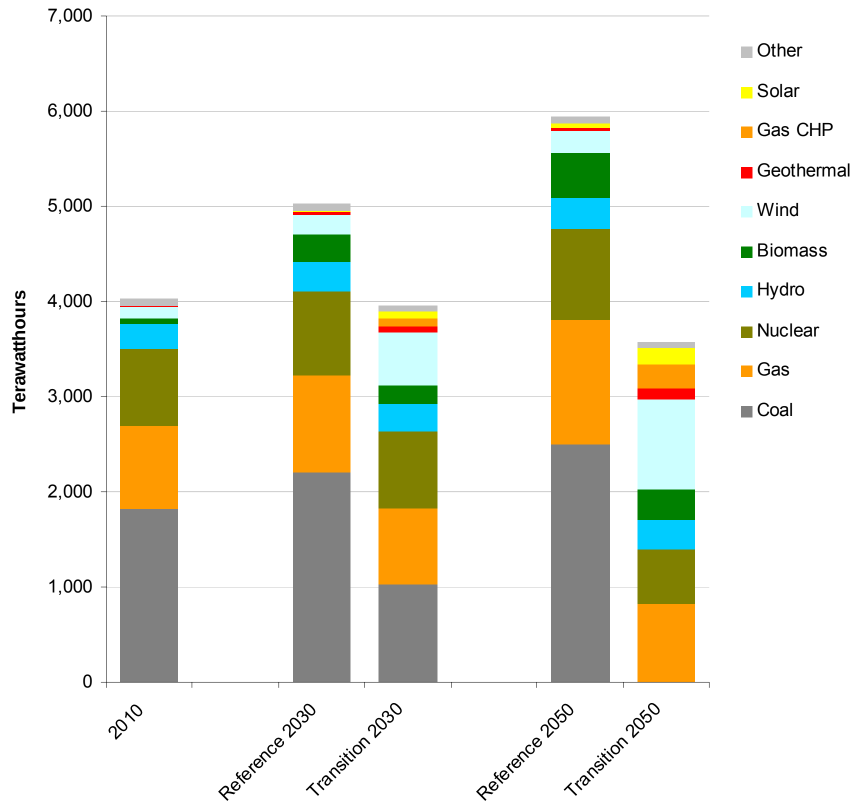

Figure 5. The Resource Mix the Reference and Transition Cases

A. Supply-Side Efficiency

A critical aspect of the Transition Scenario is more efficient use of fuels like biomass and natural gas. By 2050 we add over 42,000 MWe in CHP capacity, and it produces 315 TWh of energy. We add roughly 7,900 MWe of biomass-fueled CHP by 2050. These units would burn 3.1 quadrillion Btu of biomass in that year and produce 59 TWh of electricity and 2.0 quadrillion Btu of useful heat, for an overall efficiency just over 70%. A key priority in the Transition Scenario would be to identify potential CHP hosts—schools, hospitals, shopping malls, office parks, and other commercial and industrial facilities—near biomass feedstocks.

We also include 34,000 MW of gas-fired CHP capacity by 2050. This capacity would burn 2.3 quadrillion Btu of gas in 2050 and generate 260 TWh of electricity and 0.9 quadrillion Btu of useful heat.

Together, the biomass- and gas-fired CHP systems would avoid the combustion of 3.6 quadrillion Btu of fuel for space and process heat in 2050. If the avoided fuel were gas, the annual savings in 2050 would total nearly $50 billion. We have not included these estimated savings in calculating net cost of the Transition Scenario. This is because the CHP plants added in the Reference Case would also displace fuel use outside the electric sector, yet we do not know exactly how much CHP is added in the Reference Case or what the operating characteristics of those plants are (e.g., power to heat ratio).

B. System Planning and Operation

The U.S. currently has significant surplus generating capacity, largely due to the gas-fired capacity additions of the 1990s and 2000s and the current recession. Reducing energy use with aggressive efficiency efforts now would extend and increase this surplus. Thus, we would expect reserve margins to be maintained easily in the Transition Scenario, and the results of a rough reserve margin analysis support this expectation.

We first estimated the effect on peak load of a MWh saved by a typical suite of efficiency programs. Most states require annual efficiency program reviews, and most of these reviews address the issue of peak load reductions. We assessed more than a dozen program reviews and took the average figure for peak load reductions from these reports: a reduction of 0.13 kW per MWh saved. Using this assumption and the 2010 regional peak loads in the AEO data, we then estimated the peak load in each region and year in the Transition Scenario.

Next, we derated all wind and solar capacity (both preexisting and new) to account for the variability of these resources. We multiplied wind capacity by 15% and used regional factors to derate the solar capacity, based on an NREL study of PV energy's coincidence with peak loads in different regions (Perez 2006). We then compared derated capacity to estimated peak loads as in a traditional reserve margin analysis. Table 6 shows the 2010 margins calculated using the AEO 2010 data and the estimated margins for 2020 and 2030.[5]

[5] Note that this is a rough check of capacity adequacy, not a rigorous reserve margin analysis. A true reserve margin analysis would need to consider operating limitations on many types of generators—not just wind and solar—and it would focus on a much smaller control area than the regions addressed here.

Table 6. Estimated Reserve Margins Early in the Study Period

	2010	2020	2030
Northeast	33%	36%	50%
Southeast	45%	44%	63%
S. Central	46%	31%	41%
W. Midwest	43%	34%	35%
E. Midwest	25%	25%	49%
Northwest	58%	53%	78%
Southwest	51%	55%	74%
California	30%	31%	37%

In addition to meeting peak loads, there is great emphasis today on integrating variable generation into regional power systems. Indeed, with increasing amounts of variable generation (wind and solar), regional power systems would need to be much more flexible and responsive. In the Transition Scenario they would be.

Traditionally, large blocks of inflexible capacity (coal and nuclear plants) have been operated around the clock to meet baseload energy needs. The output of these units can be reduced somewhat, but they cannot be backed down a large amount and still remain available for the following day. System operators have had to work around these constraints, and historically, when units have been operated out of economic merit order it is often because the output of baseload units could not be reduced further.

By removing a large portion of this inflexible generation, the Transition Scenario creates much more flexibility. Flexible resources like gas and hydro units comprise larger percentages of the energy mix (although overall gas use falls). This change in the composition of supply-side resources would make power systems much more able to accommodate large amounts of variable energy than they are today. Moreover, changes in other areas will further increase flexibility.

First, rapidly growing demand response programs are making demand more responsive to prices and loads. Demand response programs with “dispatchable” components such as direct load control help to provide intra-day and intra-hour ramping capability to support greater levels of variable generation output. The introduction of dynamic pricing and potentially greater customer response to system ramping requirements also increases the flexibility of the system to respond to variable generation.

Second, system operators are moving toward much larger balancing areas and fewer total balancing areas. This supports the reduction of aggregate wind variability by capturing the spatial diversity of the wind resource base. For example, the Midwest ISO region consolidated its numerous balancing areas into a single balancing area in 2009. This has allowed for integration of wind resources without significantly increasing operating reserve requirements. The Southwest Power Pool is planning to consolidate its member utilities into a single balancing region in this decade. The Pennsylvania/New Jersey Maryland ISO (PJM) operates as a single balancing area, as do the northeastern ISOs (NY and NE).

Efforts in these three areas are already well underway. A commitment to a future like the Transition Scenario would simply reinforce and speed these changes in system planning and operation. In fact, system operation might well be easier in the Transition Scenario than it would be in the Reference Case, in which coal and nuclear plants would provide nearly 60% of the energy in 2050.

C. Changes in Net Energy Balances

An important aspect of the Transition Scenario is the way in which it would change interregional power flows, both relative to current flows and to the Reference Case future. While specific exchange levels fluctuate year to year, general patterns have emerged. We address these general patterns in terms of regional net energy balances.

Today's typical energy balances are shown in the top map in Figure 6. The width of the arrows is roughly consistent with the magnitude of the net imports or exports. The Eastern Midwest typically generates substantial excess electricity, and it is used in the Northeast and Southeast. The Northwest and Southwest also generate excess power which is consumed in California. The middle map in Figure 6 shows net energy balances in the Reference Case in 2050. (Note that NEMS does not allow interregional transfer limits to increase over the AEO study period, so increased transfers in the Reference Case are within current limits.) The Eastern Midwest delivers more energy to the Southeast and less to the Northeast. The Northwest delivers less energy to California and the Southeast delivers more.

The lower map shows 2050 energy balances in the Transition Scenario. The two best wind resources in the country are tapped and distributed. (See the wind resource map in Appendix B.) Essentially, wind generation replaces coal-fired generation in the Midwest. To manage the large percentage of wind energy in the Midwest in 2050, the two balancing areas there will need to continue improving coordination. In 2005 the Midwest ISO and PJM signed a joint operating agreement, and the two systems currently share wind forecasting and operational data.[6] With the amount of wind generation envisioned in the Transition Scenario, these two systems would need to operate in a relatively seamless way by 2050.

Energy from the south central wind resource is used there and excess is delivered to the Southeast. The Northeast becomes self sufficient by 2050. In the west, the Northwest delivers less electricity to California in 2050 than today, and more to the Southwest. The southwest transitions from being a net exporter to a net importer. In very simple terms, regions with abundant low-cost coal have historically generated excess electricity and delivered it to regions with less. In the Transition Scenario, electricity would move from regions rich in low-cost wind and hydro energy to regions with less.

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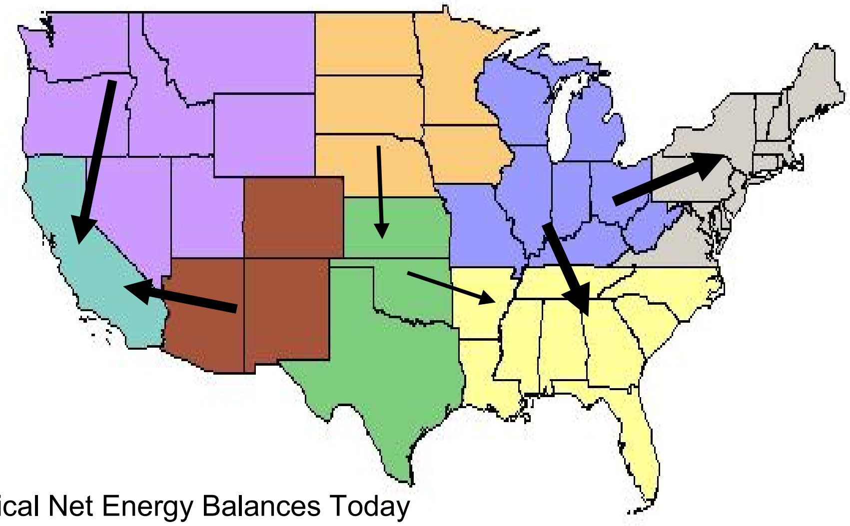
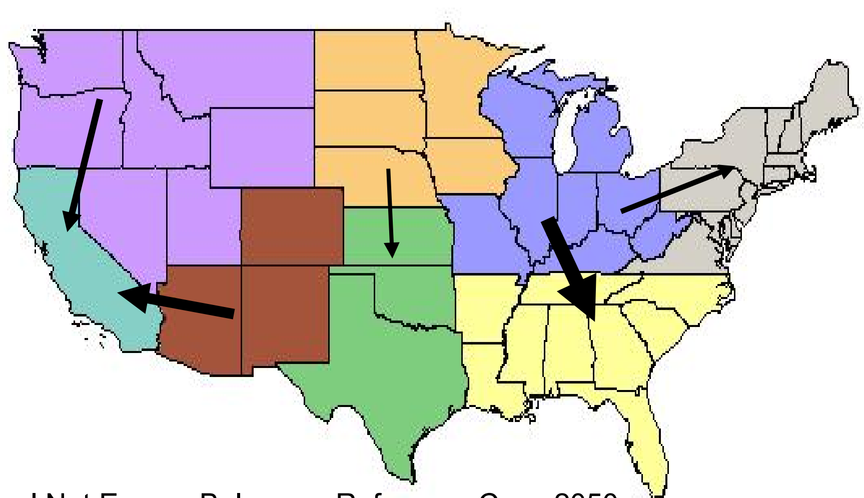
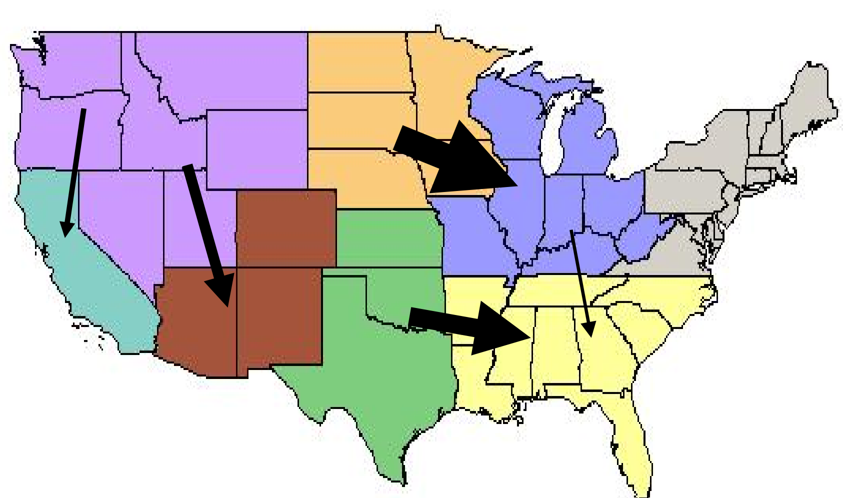
[6] The regions within the NEMS model are based on the NERC subregions, based on historical utility service territories. The national grid is now balanced by ISOs and RTOs that follow somewhat different boundaries from the NERC regions.



Typical Net Energy Balances Today



Typical Net Energy Balances: Reference Case 2050



Typical Net Energy Balances: Transition Case 2050

Figure 6. Net Electricity Balances in the Two Scenarios

Figure 6 illustrates well the fact that a future based on renewable energy would not require massive amounts of new transmission capacity to move that energy to load centers – *if* demand were suppressed with efficiency improvements and each region developed the renewable resources it has. The grid in the Midwest would need to be bolstered significantly, and interchange capacity between the South Central and Southeast regions would need to be increased. But these are modest increases over the time frame we are considering (and we include the estimated cost of these upgrades in our cost analysis).

D. Transmission Expansion

The NEMS model does not simulate the nation's transmission grid in great detail. The model includes exogenous transfer limits between regions and simulates economic power transfers within those limits. It does not recognize transmission constraints within regions or simulate power flows within regions. To approximate the cost of transmission system upgrades within regions, NEMS applies regional factors to peak loads. That is, EIA has developed assumptions for each region about the transmission system investment necessitated by each GW of growth in peak demand. These factors ($/GW) are then multiplied by regional loads each year to determine annual incremental costs.

Using the load-based factors in from NEMS, we calculate an annual cost of roughly $8 billion in 2050 for intra-regional transmission upgrades by 2050. In the Transition Scenario, loads fall rather than grow, so transmission investment would not be needed simply to move more energy, as in the Reference Case. However, intra-regional investment would be needed to bolster transmission that knits together the grid to allow variable output resources to reach all parts of a given regional grid. We make the simplifying assumption that this would cost roughly the same as the intra-regional transmission investment estimated in AEO 2010. Thus, these costs are included in both scenarios.

The NEMS model does not allow for increases in interregional transfer capabilities, so it includes no cost for such investments. In the Transition Scenario, the transmission flows in the West do not rise significantly, and we assume that transmission costs there would be similar in both scenarios. However, in the Eastern Interconnect (including ERCOT) the Transition Scenario would require investment in new, interregional transmission capacity. To estimate this cost, we estimated transmission flow allocation from one region to another in each case and used this to determine estimated interregional flows (annual TWh) to preserve the energy balances. We then compared the Transition Scenario flows to the Reference Case flows to determine the incremental energy flow requirement in the Transition Scenario. Based on these increments and estimates for the costs of new EHV transmission, we estimate total interregional transmission costs for the Transition Scenario to be in the range of $20 to $60 billion by 2050. We include the midpoint of this range in the costs of the Transition Scenario. Annualizing these costs with the same (real, levelized) fixed charge rate used for the supply-side technologies, yields $3.1 billion per year by 2050 – on top of the $8 billion per year included in the Reference Case.

E. Air and Water Impacts

The Transition Scenario provides very large emission reductions. Figure 7 shows CO_2 emissions from the electric power sector in the Reference and Transition Cases. (Emissions figures are shown in short tons throughout.) Recall that in developing the Reference Case, we extrapolated AEO 2010 emissions from 2036 to 2050, by growing or reducing emissions in each region at the average rate for the period 2012 through 2035. Where this method resulted in negative emissions in 2050, we held emissions constant in the later years.

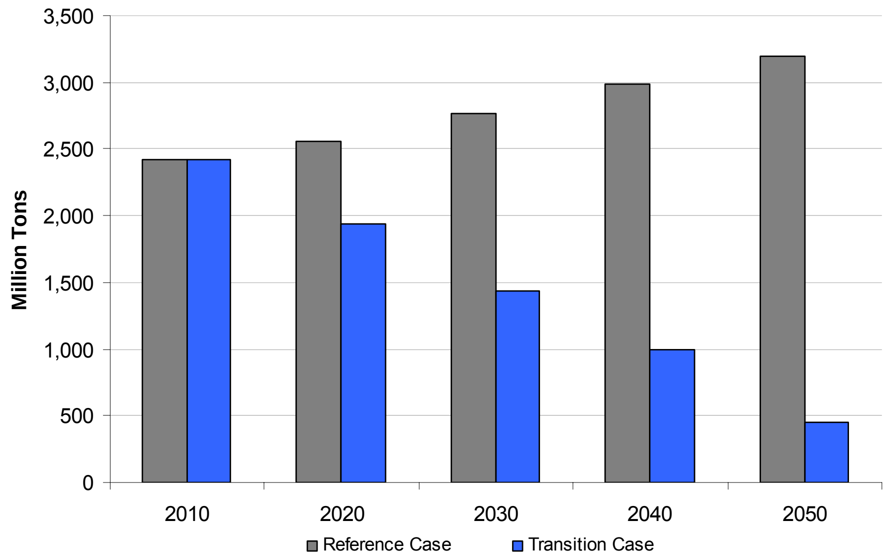


Figure 7. Electric Sector CO_2 Emissions in the Reference and Transition Cases

In the Reference Case, electric sector CO_2 emissions *increase* by nearly 770 tons or 32% over the study period. In the Transition Scenario they *fall* by 2 billion tons or 82%. Cumulative CO_2 reductions from the Transition Scenario relative to the Reference Case total 55 billion tons by 2050. Note that these reductions are relative to the 2010 power sector CO_2 emissions predicted in the AEO 2010: 2.4 billion tons. Most of the carbon reduction proposals of the last several years use 2005 as a baseline. The Transition Scenario reduces by CO_2 emissions 83% from 2005 levels, and this is very similar to the reductions called for in many recent bills, such as Waxman/Markey. However, note that most of these proposals are for economy-wide carbon caps, not power-sector only caps. Thus, it is difficult to compare these reductions directly to recent proposals in congress.

Table 7 shows other air and water impacts of the two scenarios. The table shows annual totals, not cumulative. Emissions of SO_2, NO_X, and mercury fall in the Reference Case, as NEMS simulates implementation of new air regulations, but they fall much more in the Transition Scenario. Electric sector mercury emissions are virtually eliminated by 2050 in the Transition Scenario, and emissions of SO_2 are reduced by over 95%. Electric sector water consumption grows in the Reference Case and falls in the Transition Scenario by nearly 730 billion gallons from 2010 levels.

Table 7. Air and Water Impacts in the Reference and Transition Cases

Case	2010	2050	% Change
SO_2 Reference (000 tons)	5,700	2,800	-51%
SO_2 Transition (000 tons)	5,700	150	-97%
NO_X Reference (000 tons)	2,200	2,000	-13%
NO_X Transition (000 tons)	2,200	890	-60%
Mercury Reference (tons)	41	27	-34%
Mercury Transition (tons)	41	0	-100%
*Water Reference (billion gals)	1,300	1,700	+31%
*Water Transition (billion gals)	1,300	590	-55%

*This estimate includes only water consumed, not cooling water that is returned. Water consumption is estimated from coal, nuclear, biomass, solar thermal and central PV units.

F. Net Costs of the Transition Scenario

We have estimated the net cost of the Transition Scenario relative to the Reference Case. The costs assumed for energy efficiency and the supply side technologies are detailed in Appendix B.

Table 8 shows the net annual costs of the Transition Scenario in selected years of the study period. Costs are shown in millions of constant 2009 dollars. Negative numbers, in parentheses, indicate that the Transition Scenario provides savings relative to the Reference Case. The Cost of Generation is the cost of the supply-side resources in the Transition Scenario less the cost of the same resources in the Reference Case. Costs broken out by resource are shown in Table 34, in Appendix C.

The energy efficiency investment in the Transition Scenario is the major incremental resource. Incremental transmission represents the cost of increasing transfer capabilities between regions to accommodate the increased power exchange in the Transition Scenario. Avoided emission control represents the cost of emission controls avoided by retiring coal-fired plants rather than complying with CAIR, CAVR, and CAMR during the period 2010 through 2020. As discussed in Appendix A, we assume in the Transition Scenario that coal-fired units facing large emission control investments would be retired first and thus that most of the unit retirement decisions would avoid the cost of the control systems.

Table 8. Net Cost of the Transition Scenario (million 2009$)

	2020	2030	2040	2050
Cost of Generation	($1,000)	($35,000)	($85,000)	($130,000)
Wind Integration Costs	$330	$1,600	$2,900	$3,900
Energy Efficiency	$14,000	$48,000	$79,000	$110,000
Incremental Transmission	$800	$1,600	$2,300	$3,100
Avoided Emission Control	($4,500)	($4,500)	($4,500)	$0
Total Net Cost	$9,630	$11,700	($5,300)	($13,000)
Total Net Cost (¢/kWh)	0.25	0.34	(0.17)	(0.43)

The cost of the Transition Scenario is modest in the near term, and it falls over time such that the scenario saves money relative to the Reference Case in later years. Costs are lower over the long term, for three main reasons. First, over time energy efficiency reduces generation levels relative to the Reference Case by larger and larger amounts, and efficiency costs less than supply-side resources. Second, technology improvements and market maturation reduce the cost of renewable technologies over time. There is less room for cost reductions in coal, gas and nuclear plants, because these are mature technologies. And finally, natural gas becomes very expensive in the later years of the study (as extrapolated from AEO 2010), and much less gas is burned in the Transition Scenario than in the Reference Case.

The total cost of about $10 billion in the year 2020 is quite small relative to total electric sector costs. The incremental cost of 0.25 cents/kWh in 2020 (2.5 $/MWh) is about 2.5% of the current average retail price of electricity of 10 cents/kWh. For a typical residential consumer, purchasing about 900 kWh per month, this cost increase would amount to about $2.20 per month. By 2040, the same customer would be *saving* about $1.50 per month and by 2050, saving nearly $3.90 per month.

The net present value of the incremental cost stream is $56 billion over the 40 year study period, discounted to a 2009 present value using the same rate (7.8%) as the real, levelized fixed charge rate used in calculating the annualized cost of each technology.

We characterize the net cost of the Transition Scenario as modest, particularly in the context of uncertainties in this sort of long-term analysis, and relative to the benefits of the Transition Scenario. We have not included, for example, the benefits of reducing significant climate change risks and damages, or the public health benefits associated with decreased pollution from power plants. A recent National Academies study, for example, estimated the *annual* damages, not including climate change, from the U.S. fleet of coal-fired power plants, to be $62 billion in 2005, expressed in 2007 dollars (NRC 2009). If such "externalities" are included in the benefit-cost picture, then the Transition Scenario saves society money throughout the study period.

In considering the scenario laid out here relative to other proposals for the electric power sector, it is important to include all of the benefits the scenario provides.

- Electric sector CO_2 is reduced by 82% relative to the 2010 levels predicted in AEO 2010. Reductions are 83% relative to 2005 levels, similar to most recent carbon proposals in congress.
- Emissions of other pollutants fall dramatically, with near 100% reductions in SO_2 and mercury emissions.
- The environmental impacts and safety risks of coal mining are eliminated.
- The amount of radioactive waste produced in the U.S. each year falls rather than rises, as does the risk of nuclear accidents.
- The power sector uses less natural gas, leaving more for clean cars and other uses.
- The power sector consumption of water falls by hundreds of billons of gallons.

Our hope is that this report contributes to very careful consideration of the different paths the U.S. power sector could take.

4. Implications for Regions

When looking at the regional implications of the Transition Scenario, it is important to remember that both the AEO 2010 (the basis of the Reference Case) and Transition Scenario analyses are primarily national-scale studies. That is, neither study reflects operating constraints within specific electricity balancing areas, such as constraints on transmission flows and plant dispatch. These constraints can have significant near-term impacts on when specific plants could be retired and where new capacity could be located. (Today's constraints become much less important over the longer term.)

However, both studies have addressed regional plant additions and retirements at a level sufficient to draw valid conclusions about regional differences in electricity generation and environmental impacts between the two cases. General conclusions about differences in interregional power flows between the two cases are also valid. The estimated cost impacts of the Transition Scenario, however, cannot be reliably allocated to regions, because the study focuses on the cost of producing electricity. For example, if a region generates less electricity in the Transition Scenario and imports more, generating costs would fall but purchased power costs would rise. We focus only on changes in the total cost of generation.

The regions used in this study are based on the 13 regions within the Electricity Market Module (EMM) of the NEMS model. These regions are shown in Figure 17. To simplify the analysis, we have consolidated these thirteen regions into eight. Our Northeast region includes EMM regions 3, 6 and 7. Our Southeast includes regions 8 and 9. Our Eastern Midwest includes regions 1 and 4, and our South Central includes regions 2 and 10.

Figure 8 shows the approximate boundaries of our study regions, following state lines. The regions within NEMS do not follow state lines exactly, so refer to Figure 17 to see the precise regional boundaries.

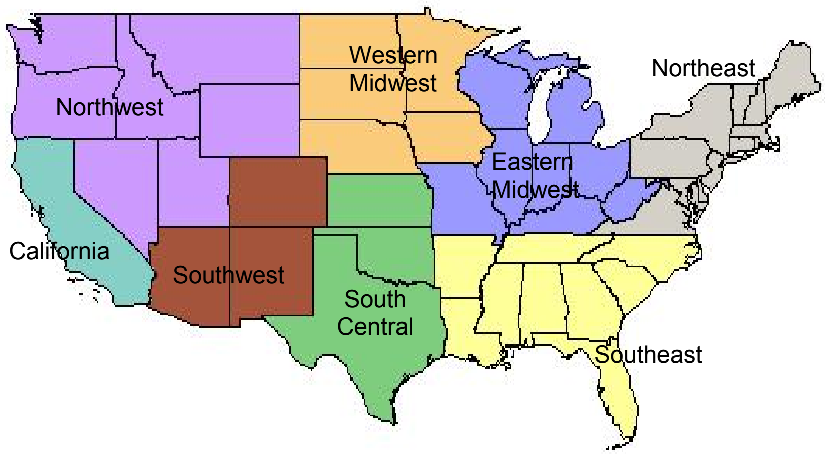


Figure 8. The Regions of the Study

A. The Northeast

This region covers New England, New York, and the Mid-Atlantic, including most of Pennsylvania and Virginia.[7] As seen in Figure 9, today the Northeast is heavily dependent on nuclear power (34% of energy), with coal (27%) and gas (23%) also contributing heavily to the energy mix. Wind energy is the region's most attractive renewable resource in terms of abundance and cost. The potential of solar PV is great, but costs are considerably higher than wind costs. The Northeast also has a reasonable biomass resource: roughly 5% of the cellulosic biomass potential we use and 14% of the waste gas potential.

Historically, the Northeast has been a net importer of electricity, importing primarily from the Midwestern U.S. and Canada. In AEO 2010 the region imports 40 TWh in 2010 from U.S. regions and 15 TWh from Canada, totaling about 10% of total electricity use. (In the Transition Scenario, we hold international imports constant throughout the study period.)

As shown in Figure 9, growing demand in the Reference Case causes generation in the Northeast to grow by 52% over the study period to over 830 TWh in 2050. As generation grows, the region becomes more dependent on fossil fuels and nuclear power. Generation from gas increases to become 29% of the energy mix in 2050, and coal and nuclear become 23% and 26% respectively. The Reference Case includes a new nuclear plant of 1,300 MW in the MidAtlantic area of the Northeast, coming online in 2019. Biomass and wind energy also expand considerably, becoming 10% and 5% of the energy mix respectively. The Northeast also imports less energy from the Midwest in the Reference Case: net electricity imports fall from 40 to 18 TWh over the study period.

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[7] The region is a consolidation of the NERC subregions NPCC New England, NPCC New York and MAAC.

In the Transition Scenario, energy efficiency reduces demand from 2010 levels, allowing total generation in the Northeast to fall by 38 TWh (7%) by 2050. While generation falls, the region becomes even more self sufficient than in the Reference Case. Net imports fall from 40 TWh in 2010 to essentially zero in 2050. This is an important aspect of this scenario. Aggressive efficiency and development of off-shore wind mean that this region does not have to continue to rely on the Midwest for electricity. Other key aspects of the Transition Scenario are as follows:

- The region retires all of its coal-fired generating capacity – over 27,000 MW.
- 17,000 MW of nuclear capacity (72%) is retired, and nuclear generation is reduced by 140 TWh (72%).
- Natural gas becomes a larger percentage of the electricity fuel mix, however total 2050 generation from gas is 59 TWh lower in the Transition Scenario than in the Reference Case.
- There are over 25,000 MW of onshore wind capacity and 16,000 MW of offshore wind from Virginia to Maine. Wind energy is 31% of the energy mix in 2050.
- There are 14,000 of solar PV capacity, providing 6% of generation and 1,400 MW of biomass capacity providing 7%.
- Waste gases are utilized effectively, with landfill, wastewater treatment, and farm digester gases providing 2% of the region's electricity. (This energy is included in Biomass in Figure 9.)
- Electricity imports have fallen from 40 TWh in 2010 to roughly zero in 2050.

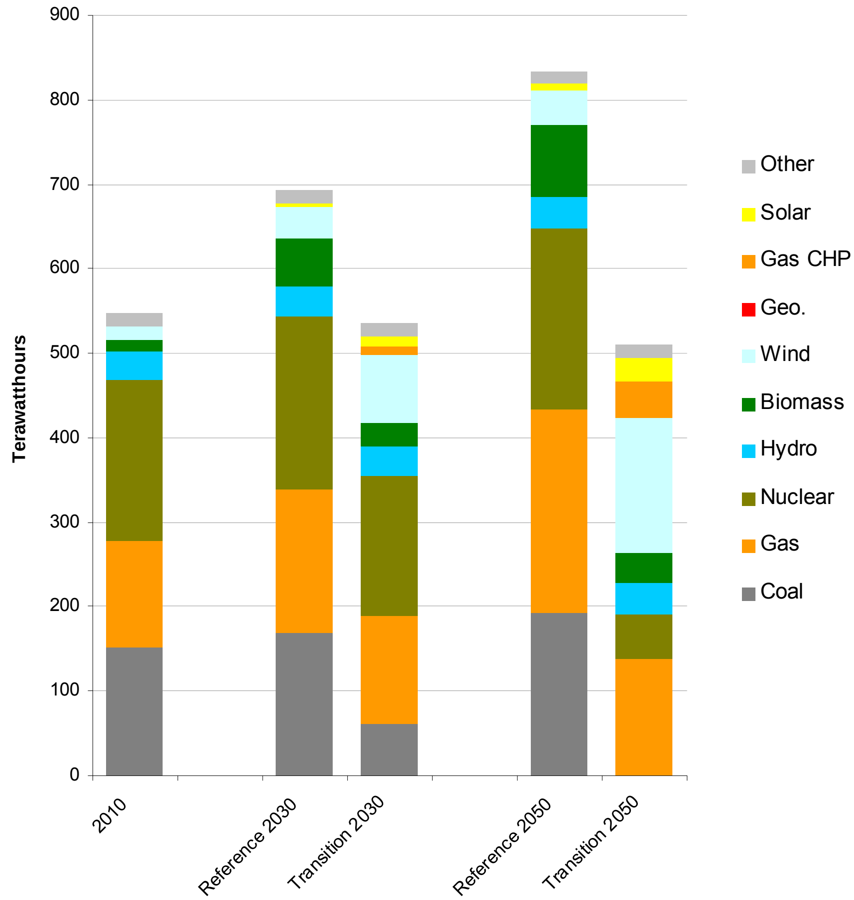

Figure 9. The Northeast in the Reference and Transition Cases

Table 9 shows the air impacts of the Reference and Transition Cases in the Northeast. The figures shown are annual totals for 2010 and 2050. Electric sector emissions of CO_2 rise in the Reference Case and fall in the Transition Scenario. Cumulative CO_2 reductions from the Transition Scenario relative to the Reference Case total nearly 4.9 billion tons by 2050. Emissions of SO_2 and mercury fall in the Reference Case, as NEMS simulates implementation of new air regulations, but they fall much more in the Transition Scenario due to the phase-out of coal. Emissions of mercury are virtually eliminated, and emissions of SO_2 are reduced by 95%. Emissions of NO_X rise in the Reference Case, presumably as increased gas-fired generation offsets reductions from new controls on coal-fired plants.

Table 9. Air Impacts in the Northeast

Case	2010	2050	% Change
CO_2 Reference (000 tons)	230,000	310,000	+35%
CO_2 Transition (000 tons)	230,000	78,000	-66%
SO_2 Reference (000 tons)	750	330	-56%
SO_2 Transition (000 tons)	750	38	-95%
NO_X Reference (000 tons)	200	210	+5%
NO_X Transition (000 tons)	200	130	-35%
Mercury Reference (tons)	5.4	1.7	-69%
Mercury Transition (tons)	5.4	0.0	-100%

B. The Southeast

Today the Southeast is heavily dependent on coal, gas, and nuclear generation. These three fuels make up over 90% of the generating fuel mix. The Southeast is also large and heavily populated, and electricity loads – especially summer loads – are very high. Annual electricity use is currently in the range of 1,000 TWh, roughly 28% of total national use. The region typically imports about 3% to 5% of the electricity it uses, primarily from the Midwest: in AEO 2010 the region imports 42 TWh in 2010. Solar energy is the region's most abundant renewable resource. The region also has an ample biomass potential: 20% of our national total for cellulosic and 17% of waste gas potential. The region has some wind potential, but much less wind than one would expect given its size.

As shown in Figure 10, growing demand in the Reference Case causes generation in the Southeast to grow to over 1,600 TWh in 2050. Electricity imports rise. Generation from coal, nuclear, and gas plants increases substantially, and electricity imports rise as well. Over 7,500 MW of coal-fired generation are added as well as nearly 6,000 MW of new nuclear capacity. The Reference Case includes strong development of the biomass resource. Wind and solar generation grow modestly, with these resources becoming only 1% and 0.4% of the mix in 2050.

In the Transition Scenario, aggressive efficiency programs push down load growth, and solar and wind resources are developed more aggressively. In contrast, the biomass resource is developed less aggressively than in the Reference Case. Electricity imports into the Southeast rise much more than in the Reference Case, reaching 80 TWh in 2050. Key aspects of the strategy in the Southeast are as follows:

- Coal-fired generation is eliminated: 82,500 MW are retired.
- Nuclear generation remains relatively unchanged.
- Gas-fired generation grows by 100 TWh from 2010 levels, but by 2050 it is still 25 TWh below Reference Case levels. Most of the growth in gas-fired generation comes from CHP plants.
- The region imports much more electricity, primarily wind energy from the South Central region.

- 6,300 MW of onshore wind capacity are added by 2050 and 11,000 MW offshore. Wind energy accounts for 7% of the in-region generation.
- In 2050, 14,000 MW of solar capacity are producing 4% of the in-region generation.
- Over 4,500 MW of direct-fire biomass capacity are added and 1,300 MW of biomass-fired CHP. The region produces 82 TWh of electricity from biomass in 2050. In the Reference Case, the region produces 159 TWh from biomass.
- Waste gases provide over 18 TWh in 2050. (This energy is included in Biomass in Figure 10.)

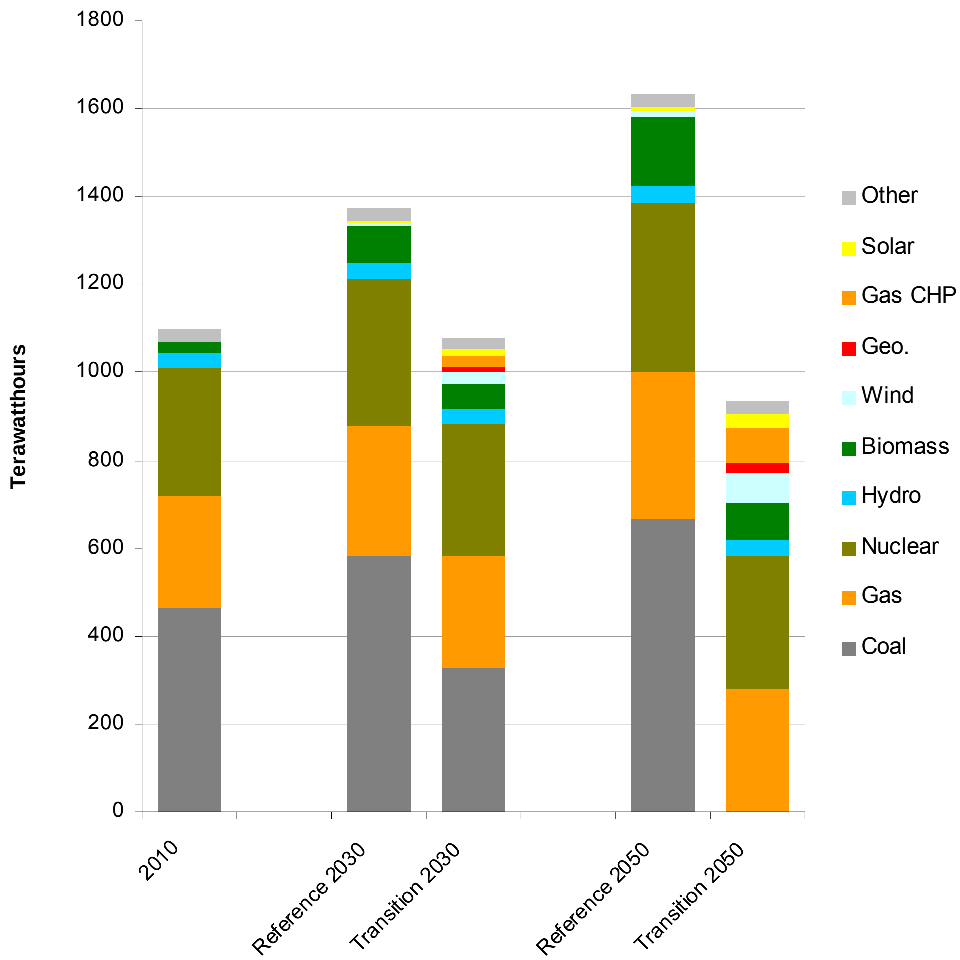

Figure 10. The Southeast in the Reference and Transition Cases

Table 10 shows the air impacts of the Reference and Transition Cases in the Southeast. The figures shown are annual totals for 2010 and 2050. Electric sector emissions of CO_2 rise in the Reference Case and fall in the Transition Scenario. Cumulative CO_2 reductions from the Transition Scenario relative to the Reference Case total nearly 15 billion tons by 2050.

Emissions of SO_2 and NO_X fall in the Reference Case, as NEMS simulates implementation of new air regulations, however emissions of these pollutants fall much more in the Transition Scenario due to the phase-out of coal. Emissions of mercury rise in the Reference Case, presumably because within NEMS, increased coal-fired generation offsets reductions from plants at which controls are installed. Power sector mercury emissions are virtually eliminated in the Transition Scenario, and emissions of SO_2 are reduced by 94%.

Table 10. Air Impacts in the Southeast

Case	2010	2050	% Change
CO_2 Reference (000 tons)	640,000	850,000	+33%
CO_2 Transition (000 tons)	640,000	160,000	-76%
SO_2 Reference (000 tons)	1,400	820	-41%
SO_2 Transition (000 tons)	1,400	86	-94%
NO_X Reference (000 tons)	480	410	-15%
NO_X Transition (000 tons)	480	270	-44%
Mercury Reference (tons)	7.4	7.7	+4%
Mercury Transition (tons)	7.4	0.0	-100%

C. The Eastern Midwest

A very large portion of the country's coal-fired generation is located in the Eastern Midwest. In AEO 2010, coal-fired plants generate nearly 70% of the region's electricity in 2010, and coal, nuclear, and gas together make up 97%. The region is by far the largest exporter of electricity in the country, typically exporting on the order of 70 TWh, primarily to the Northeast and Southeast. The Eastern Midwest has a vast wind resource, although it has fewer high-class wind sites than the Western Midwest and the South Central. The region also has a very large biomass resource: 31% of our national total for cellulosic biomass and 26% of our national waste gas total. In the Reference Case, much of this biomass resource is tapped, but little of the wind resource is. The region continues to rely on primarily on coal, gas and nuclear energy.

Figure 11 compares the Eastern Midwest in the Reference and Transition Cases in the years 2010, 2030, and 2050. In the Transition Scenario, the Eastern Midwest becomes much more energy efficient; it taps its massive wind resource; and the generating fuel mix becomes much more diverse. The region replaces it coal-fired generation primarily with wind, gas-fired CHP plants and biomass, but the region also becomes a net electricity importer, importing considerable amounts of wind energy from the Western Midwest.

By 2050, the Eastern and Western Midwest are operating in a highly coordinated way, balancing the wind generation across this vast area with gas-fired and other resources. The Midwestern system operators are already heading down this path. With the Joint Operating Agreement signed in 2005 The Midwest ISO and the Pennsylvania/New Jersey/ Maryland Interconnection (PJM) are moving toward more seamless operation.

Other key aspects of the Transition Scenario are as follows:

- All coal-fired capacity (116,000 MW) is retired.

- Gas generation grows by 95 TWh from 2010 levels, with most of the increase coming at CHP plants. This region and its neighbor to the west are the only two regions in which natural gas use increases in the Transition Scenario more than in the Reference Case.
- The region develops its wind resource, adding 51,000 MW of wind capacity by 2050. Wind energy becomes 29% of the generating mix.
- Biomass generation levels are similar in the Transition and Reference Cases.
- No nuclear capacity is retired.

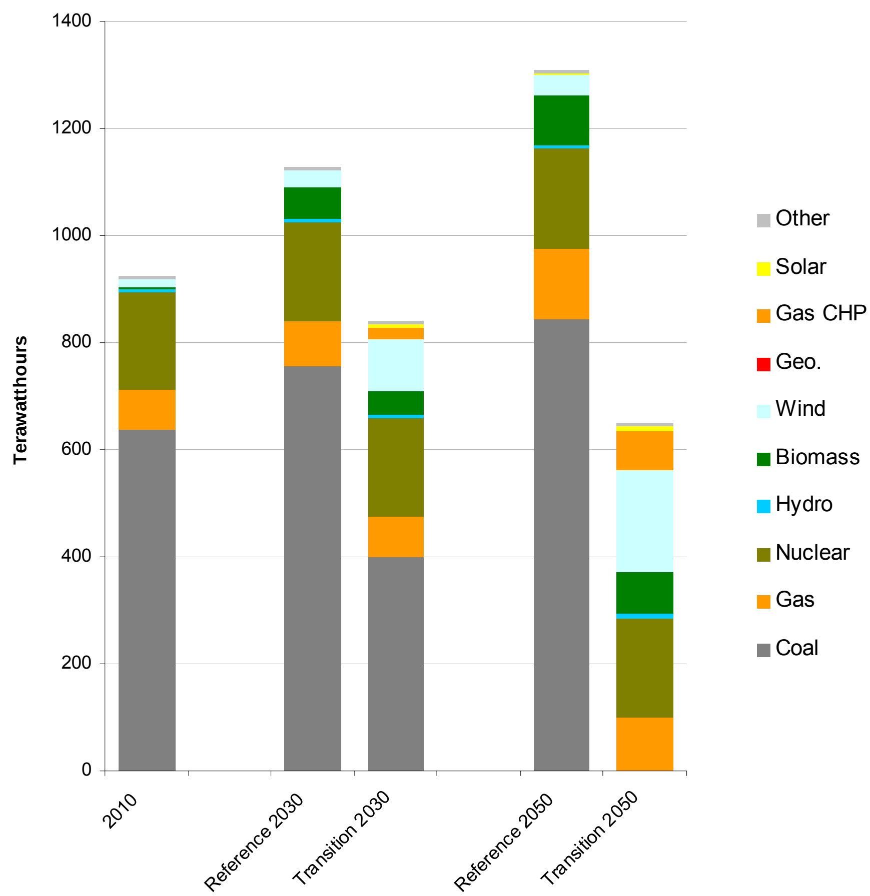

Figure 11. The Eastern Midwest in the Reference and Transition Cases

Table 11 shows the air impacts of the Reference and Transition Cases in the Eastern Midwest. The figures shown are annual totals for 2010 and 2050. Electric sector emissions of CO_2 rise in the Reference Case and fall in the Transition Scenario. Cumulative CO_2 reductions from the Transition Scenario relative to the Reference Case total nearly 15 billion tons by 2050. Emissions of SO_2, NO_x, and mercury fall in the Reference Case, as NEMS simulates implementation of new air regulations, but they fall much more in the Transition Scenario due to the phase-out of coal. Note that although

2050 gas-fired generation is higher in the Transition Scenario than the, Reference Case, NO_x emissions fall much more than in the Transition Scenario. Electric sector mercury emissions are virtually eliminated in the Transition Scenario, and emissions of SO_2 are reduced by nearly 100%.

Table 11. Air Impacts in the Eastern Midwest

Case	2010	2050	% Change
CO_2 Reference (000 tons)	730,000	940,000	+29%
CO_2 Transition (000 tons)	730,000	63,000	-91%
SO_2 Reference (000 tons)	2,500	890	-64%
SO_2 Transition (000 tons)	2,500	11	-99%
NO_X Reference (000 tons)	570	390	-32%
NO_X Transition (000 tons)	570	190	-67%
Mercury Reference (tons)	13	4.6	-65%
Mercury Transition (tons)	13	0	-100%

D. The Western Midwest

The Western Midwest also relies very heavily on coal for its electricity. Coal currently provides nearly 70%, with nuclear providing roughly 15%, and gas providing less than 5%. Hydropower currently provides about 7%. In recent years the region has been a net electricity exporter: in the Reference Case it exports 13 TWh in 2010. The region has a vast wind resource, with many high-class wind sites that could produce low-cost energy. The region also has a very large biomass resource: 24% of our total for cellulosic biomass and 10% of our total for waste gases.

In the Reference Case, demand grows by 1% per year on average, and generation grows by 72% over the study period. Electricity exports rise significantly in the near term, but fall back to current levels by 2035. Generation from coal rises by 44 TWh by 2010 as existing coal plants produce more and 1,800 MW of new coal capacity is added. As seen in Figure 12, generation from Biomass grows by 82 TWh over the study period to become 27% of the energy mix. Remarkably, the region’s massive wind resource remains virtually untapped, and wind energy falls from 6 to 3% of the energy mix.

In the Transition Scenario, energy efficiency pushes demand in the region down over the study period, but regional generation increases considerably, as the huge wind resource is developed. By 2050, the Eastern and Western Midwest are operating in a highly coordinated way, balancing the wind generation across this vast area with gas-fired and other resources. As discussed above, we assume that the Midwestern system operators continue their current efforts to coordinate operations and by 2050 they are operating in a very seamless way. Key aspects of the Transition Scenario include the following:

- Over 20,000 MW of coal-fired capacity are retired.
- Gas-fired generation grows by 9 TWh, with most of the growth coming from new CHP plants. The Eastern and Western Midwest are the only two regions in which natural gas use increases in the Transition Scenario more than in the Reference Case.

- Wind energy increases by 130 TWh (over 700%), as 32,000 MW are added. Most of this wind-generated electricity is used in the Eastern and Western Midwest; a small amount of it – less than 10 TWh – is delivered to the Southeast.
- The region's biomass resource is not developed as aggressively as in the Reference Case. Biomass capacity (not including waste gases) grows by 11,000 MW in the Reference Case and 6,400 MW in the Transition Scenario.
- Waste gases generate over 8 TWh of electricity in the Transition Scenario compared to only 1 TWh in the Reference Case. There is strong growth in generation from farm-based methane capture (ADG systems).
- No nuclear capacity is retired.

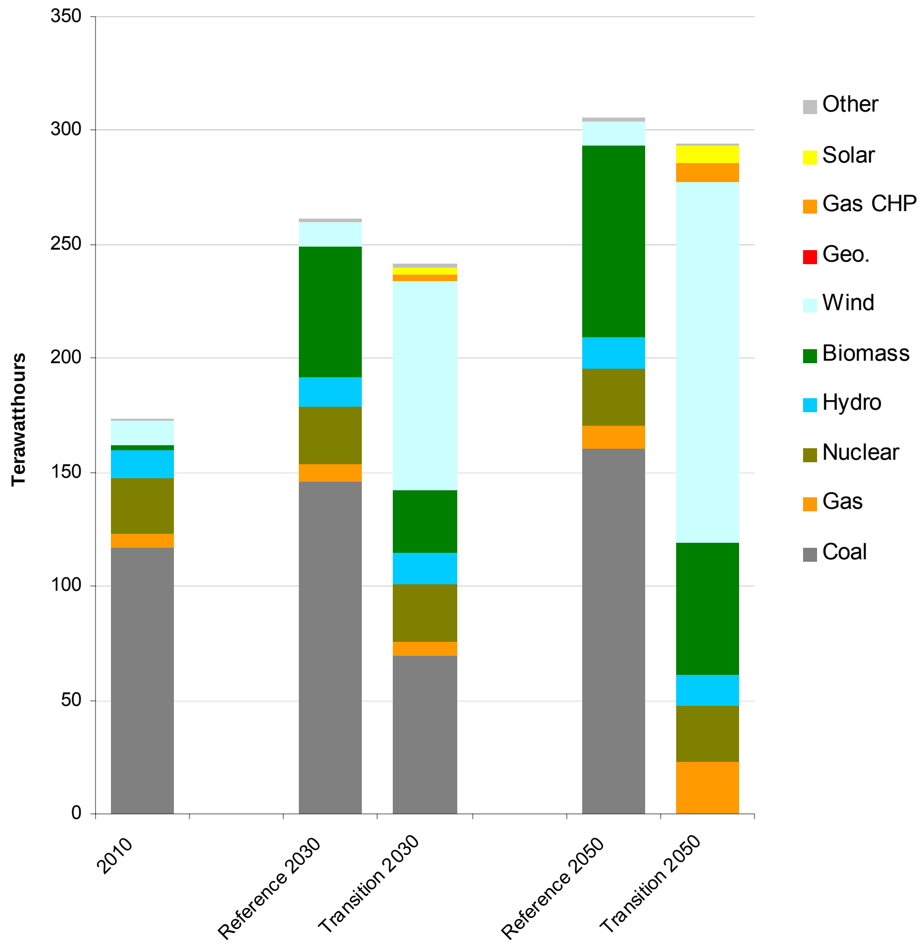

Figure 12. The Western Midwest in the Reference and Transition Cases

Table 12 shows the air impacts of the Reference and Transition Cases in the Western Midwest. The figures shown are annual totals for 2010 and 2050. Electric sector emissions of CO_2 rise in the Reference Case and fall in the Transition Scenario.

Cumulative CO_2 reductions from the Transition Scenario relative to the Reference Case total over 2.1 billion tons by 2050.

Emissions of SO_2 and NO_X fall in the Reference Case, as NEMS simulates implementation of new air regulations, but they fall much more in the Transition Scenario due to the phase-out of coal. In particular, note that although 2050 gas-fired generation is higher in the Transition Scenario than the, Reference Case, NO_x emissions fall much more than in the Transition Scenario. Emissions of mercury rise in the Reference Case, presumably because within NEMS, increased coal-fired generation offsets reductions from plants at which controls are installed. Power sector mercury emissions are virtually eliminated in the Transition Scenario, and emissions of SO_2 are reduced by 99%.

Table 12. Air Impacts in the Western Midwest

Case	2010	2050	% Change
CO_2 Reference (000 tons)	130,000	170,000	31%
CO_2 Transition (000 tons)	130,000	9,000	-93%
SO_2 Reference (000 tons)	320	180	-44%
SO_2 Transition (000 tons)	320	3	-99%
NO_X Reference (000 tons)	220	150	-32%
NO_X Transition (000 tons)	220	83	-62%
Mercury Reference (tons)	3.3	3.8	15%
Mercury Transition (tons)	3.3	0	-100%

E. The South Central Region

The South Central region includes most of Texas, Oklahoma, and Kansas. Currently, the region is heavily dependent on coal and gas for its electricity. These two fuels typically account for over 80% of all generation in the region. The power system in Texas is largely isolated from the rest of the U.S., so little power is imported and exported. The region has a very large wind resource, and this resource is currently being developed aggressively in Texas. The solar resource is also extensive, including both PV and solar thermal potential. There is also a small geothermal potential, primarily in “co-produced” projects that access hot water in gas and oil drilling operations. The biomass resource is quite large also: 12% of our total cellulosic biomass potential and 11% of our total waste gas potential.

In the Reference Case, demand grows at an average rate of 1% per year, driving an increase in generation of 176 TWh or 32% by 2050. The Oklahoma/Kansas region imports much more electricity over the study period. As seen in Figure 13, coal and gas remain the dominant fuels in the Reference Case. Nuclear generation grows by roughly 20 TWh, as 2,300 MW of new nuclear capacity are added, and the region’s wind and solar resources remain largely undeveloped.

In the Transition Scenario, aggressive energy efficiency programs push demand down over the study period, allowing the region to generate less electricity and to export much more. The region develops its massive wind resource and increases its exports to the Southeast. Exports rise from 8 TWh in 2010 to 74 TWh in 2050. Other key aspects of the Transition Scenario include the following:

- All coal-fired capacity (42,000 MW) is retired.
- Nuclear generation is reduced by 22 TWh, or 45%, as 2,500 MW of nuclear capacity are retired.
- Gas-fired generation increases by 23 TWh, with the entire increase coming at CHP plants. Gas generation increases by 70 TWh in the Reference Case.
- The region taps its low-cost wind resource, adding 39,000 MW of new wind capacity by 2050. In 2050 the region generates 190 TWh of wind energy, or 36% of total generation.
- Electricity exports rise substantially, as excess wind energy is exported to the Southeast.
- Solar and geothermal resources have also been tapped. Over 9,300 MW of solar capacity generates 5% of total energy, and 3,600 MW of geothermal capacity also generates 5%. Biomass energy accounts for 4% of generation.
- Waste gases are being utilized effectively, providing nearly 10 TWh (2%) in 2050.

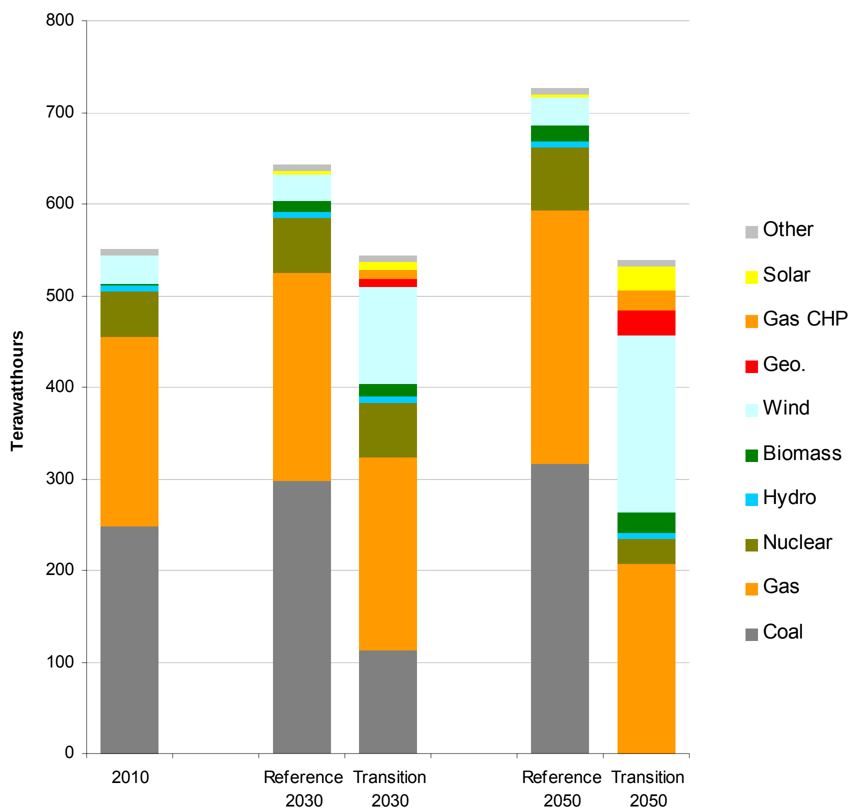

Figure 13. The South Central Region in the Reference and Transition Cases

Table 13 shows the air impacts of the Reference and Transition Cases in the South Central region. The figures shown are annual totals for 2010 and 2050. Electric sector emissions of CO_2 rise in the Reference Case and fall in the Transition Scenario. Cumulative CO_2 reductions from the Transition Scenario relative to the Reference Case total over 7.8 billion tons by 2050. Emissions of SO_2, NO_x, and mercury fall in the Reference Case, as NEMS simulates implementation of new air regulations, but they fall much more in the Transition Scenario due to the phase-out of coal. Mercury is virtually eliminated, and of SO_2 is reduced by 98%.

Table 13. Air Impacts in the South Central Region

Case	2010	2050	% Change
CO_2 Reference (000 tons)	370,000	450,000	+22%
CO_2 Transition (000 tons)	370,000	93,000	-75%
SO_2 Reference (000 tons)	580	330	-43%
SO_2 Transition (000 tons)	580	9	-98%
NO_X Reference (000 tons)	360	280	-22%
NO_X Transition (000 tons)	360	130	-64%
Mercury Reference (tons)	7.2	6.9	-4%
Mercury Transition (tons)	7.2	0	-100%

F. The Northwest

The Northwest has vast amounts of renewable energy resources. The region's ample hydroelectric resources were well developed in the 1950s and 1960s. Northwestern hydro projects currently generate on the order of 130 TWh of energy annually or nearly half of the region's generation. In addition to hydropower, the region has very large wind, and geothermal resources, which remain largely untapped. Today, the Northwest exports substantial amounts of power to California in the summer and imports from California in the winter. In recent years, the region has had net exports on the order of 30 TWh.

Figure 14 compares the Northwest energy mix in the Reference and Transition Cases in 2010, 2030, and 2050. In the Reference Case, demand grows by 1.2% per year on average, and generation increases by over 110 TWh (41%) in 2050. Coal-fired generation increases by 25 TWh (34%), and gas-fired generation increases by 27 TWh (60%). Hydro generation increases by 24 TWh or 19%, due to upgrades at existing dams. Wind generation increases by only 63 TWh to become 9% of the region's generation in 2050. Biomass-fired generation becomes 5%, and the region's net exports fall to 10 TWh in 2050.

In the Transition Scenario, aggressive energy efficiency in the Northwest pushes down demand, and the region develops its renewable resources more aggressively. The region also exports more electricity over time, not less, with net exports rising from 31 TWh in 2010 to 53 TWh in 2050. Key aspects of the Transition Scenario in the Northwest include the following:

- All coal and nuclear capacity is retired – 11,800 MW of coal and 1,100 MW of nuclear.

- Gas-fired generation is not only lower than in the Reference Case, it falls by 33 TWh (74%) relative to 2010 levels.
- Hydro generation increases modestly, as in the Reference Case. The increase is primarily due to upgrades at existing dams.
- The region adds 12,000 MW of onshore wind capacity, a relatively modest development of the resource. Wind energy increases by 63 TWh to become 27% of generation.
- 1,800 MW of geothermal capacity is added, and this resource provides 6% of energy in 2050. Only CHP biomass is added (430 MW) bringing total biomass generation up to 5% of regional generation.
- Biomass- and gas-fired CHP plants generate 7 TWh (2%) in 2050. Waste gases also produce 7 TWh in 2050.

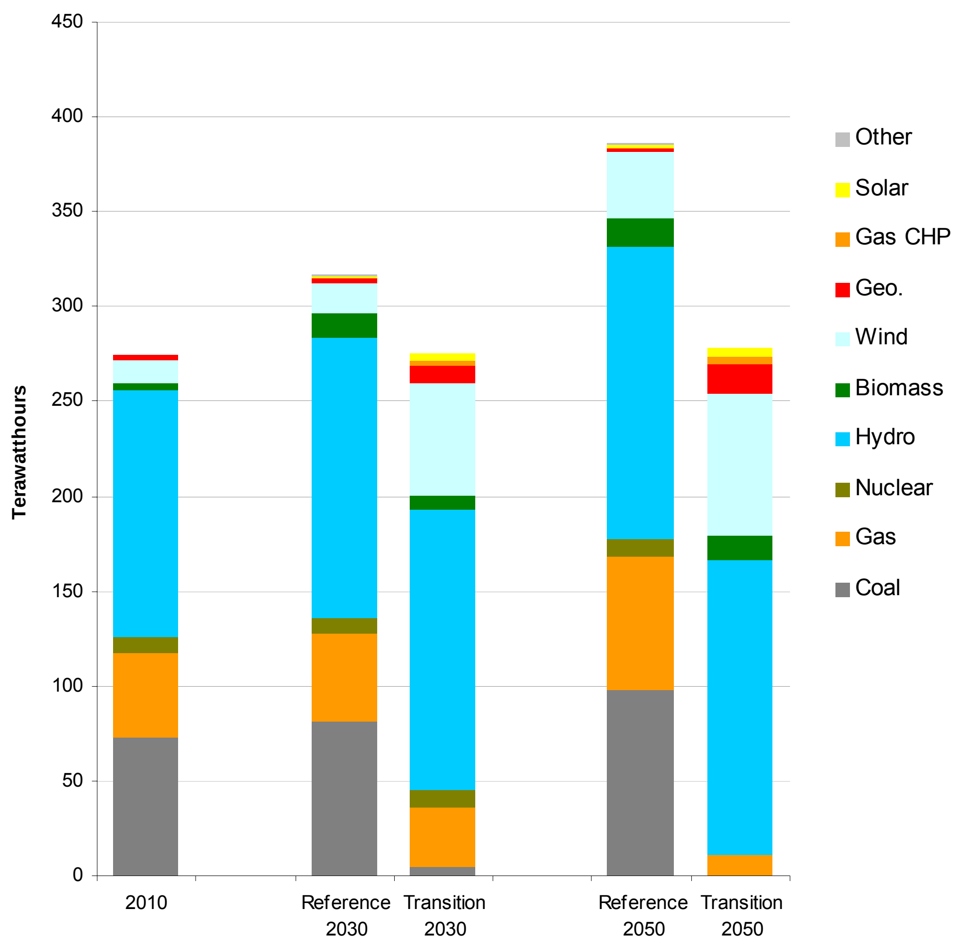

Figure 14. The Northwest in the Reference and Transition Cases

Table 14 shows the air impacts of the Reference and Transition Cases in the Northwest. The figures shown are annual totals for 2010 and 2050. Electric sector emissions of CO_2

rise in the Reference Case and fall in the Transition Scenario. Cumulative CO_2 reductions from the Transition Scenario relative to the Reference Case total nearly 3.1 billion tons by 2050.

Emissions of SO_2 and NO_X fall in the Reference Case, as NEMS simulates implementation of new air regulations, but they fall much more in the Transition Scenario due to the phase-out of coal. Emissions of mercury stay essentially flat in the Reference Case, while they are virtually eliminated in the Transition Scenario. Emissions of SO_2 are reduced by 99%.

Table 14. Air Impacts in the Northwest

Case	2010	2050	% Change
CO_2 Reference (000 tons)	100,000	130,000	30%
CO_2 Transition (000 tons)	100,000	6,000	-94%
SO_2 Reference (000 tons)	100	98	-2%
SO_2 Transition (000 tons)	100	1	-99%
NO_X Reference (000 tons)	130	160	23%
NO_X Transition (000 tons)	130	20	-85%
Mercury Reference (tons)	1.5	1.5	0%
Mercury Transition (tons)	1.5	0	-100%

G. The Southwest

This region includes Arizona, New Mexico, Colorado, and the southern tip of Nevada. Today the region gets a majority of its electricity from coal- and gas-fired plants. It typically exports on the order of 25 TWh annually, most if it to California. The region has a massive solar resource and reasonably large wind resource, with much of the wind in Colorado. It also has a considerable geothermal resource.

Figure 15 compares the Southwest energy mix in the Reference and Transition Cases in 2010, 2030, and 2050. In the Reference Case, load grows at an average rate of 1.5% annually, faster than many other regions in the country. To meet this growth, the region expands it coal-fired generation substantially. Energy from coal grows by over 110 TWh (94%), while gas-fired generation grows by 12 TWh (19%) and nuclear generation does not increase. Wind and biomass generation both expand, each becoming 3% of the mix. The region's power exports stay relatively stable.

In the Transition Scenario, energy efficiency pushes demand down, and the Southwest becomes a net importer of electricity from the Northwest. Imports are 19 TWh in 2050. In-region generation from wind, geothermal, and solar energy grows, while all coal and nuclear units are retired. Key aspects of this scenario are as follows:

- Instead of expanding, coal-fired generation is eliminated, as 18,000 MW are retired.
- All nuclear capacity (2,900 MW) is also retired.

- Generation from central-station gas plants falls, while generation from gas-fired CHP plants grows. Overall, gas-fired generation grows very little relative to 2010 levels, and it is 12 TWh below Reference Case levels in 2050.
- Wind provides 20% of generation, with 7,800 MW added over the study period.
- The region has developed its solar resource, with much of the development in Nevada. Over 7,000 MW of PV capacity have been added by 2050, generating 8% of the electricity. Roughly 5,500 MW of solar thermal capacity has come on line, providing 13% of the generation.
- 1,900 MW of geothermal capacity have been added, providing 8% of the generation.
- Waste gases, primarily landfill and farm digester gases, provide nearly 2% of the generation in 2050.

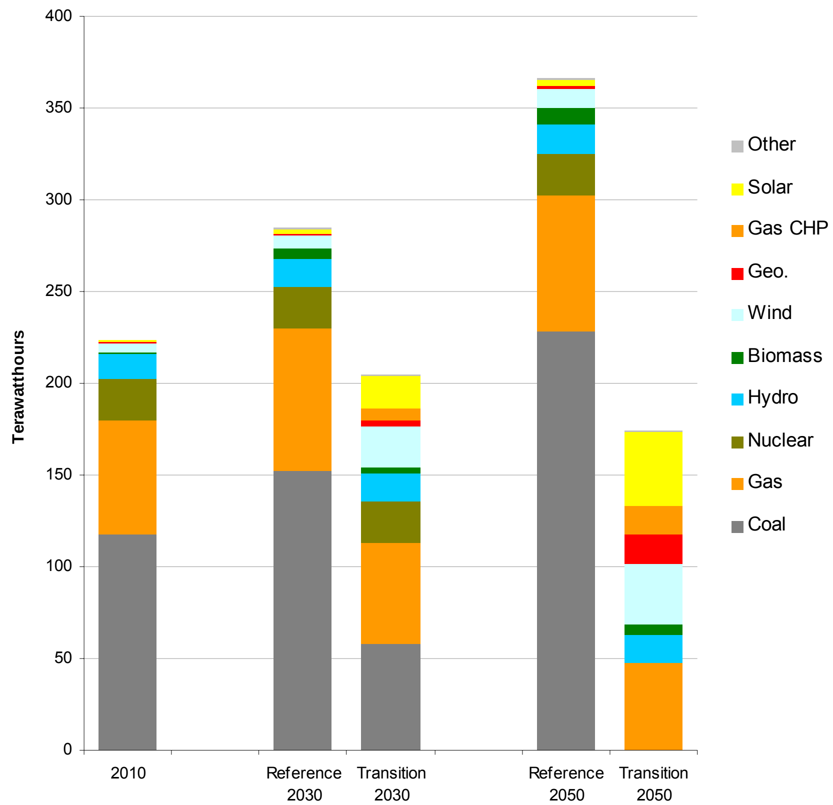

Figure 15. The Southwest in the Reference and Transition Cases

Table 15 shows the air impacts of the Reference and Transition Cases in the Southwest. The figures shown are annual totals for 2010 and 2050. Electric sector emissions of CO_2 rise in the Reference Case and fall in the Transition Scenario. Cumulative CO_2 reductions from the Transition Scenario relative to the Reference Case total over 4.7 billion tons by 2050.

Emissions of SO_2, NO_x, and mercury fall in the Reference Case, as NEMS simulates implementation of new air regulations, but they fall much more in the Transition Scenario due to the phase-out of coal. Power sector mercury emissions are virtually eliminated in the Transition Scenario, and emissions of SO_2 are reduced by 97%.

Table 15. Air Impacts in the Southwest

Case	2010	2050	% Change
CO_2 Reference (000 tons)	160,000	270,000	69%
CO_2 Transition (000 tons)	160,000	24,000	-85%
SO_2 Reference (000 tons)	104	140	35%
SO_2 Transition (000 tons)	104	4	-97%
NO_X Reference (000 tons)	210	280	33%
NO_X Transition (000 tons)	210	50	-76%
Mercury Reference (tons)	2.1	0.7	-67%
Mercury Transition (tons)	2.1	0.0	-100%

H. California

California currently uses much more electricity than it generates, with the imports coming from both the Northwest and the Southwest regions. There are no coal-fired power plants in the state, but one in Nevada is directly connected to the state's transmission grid and delivers most of its energy to California. Most models, including NEMS, count this plant as part of the California power system.

The fuel mix of California's electricity generation is fairly diverse. Gas typically accounts for roughly 33% of annual energy, nuclear for 19%, and hydro for 15%. Coal and wind each account for about 10%, and most of the existing geothermal capacity in the country is in California, providing roughly 6% of annual energy. The state has considerable renewable resources, including ample undeveloped wind and geothermal resources and a massive solar resource.

Figure 16 compares the California energy mix in the Reference and Transition Cases in 2010, 2030, and 2050. In the Reference Case, electricity use grows by 1.1% annually, and California generates much more electricity, reducing net imports substantially. The largest increase comes in wind generation, as the state adds 16,000 new MW. Wind energy grows to become 22% of the mix in 2050, and gas-fired generation increases to become 33%. Coal-fired generation rises slightly, and nuclear generation remains at historical levels. Solar energy becomes 3% of the 2050 mix, and modest growth in geothermal makes this resource 8% of the mix.

In the Transition Scenario, California also generates more of the electricity it uses, however the resource development path is quite different. Efficiency efforts continue to reduce load growth. Note that the California utilities are currently among the most effective in the nation at saving energy, and the state's current efficiency targets would produce *greater* energy savings than we assume in the Transition Scenario. Reliance on fossil fuels and nuclear energy falls, and renewable resources are developed in a more balanced way. Key aspects of this scenario include the following:

- Coal-fired generation is eliminated by 2020 (3,400 MW), and nuclear is eliminated by 2050 (5,500 MW).
- Annual gas-fired generation falls by 39 TWh (53%) relative to 2010 levels. In the Reference Case, gas-fired generation increases by 51 TWh (69%).
- California's wind resource is not developed as aggressively in the Transition Scenario than in the Reference Case. Roughly 8,200 MW are added in the Transition Scenario, generating 70 TWh in 2050. In the Reference Case, 16,500 MW are added.
- California's geothermal and solar resources are more fully developed than in the Reference Case. Geothermal capacity grows by 2,600 MW and produces 14% of generation in 2050. Solar capacity grows by 7,900 MW and produces 10%
- 1,600 MW of biomass- and gas-fired CHP produces 12 TWh of electricity (5%).
- Waste gases produce 10 TWh in 2050, 5% of the state's generation.
- California's imports fall by 23 TWh (38%) over the study period.

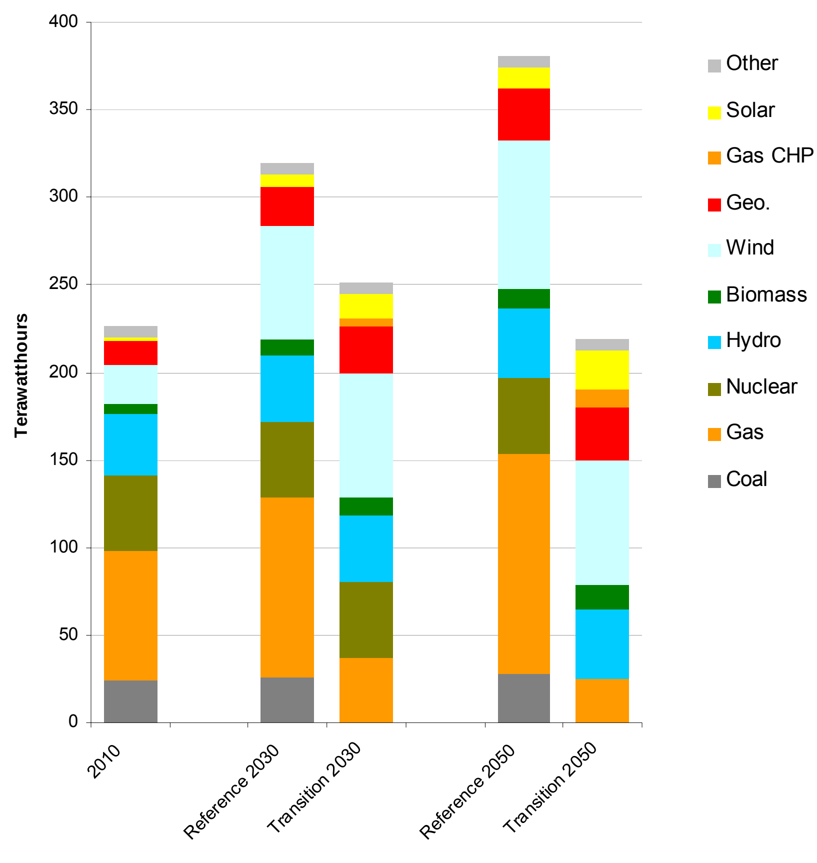

Figure 16. California in the Reference and Transition Cases

Table 16 shows the air impacts of the Reference and Transition Cases in the California. The figures shown are annual totals for 2010 and 2050. Electric sector emissions of CO_2 rise in the Reference Case and fall in the Transition Scenario. Cumulative CO_2 reductions from the Transition Scenario relative to the Reference Case total nearly 1.7 billion tons by 2050.

Emissions of NO_X fall in the Reference Case, as NEMS simulates implementation of new air regulations, but they fall much more in the Transition Scenario due to the phase-out of coal. Emissions of SO_2 rise in the reference case and fall in the Transition Scenario by 97%. Emissions of mercury are reduced by 80% in the Reference Case and by 100% in the Transition Scenario.

Table 16. Air Impacts in California

Case	2010	2050	% Change
CO_2 Reference (000 tons)	60,000	80,000	33%
CO_2 Transition (000 tons)	60,000	13,000	-78%
SO_2 Reference (000 tons)	19	20	5%
SO_2 Transition (000 tons)	19	1	-97%
NO_X Reference (000 tons)	77	90	12%
NO_X Transition (000 tons)	77	20	-74%
Mercury Reference (tons)	0.2	0	-80%
Mercury Transition (tons)	0.2	0	-100%

5. Conclusions

We draw the following conclusions from this work.

- By the middle of this century, the U.S. could replace coal-fired electricity generation with energy efficiency and renewable energy, and we could reduce our use of nuclear power. Near-term costs would be modest, and long term savings would accrue.
- A concerted, nation-wide effort to use electricity more efficiently would have to be a part of this strategy. A scenario in which the entire country achieved long-term energy savings similar to the most aggressive states and utilities today would be needed to make the scenario envisioned here possible.
- In terms of meeting peak loads, the current surplus of gas-fired capacity coupled with aggressive efficiency programs would provide ample room to add variable generation like wind and solar. Large amounts of new gas-fired capacity would not need to be added to "firm up" wind generation.
- The regional fuel mixes in the Transition Scenario are likely to allow system operators to incorporate the levels of wind generation envisioned here. Removing the most inflexible generation from regional power systems – coal and nuclear units – would make these systems much more flexible. The current trend toward demand response and larger balancing areas will add additional flexibility, as will the transmission investments we include in the Transition Scenario. (To be conservative, we have included wind integration costs throughout the study period.)
- Transmission investment would be needed to distribute wind energy around the Midwest and from the South Central region to the Southeast. We have estimated the cost of that transmission and included it in this analysis. Much less new transmission would be needed than envisioned in studies that do not include aggressive energy efficiency efforts. With efficiency and the development of in-region renewable resources, the Northeast would not need to import any electricity and California could import much less.
- Retiring roughly 85,000 MW of coal-fired capacity in the 2010 to 2020 period would save tens of billions in new emission controls, as plants facing large emission control investments would be targeted for retirement in this period.

This is a high-level study, and working out the details of a transition like the one envisioned here would be challenging. However it would certainly be no more challenging than working out the details of a carbon cap and trade program, a program to retrofit the nation's coal plants with new emission controls and a new generation of nuclear power plants. Moreover, energy efficient and renewable technologies are already in widespread use in our power sector. Carbon capture and sequestration remains speculative and no "new generation" nuclear plant has yet been completed.

The decisions we make now about how to remake our electric power industry will affect the lives of generations to come. We hope that this study contributes to a careful comparison of the options.

Appendix A: Methodology

This study investigates how a national strategy to phase out coal and nuclear energy might look. The focus is on what resources would be likely to replace coal-fired and nuclear generation and what this resource mix would cost relative to a "business as usual" energy future. The study is essentially national in scale, however we have ensured that the results are reasonable at the regional level, given the amount of coal and nuclear generation and the renewable resource base in each region and current interchange limits between regions.

Our method is essentially a spreadsheet-based analysis of regional energy balances. We began with data from the 2010 Annual Energy Outlook (AEO), released by the Energy Information Administration (EIA) in December 2009. Each year EIA uses the National Energy Modeling System (NEMS) to model a "Reference Case" energy scenario. EIA then analyzes various policy proposals by modeling the policy and comparing the results to the Reference Case. The AEO 2010 simulates U.S. energy production and use through 2035.

The electricity module of the NEMS model simulates the U.S. power sector in 13 regions. Electricity demand data for the entire study period are loaded into the model for each region. The model then adds generating capacity as needed to meet loads, and it balances energy production and demand in each region. The model includes general information about the U.S. transmission grid, and it allows for interregional power transfers within the limits of the transmission interfaces. Data are also loaded into the model on power plant costs—including both operating costs and the capital costs of new plants. Dispatch in each region is approximated based on unit operating costs, and capacity additions are based largely on the all-in costs of new plants.

For this study, we loaded the following data from AEO 2010 into a spreadsheet:

- Electricity use (TWh) by region,
- 2010 peak demand (GW) by region,
- Generating capacity (GW) by region and plant type,
- Generation (TWh) by fuel, and
- Emissions of CO_2, NO_x, SO_2, and mercury by region.

These data were loaded for each NEMS region and for each year 2007 through 2035. To simplify the project, we consolidated the 13 electricity regions in NEMS into eight. Figure 17 shows the regions in the NEMS electricity module.

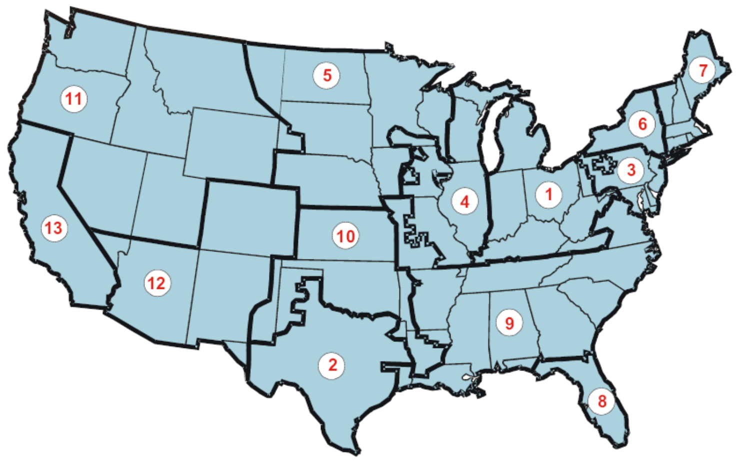

Figure 17. The Regions in the NEMS Electricity Market Module

Because the timeframe of our study extends beyond that of the AEO, we extrapolated the AEO data from 2035 through 2050. We did this by growing electricity demand, generation by fuel, and capacity additions by plant type using the average AEO growth between 2012 and 2035. These extrapolated data from AEO 2010 served as our Reference Case.

Next, we developed cost and performance assumptions for each resource type. We did this based on an extensive review of the current literature and on data that Synapse Energy Economics maintain. We used the AOE 2010 costs for very few technologies, primarily because these data do not appear to account for recent escalations in construction and materials costs. Many data sources, including cost numbers from actual projects, suggest that costs for many technologies are significantly higher than assumed for the AEO 2010. Thus, while capacity additions and energy generation in our Reference Case are the same as AEO 2010 through 2035, costs are not.

We developed the Transition Scenario in an iterative way. First, electricity loads were reduced from the AOE 2010 loads to simulate a concerted, national effort to become more energy efficient. Second, coal-retirement and renewable energy development scenarios were sketched out for each region based renewable technology costs data and each region's resources. Coal-fired capacity was retired at a rate that would not result in unrealistic development scenarios or costs. After rough scenarios were sketched out, the costs of new technologies over the study period were refined, based on the amount of capacity added nationwide. In the case of immature technologies, where much more capacity is added in the Transition Scenario than the Reference Case, costs fall faster in the Transition Scenario than the Reference Case. After adjusting costs, we revisited the capacity retirement and addition decisions, and so on.

The Transition Scenario is not optimized to meet any particular constraint. Other Scenarios could be developed with lower total costs, for example, or lower total CO_2 emissions. Additional work with optimization tools could no doubt improve on this scenario.

Costs are analyzed over the study period in constant 2009 dollars. We address the total direct costs of generation to society. This means that, first, we do not include the effects of subsidies and tax incentives in the costs of generating technologies. Second, it means that we have not included externalized costs, such as the health effects of pollution from power generation, the environmental impacts of coal mining. Externalized costs are important, but other studies address them better than we could within this scope of work.

A. Meeting Peak Loads

The U.S. is currently in a state of capacity surplus, largely due to the gas-fired capacity additions of the 1990s and 2000s and the current recession. Reducing energy use with aggressive efficiency efforts now would extend and increase this surplus. Thus, we would expect reserve margins to be maintained easily in the Transition Scenario, and the results of this analysis support this expectation.

We first estimated the effect on peak load of a MWh saved by a typical suite of efficiency programs. Most efficiency program reviews address the issue of peak load reductions. We assessed more than a dozen such reviews and took the average figure for peak load reductions from those reports. The result was a reduction of 0.13 kW per MWh saved. Using this assumption and the 2010 regional peak loads in the AEO data, we then estimated the peak load in each region and year in the Transition Scenario.

Next, we derated all wind and solar capacity (both preexisting and new) to account for the variability of these resources. We multiplied wind capacity by 15% and used regional factors to derate the solar capacity, based on an NREL study of PV energy's coincidence with peak loads in different regions (Perez 2006). We then compared derated capacity to estimated peak loads as in a traditional reserve margin analysis. Table 17 shows the 2010 margins calculated using the AEO 2010 data and the estimated margins for 2020 and 2030.[8]

Table 17. Estimated Reserve Margins Early in the Study Period

	2010	2020	2030
Northeast	33%	36%	50%
Southeast	45%	44%	63%
S. Central	46%	31%	41%
W. Midwest	43%	34%	35%
E. Midwest	25%	25%	49%
Northwest	58%	53%	78%
Southwest	51%	55%	74%
California	30%	31%	37%

Two points are worthy of note regarding this capacity check. First, a true reserve margin analysis takes into account operating limitations on many types of generators – not just wind and solar – and it focuses on much smaller energy balancing areas than we have

[8] Note that this is a rough check of capacity adequacy, not a rigorous reserve margin analysis. A true reserve margin analysis would need to consider operating limitations on many types of generators—not just wind and solar—and it would focus on a much smaller control area than the regions addressed here.

addressed here. Thus, our analysis should be construed as a rough check of capacity sufficiency and not a rigorous calculation of reserve margins. However, this check underscores the fact that today's considerable capacity surplus, coupled with aggressive energy efficiency, would provide ample room to add variable resources to the U.S. generating mix over the coming decades.

Second, because our method is primarily one of energy balancing, we have not carefully retired capacity to maintain efficient reserve margins. Thus, in some regions and years the margins in the Transition Scenario are much higher than historical reserve margins. If we had retired capacity throughout the study period to maintain more efficient reserve margins, the cost of the Transition Scenario would be lower, as the fixed operating costs of the retired units would be avoided.

B. Transmission

The NEMS model does not simulate the nation's transmission grid in great detail. The model includes exogenous transfer limits between regions and simulates economic power transfers within those limits. It does not recognize transmission constraints within regions or simulate power flows within regions. To approximate the cost of *intra-regional* transmission system upgrades, NEMS applies regional factors to peak loads. That is, EIA has developed assumptions for each region about the transmission system investment necessitated by each GW of growth in peak demand. These factors ($/GW) are then multiplied by regional loads each year to determine annual incremental costs. The model does not allow for increases in *inter-regional* transfer capabilities, so it includes no cost for such investments.

Using the load-based factors in from NEMS, we calculate roughly $8 billion in intra-regional transmission upgrades by 2050. In the Transition Scenario, loads fall rather than grow, so transmission investment would not be needed simply to move more energy, as in the Reference Case. However, intra-regional investment would be needed to bolster transmission that knits together the grid to allowing variable output resources to reach all parts of a given regional grid. We make the simplifying assumption that this would cost roughly the same as the intra-regional transmission investment estimated in AEO 2010. Thus, these costs are included in both scenarios.

In the Transition Scenario, the transmission flows in the west do not rise significantly, and we assume that the transmission costs there would be similar in both scenarios. In the Eastern Interconnection (including ERCOT), however, the Transition Scenario would require investment in new, inter-regional transmission capacity. To estimate this cost, we estimated transmission flow allocation from one region to another in each case and used this to determine estimated interregional flows (annual TWh) to preserve the energy balances. We then compared the Transition Scenario flows to the Reference Case flows to determine the incremental energy flow requirement (annual TWh between regions) in the Transition Scenario. Based on these increments and estimates for the costs of new EHV transmission, we estimate total inter-regional transmission costs for the Transition Scenario to be in the range of $20 to $60 billion by 2050. We include the midpoint of this range in the costs of the Transition Scenario. (Annualizing these costs with the same real, levelized fixed charge rate used for the supply-side technologies, yields $3.1 billion per year by 2050.)

C. Estimating Avoided Emission Control Investments

Three federal regulations have been promulgated that will require new emission controls at existing coal-fired power plants: the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR), and the Clean Air Mercury Rule (CAMR). CAIR and CAVR address emissions of SO_2 and NO_x. For both of these rules, states will be required to develop SO_2 and NO_x control plans for power plants based on a the "best available retrofit technology." Since the standard for controls is the same for both rules, compliance with CAIR is expected to satisfy CAVR for units in the east. CAMR will require best available retrofit technology to reduce mercury emissions from units nationwide.

Units that install controls pursuant to these rules will likely install flue gas desulferizaton (FGD) systems for SO_2 and selective catalytic reduction (SCR) for NO_x. At this point, it is not clear which affected units will install controls. EPA's initial CAIR rule included an allowance trading program. However, a district court vacated the rule, and EPA's revised rule is likely to allow much more limited allowance trading. This would force more units to install controls. In our Transition Scenario we retire 85,000 MW of coal-fired capacity between 2010 and 2020.

In a coal-phase out scenario, the units facing high emission control costs would be among the first targeted for retirement. Therefore, we assume that emission controls would be avoided at a large percentage of the units we retire between 2010 and 2020. We assume that 80% of the units retired in this period would have installed an FGD system and that 80% of them would have installed SCR.

We base the cost of these controls primarily on recent cost-recovery proposals from utilities. These recent proposals have been significantly higher than typical recent assumptions. For example, the AEO 2009 inputs for the cost of FGD systems range from 200 to 310 $/kW, with costs higher for smaller units. Three recent utility proposals are all over 600 $/kW[9]. The AEO 2009 inputs for SCR costs range from 105 to 130 $/kW, and one recent proposal put this cost in the range of 400 $/kW. Based on these numbers, we assume FGD systems cost $500 $/kW and SCR systems cost 350 $/kW.

The cost of mercury controls depends on whether the unit already has a particulate control device. For units with these controls the incremental costs of mercury controls are very small – in the range of 5 $/kW. For units without particulate controls, costs are in the range of 70 $/kW. We assume that half of the units subject to CAMR have particulate controls.

[9] These cost for FGD are from utility commission proceedings regarding the Boardman plant in Oregon, the White Bluff plant in Arkansas and the Columbia plant in Wisconsin. The cost sited for SCR is from the Boardman plant.

These assumptions yield a total cost avoided of $58 billion. We estimate annual avoided costs using the same 7.8% fixed charge rate used elsewhere in this study. Note that this is a very rough estimate, subject to a number of uncertainties.

6. Appendix B: Cost and Performance Assumptions

In developing cost and performance assumptions for the Reference Case and the Transition Scenario, we have been guided by a number of recent studies. This section presents our assumptions about each resource and conversion technology and the information on which we base those assumptions.

Because our study takes a societal perspective, we do not include the effects of subsidies and tax incentives on technologies. We also use a real, levelized fixed charge rate of 7.8% to calculate levelized costs of energy. This is consistent with: a 6.5% cost of debt; an 8.0% cost of equity; a 50/50 debt/equity ratio; and a property tax rate of 2%. Note that because this is a real (inflation adjusted) fixed charge rate, it is lower than many fixed charge rates in the literature. However, because this study uses constant dollars, it is important to use a real fixed charge rate. Also note that all costs quoted from sources have been converted into 2009 dollars, except where otherwise indicated.

Experience across many technologies has shown that the costs of immature technologies fall rapidly once global demand reaches a level that allows for economies of scale, the standardization of manufacturing, and competition among a number of suppliers. The policy environment that we envision would certainly push several renewable technologies into maturity more quickly than would business-as-usual energy policy. Therefore, the cost of less mature technologies falls faster in the Transition Scenario than in the Reference Case. However, we have also been conservative, wanting to ensure that each technology follows a reasonable cost trajectory given its current state of maturity and the amount of capacity added in each scenario. Thus, the costs we assume for 2010 are generally not the lowest in the literature, and our forecasted cost reductions for the Transition Scenario are generally not the most aggressive in the literature.

One factor we have been careful to capture in our assumptions is the increased cost of construction and many construction inputs over the last decade. A number of articles and cost indices document these cost increases (see, for example, Wald 2007). The Union of Concerned Scientists (UCS) assessed the increases thoroughly for its Climate 2030 study, reviewing actual project data and several construction cost indices. They found real cost increases of “50 to 70 percent since 2000, with most of them occurring after 2004” (see UCS 2009, Appendix D). These increases have affected nearly all types of new power plants.

There is some evidence that construction and materials costs are beginning to fall, perhaps as a result of the global recession. Thus, our 2010 cost assumptions reflect higher current construction and materials costs, and we assume a trend back to historical levels by the midpoint of this decade. For the capital-intensive technologies with long construction periods (nuclear, coal, geothermal and biomass), we have raised installed costs in 2010 by roughly 20% as it appears that most of our sources have captured some, but not all of the construction cost increases. For less capital intensive technologies, like combined-cycle combustion turbines, 2010 costs are 10% above historical levels. In both cases, capital costs return to historical levels during the next decade.

Beyond falling near-term construction costs, our costs trajectories are largely a function of capacity additions. For less mature technologies, where much more capacity is added in the Transition Scenario than the Reference Case, costs fall faster in the Transition Scenario than the Reference Case. This is consistent with the way that cost trajectories are determined within NEMS, however we do not use the function NEMS uses to determine future costs. Our future costs are based on our review of the literature for each technology. In this Section we show how costs fall with capacity additions for each new technology.

A. Energy Efficiency

Current Efficiency Efforts

In the U.S., energy efficiency has been promoted by utility programs, state building codes and appliance standards. State building codes and federal appliance standards have played an important role in promoting efficiency; however, utility energy efficiency programs have been the most aggressive policy driver. Utility programs have encouraged efficiency through a range of measures, including free energy audits, rebates for efficiency measures, and education of customers.

Currently, utility programs are saving about 10,000 GWh annually; equivalent to about 0.3% of national retail electricity sales.[10] However, leading utilities in states such as California, Massachusetts, and Vermont are achieving much higher rates of energy savings. For example, Efficiency Vermont, a non-utility provider of energy efficiency, achieved annual incremental savings of 2.5% in 2008, which was higher than the "achievable potential" (2.2%) identified by a 2007 study of the state (MA EEAC 2009). Table 18 shows the recent efficiency savings levels for selected utility energy efficiency programs.

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[10] This estimate is based on our review of (1) U.S. EIA File 861 file on utility demand side management programs in 2007l (2) various state specific energy savings reports and (3) data provided directly by state agencies who oversea utility programs.

Table 18. Efficiency Savings for Selected Entities' Efficiency Programs

Entity	Annual Savings (%)	Year(s)	Source
Interstate Power & Light (MN)	2.6	2006	Garvey, E. 2007. "Minnesota's Demand Efficiency Program."
Efficiency Vermont (VT)	2.5	2008	Efficiency Vermont 2009. 2008 Highlights
Massachusetts Electric Co.(MA)	2.0	2006	EIA 861
Pacific Gas & Electric (CA)	1.9	2008	CPUC 2009. Energy Efficiency Verification Reports issued on February 5, 2009 and October 15, 2009
Minnesota Power (MN)	1.9	2005	Garvey, E. 2007
Puget Sound Energy (WA)	1.4	2007	Northwest Power and Conservation Council
Connecticut IOUs (CT)	1.3	2006	CT Energy Conservation Management Board (ECMB). 2007
Pacific Corp (ID & WA)	1.3	2007	Northwest Power and Conservation Council
Energy Trust of Oregon (OR)	1.3	2005	Northwest Power and Conservation Council
Southern California Edison (CA)	1.2	2008	CPUC 2009
Avista Corp (ID, WA, MT)	1.1	2005	Northwest Power and Conservation Council
Idaho Power Co (ID)	1.1	2007	Northwest Power and Conservation Council
San Diego Gas & Electric (CA)	1.1	2008	CPUC 2009
PUD No 1 of Snohomish (WA)	1.0	2007	Northwest Power and Conservation Council
Otter Tail (MN)	0.9	2005	Garvey, E. 2007. "Minnesota's Demand Efficiency Program."
Seattle City Light (WA)	0.9	2007	Northwest Power and Conservation Council
MidAmerican (IA)	0.9	2006	Iowa Utilities Board 2009

In response to higher energy costs, fossil fuel dependence and climate change, states are generally requiring utilities to capture greater savings than they have in the past; states are also expanding efficiency program requirements to include non-investor owned utilities, such as municipal utilities and co-operatives. At least 11 states have established goals of annual energy savings at or above 2% of retail sales. Table 19 summarizes the current efficiency goals of various states.

Table 19. Assessment of all available cost effective electric and gas savings

State Energy Efficiency Resource Standards Activity				
State	**Date Established**	**Goal**	**Target End Date**	**Implied Annual % savings (% of total forecast load)**
Texas	2007	20% of load growth	2010	0.50%
Vermont	2008	2.0% per year (contract goals)	2011	2.00%
California	2004	EE is first resource to meet future electric needs	2013	2.0% +
Hawaii	2004	.4% - .6% per year	2020	0.50%
Pennsylvania	2008	3.0% of 2009-2010 load	2013	0.60%
Connecticut	2007	All Achievable Cost Effective	2018	2.0% +
Nevada	2005	0.6% of 2006 annually4	n/a	0.60%
Washington	2006	All Achievable Cost Effective	2025	2.0% +
Colorado	2007	1.0% per year	2020	1.00%
Minnesota (elec & gas)	2007	1.5% per year	2010	1.50%
Virginia	2007	10% of 2006 load	2022	2.20%
Illinois	2007	2.0% per year	2015	2.00%
North Carolina	2007	5% of load	2018	0.40%
New York (electric)	2008	10.5% of 2015 load	2015	1.50%
New York (gas)	2009	15% of 2020 load	2020	1.50%
New Mexico	2009	All achievable cost-effective, minimum 10% of 2005 load	2020	1.0% +
Maryland	2008	15% of 2007 per capita load	2015	3.30%
Ohio	2008	2.0% per year	2019	2.00%
Michigan (electric)	2008	1.0% per year	2012	1.00%
Michigan (gas)	2008	0.75% per year	2012	0.80%
Iowa (electric)	2009	1.5% per year	2010	1.50%
Iowa (gas)	2009	0.85% per year	2013	0.30%
Massachusetts	2008	All Achievable Cost Effective		2.0% +
New Jersey (elec & gas)	2008	20% of 2020 load	2020	≤2.0%
Rhode Island	2008	All Achievable Cost Effective		2.0% +

Source: MA EEAC 2009

Efficiency Potential Studies

A number of studies have assessed the potential for efficiency in various states and the nation. These studies typically estimate “technical,” “economic” and “achievable” potentials. Technical potential is defined as the amount of energy savings from all energy efficiency measures that are considered technically feasible from an engineering perspective, regardless of cost or practicality. Economic potential is a subset of technical potential including only cost-effective measures whose energy savings benefits outweigh the cost of power supply. Achievable potential further screen the economic potential based on practical policy, infrastructure, funding and consumer response limitations. It is essentially an estimate of the impacts that *typical efficiency policies and programs* can have on influencing customer energy use through adoption and implementation of energy-efficient technologies. Understanding these distinctions explains how Efficiency Vermont could capture more savings than an estimate of the achievable potential.

The Energy Center of Wisconsin (ECW and ACEEE 2009) recently conducted a comprehensive review of a number of efficiency potential studies and analyzed their implications for the Midwest. Given the broad scope of this study, its conclusions on efficiency potential are important. The study finds an average annual achievable savings of about 1.4% per year (Figure 18 below).

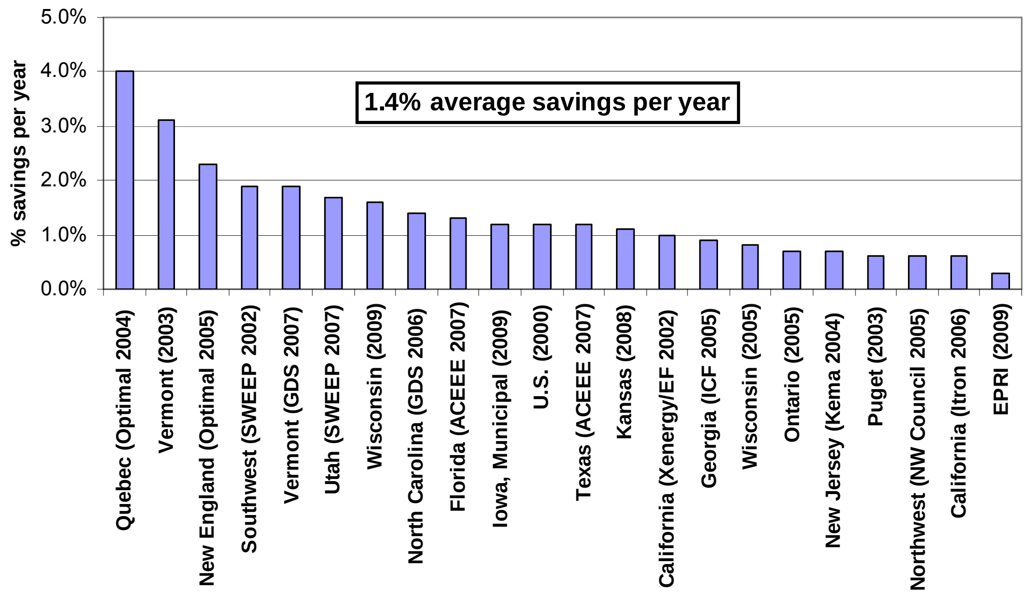

Figure 18. Summary of Achievable Potential Studies (% savings per year)
Source: ECW and ACEEE 2009

The Georgia Institute of Technology also recently conducted a meta-analysis of efficiency potential, focusing on efficiency potential by sector. This study found very similar levels of potential across the three sectors. Potentials tend to be the highest in the residential sectors and lowest in the industrial, as seen in Figure 19. The technical potential ranges from 3.0% of annual energy use in the residential sector to 2.3% in the industrial (Jess Chandler 2010). The economic potential ranges from 2.0% in the residential sector to 1.5% in the industrial.

While the Wisconsin meta-study found an average savings potential of 1.4% across these studies, they also state that conservatisms in the studies are like to be causing a systematic understatement of efficiency potential. The Wisconsin authors believe that the potential in this region is probably closer to a 2% annual reduction in electricity use (ECW and ACEEE 2009). We share this view. Common limitations and conservatisms in efficiency potential studies include the following.

- The avoided energy costs in the studies are lower than either present or projected generation costs.
- Key assumptions tend to be conservative – particularly customer participation realization rates).
- The studies emphasize incremental changes and improvements, excluding greater savings opportunities through the integrated effects of comprehensive packages.
- They do not account for emerging technologies, continued improvements of technologies and cost reductions of such technologies over time.

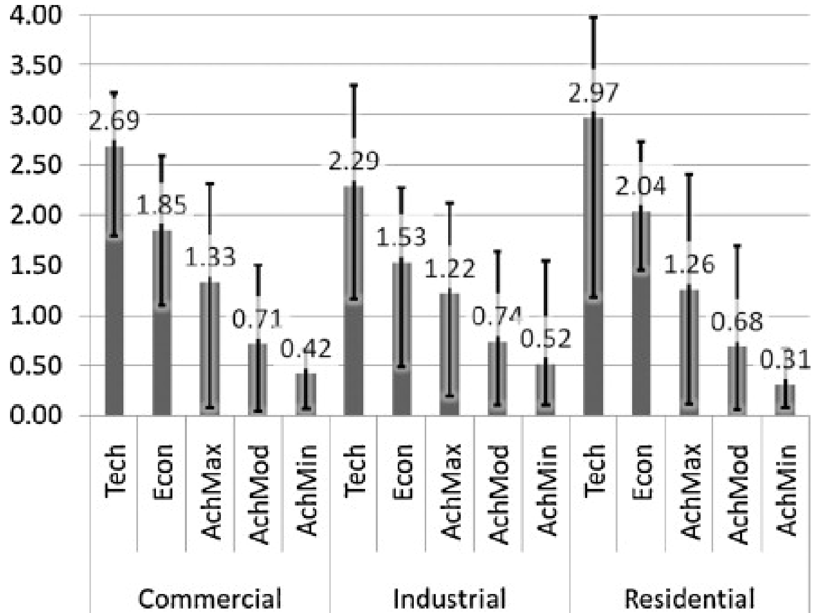

Figure 19. Average Electric Efficiency Potential per year by Sector
Note: Error bars indicate the range from minimum to maximum.

Thus we agree with the authors of the Wisconsin study that 2% is a more appropriate estimate of the potential. However, studies aside, the most important basis for this assumption is that some utility efficiency programs are *already* achieving annual savings of 2% (see Table 18), *and these numbers reflect utility programs only*. They do not include the additional savings that accrue from updated building codes and appliance standards.

Thus, for the Transition Scenario, electricity use is reduced from Reference Case levels in 2011 by 0.2%, and the reduction from the Reference Case grows to 2.0% annually in 2021 and remains there for the duration of the study.

The Cost of Energy Efficiency

Energy efficiency is consistently one of the most cost-effective electricity resources available. For example, efficiency programs were recently incorporated into electric capacity markets in New England, and these resources, along with demand response programs, have helped to drive down the costs of capacity in the region (ISO-NE 2008).

The cost of saved energy (CSE) from utility energy efficiency programs is currently well below the all-in cost of new conventional supply-side resources. New supply-side resources cost between 70 and 150 $/MWh (7 to 15 cents per kWh). Figure 20 compares a number of efficiency program cost estimates. The average is 2.4 cents/kWh, and the median is 3 cents/kWh (SEE 2008). In 2009, ACEEE reviewed the cost of saved energy in utility and third party efficiency programs from fourteen leading states and concluded that the average utility costs ranged from 1.5 to 3.4 cents per kWh, an average value of 2.5 cents/kWh (ACEEE 2009).[11] The study also found that on average, utilities bear about 60% of the energy efficiency cost and customers about 40%. This implies that the total cost of energy efficiency measures, including participant's costs, is about 4 cents/kWh.

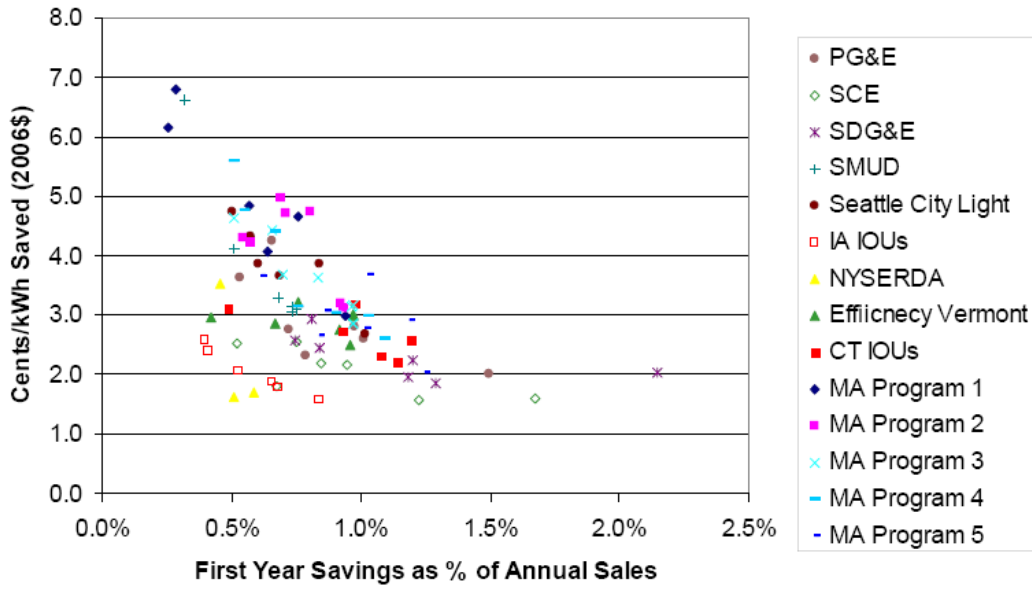

Figure 20. Cost of Saved Energy (CSE) by Utility Efficiency Programs
Source: SEE 2008

Additionally, there is increasing evidence of economies of scale on the cost of energy efficiency. As presented in Figure 20, we evaluated historical trends in the cost of saved energy (CSE) for utility and third party energy efficiency programs and found that the CSE decreased when program scale and impact were expanded (SEE 2008).

Further, savings from appliance standards tend to be cheaper than from utility programs. Studies of the cost of building energy codes and appliance standards suggest that the cost of appliance standards is about 1 cent/kWh saved and that the cost of building codes range from 3 cents to 4.7 cents/kWh (WGA 2006).

For the purpose of our study, we assume an average cost of 4.5 cents/kWh for energy efficiency savings. This represents an average cost for utility programs, state building energy codes, advanced building energy programs, and appliance standards.[12] This estimate includes the cost borne by program administrators and by participants in those programs. We assume the cost remains at the same level in real terms through 2050.

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[11] The utility cost of saved energy through energy efficiency programs represents the costs incurred by the utility or efficiency program administrator. This metric typically includes the costs associated with program administration, marketing, measurement and evaluation, and participant incentives and rebates, but it excludes participants' costs – the cost participants pay minus the amount of utility incentives. Total costs capture both cost categories.

[12] Levelized cost of energy efficiency is the annualized cost of efficiency assuming a certain discount rate and an efficiency measure life value. This is equivalent to borrowing money from a bank at a certain loan rate (e.g., 5%) for a certain period of time (e.g., 15 years).

Energy Efficient Technologies

The efficient technologies replacing older equipment today are too numerous to list here, but below we provide examples of the kind of technologies that would be the basis of a long-term, national effort to reduce electricity use.

- Compact fluorescent lights (CFLs) use 75% less energy than incandescent bulbs and last 5 to 10 times longer (Arnold and Mellinger 2009; US EPA Energy Star website). CFLs have been promoted by utility efficiency programs for the past decade, but CFL market saturation in leading states is still only about 10 to 20% (NMR 2010). Emerging LED lighting uses even less energy than CFLs, and lamps lasts longer than CFLs (Efficiency Vermont 2010). LEDs are likely to provide the next generation of lighting after CFLs, and to result in falling energy use for lighting for several decades to come. A recent energy efficiency potential study by the National Academy of Science estimated that replacing all lamps with CFLs would save lighting energy by 32%. Eventually replacing all lamps with LEDs would save lighting energy use by nearly 70% relative to the current levels (NAS et al. 2009).
- Similarly, LED televisions are already on the market and consume 40% less energy than comparable LCD models (NWPCC 2010). This represents considerable future savings, as plasma and LCD sets are replaced.
- Electricity use in heating, ventilation, and air conditioning (HVAC) equipment can still be reduced considerably by simply by applying inverter technologies that optimize HVAC output (Daikin 2010). Most residential and commercial HVAC equipment in the U.S. operates in a binary (on or off) mode, but variable speed inverter technologies allow HVAC units to change their output in response to load. These technologies have been used in Europe and Japan for more than two decades. They are now used in virtually all residential HVAC equipment in Japan, and they are rapidly being adopted in China.
- Heat pump technology can now be used for cooling and heating buildings in nearly all climates (Daikin 2010; Mitsubishi Electric n.d.).[13] The Coefficient of Performance (COP) of today's heat pumps can reach 4, meaning that the energy output is quadruple the energy input (U.S. DOE EERE n.d.a). A heat pump's efficiency can exceed 100%, because it uses electricity only for operating pumps to move heat from outdoor to indoor spaces for heating and vice versa for cooling.
- The potential for reduced energy use from washers and dryers also remains vast. New models using a heat pump and tilted cylinder consume about 0.72 kWh per load compared to 1.4 kWh per load for a current Energy Star unit in the U.S. (JASE World n.d; Las Vegas Sun 2009; US EPA. n.d.).

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[13] According to Mitsubishi Electric, the Hyper-heating Inverter Y-Series provides 100% of rated heating capacity at 5°F and 90% at -4°F outdoor ambient, while typical heat pumps operate at 60% capacity at 5°F.

- Water heating accounts for about 6% of total commercial energy use and 12% of residential energy use (US DOE EERE 2009). Tankless hot water heaters can provide 45% to 60% energy savings relative to electric water heaters. Hot water heaters using heat pumps can cut energy use by 50% to 65%. Solar hot water heaters can save energy by about 90%, however a backup heater is required when sunlight is not available (US EPA n.d.).
- A 5,300 square foot house called the Ultimate Family House in Las Vegas Nevada incorporates a number of advanced building design components that reduce heat gain during the summer. The house uses 64% less electricity for cooling and 62% less electricity overall compared to a home built to code (NREL 2003). The site also has an 8.6 kW PV system.
- An experimental super-energy-efficient photovoltaic residence in Lakeland, Florida demonstrated a 70% to 84% reduction in cooling loads. When the PV electric generation is included during the peak period, the home net demand was only 199 W – a 93% reduction in electricity requirements (FSEC n.d.).
- Durant Road Middle School in Raleigh NC incorporated many passive solar and cooling features including overhangs, a radiant barrier roof blocking over 90% of the radiant heat, lighting controls that adjust conventional fluorescent lighting as needed, low-e glazing on windows, ventilation system for fresh-air circulation, and a downsized electric chiller for cooling (US DOE EERE n.d.b). The school consumes about 70% less electricity than the average school built during the same period.[14]
- A 1,232 square foot new construction project in Townsend, MA, participated in the Zero Energy Challenge program and has achieved net-zero energy status quite cost-effectively (MA DOER n.d.; Zero Energy Challenge n.d.). Relative to a house with code compliance, the house achieved a 70% reduction in space heating, a 60% reduction in cooling, a 90% reduction in water heating, a 23% reduction in lighting and appliances (Zero Energy Challenge n.d.). With the addition of a PV system, the house is estimated to be a net-zero building.

B. Wind Energy

The wind power industry has experienced robust growth over the last decade. In 2009 alone, the U.S. saw the installation of almost 10 GW of new wind capacity, increasing its installed capacity by 39% and bringing total grid-connected capacity to 35 GW (GWEC 2010).

Average wind capacity factors range from about 25 to 40 percent, with the low end representing class 3 to 4 wind sites and the high end representing class 5 to 6 wind sites (RETI 2008). The economics of a site depend largely on wind class (with higher classes

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[14] In 2003, nationally schools consumed 27.9 kBtu/sf (or 8.1 kWh/sf) per year on average for cooling, lighting, and fans/pumps, according to US DOE EERE 2009. 2009 Building Energy Data Book, Table 3.1. In contrast, the Durant Road Middle School only consumes 8.4 kBtu/sf (or 2.5 kWh/sf) for the same end uses.

generally yielding better capacity factors and lower levelized costs), location on or off shore, and access to existing transmission. As compared to onshore wind, offshore wind projects are roughly twice the cost because of their high-cost foundations, but offshore sites generally have higher capacity factors, reduced wind variability, a better diurnal profile relative to load, and they are often closer to load. Wind turbine performance and reliability have improved significantly over the last decade: average capacity factors for U.S. wind projects have increased from about 24% in 1999 to over 32% in 2005 (RETI 2008).

The Wind Potential

Figure 21 shows U.S. wind power potential, including Alaska, Hawaii, and offshore resources at 50 m height.

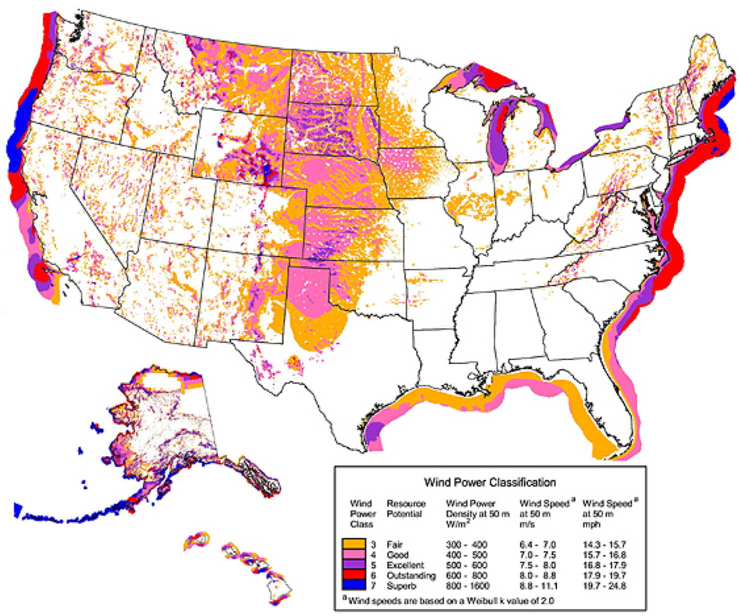

Figure 21. U.S. wind resources by class at 50 m height. *Source: DOE EERE 2010b.*

In 2010, NREL released an assessment of wind potential at 80 m height for land-based wind in the 48 contiguous states. Relative to the previous estimate at 50 m height (reflected in Figure 21 above), total estimated potential rose from roughly 10,800 TWh per year to 37,000 TWh, reflecting the fact that today's taller turbines can access stronger winds at 80 m and also more refined wind measurements (DOE 2010a; AWEA 2010). This is over nine times the country's current annual electricity use.

Generally, areas with annual average wind speeds of 6.5 meters per second or greater and turbine capacity factors of 30% or more are considered to have suitable wind resources for development (DOE 2010a). Based on the GIS data and NREL's standard assumptions about excluded areas and wind power density, AWEA 2010 estimates the total wind resource in the contiguous 48 states to be 7,834 GW of land-based potential, 1,261 GW of shallow offshore potential, and 3,177 GW of deep offshore potential. While much of this potential is in class 3 wind areas, there is still 2,700 GW of land based potential in wind power classes 4 through 7.

Wind Energy Costs

A team at Lawrence Berkeley Laboratories has mapped the installed costs of U.S. wind projects over time using data from 252 projects, as shown in Figure 22 (Wiser et. al. 2009). This figure shows that the lowest cost period was 2001 to 2003, with costs rising roughly 60% between then and 2008. The authors project 2009 costs in the range of 2,140 $/kW. They cite a weak U.S. dollar relative to the Euro as the major cause of this trend, as most turbine manufacturers are located in Europe. But increases in the cost of steel and other materials are also a factor. Based on these data, we assume 2010 installed costs of onshore wind power in the U.S. are 2,200 $/kW, or about 63% above their lows in 2001 to 2003. Note that we are not alone in assuming rising capital costs for wind projects. UCS 2009 assumes installed costs of roughly $2,450/kW for onshore wind in 2015, and RETI 2008 assumes costs between 1,919 and 2,424 $/kW.

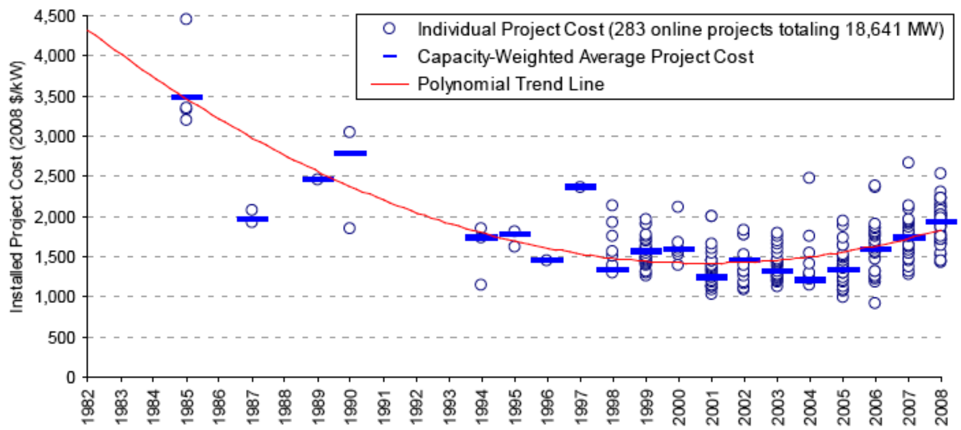

Figure 22. The Trend in Capital Costs for U.S. Wind Power. *Source: Wiser et. al. 2009.*

The most detailed analysis of U.S. wind cost and potential was performed for the DOE's 2008 study 20*% Wind Energy by 2030* and its predecessor, AWEA's 2007 report *20 Percent Wind Energy Penetration in the United States* (DOE EERE 2008 and AWEA 2007). Both reports include detailed supply curves for wind energy in each of nine U.S. regions. These supply curves are based on an analysis of site types in different regions of the country. Because of this rich regional detail, we use these supply curves in our analysis, however we adjust the cost of energy in the curves to account for the increased installed costs discussed above. AWEA 2007 uses total installed costs of 1,750 $/kW for onshore wind, and as noted, we adjust this to 2,200 $/kW. AWEA uses 2,490 $/MWh for offshore projects and we adjust this to 3,500 $/MWh.

Figure 23 shows the national wind supply curve, from AWEA 2007, developed using these costs. The report provides the same data divided into regional supply curves, and it also breaks these costs into capital costs, fixed and variable O&M, regional construction factors and regional transmission adders.[15] This detail allowed us to essentially update the regional supply curves using the higher installed costs discussed above.

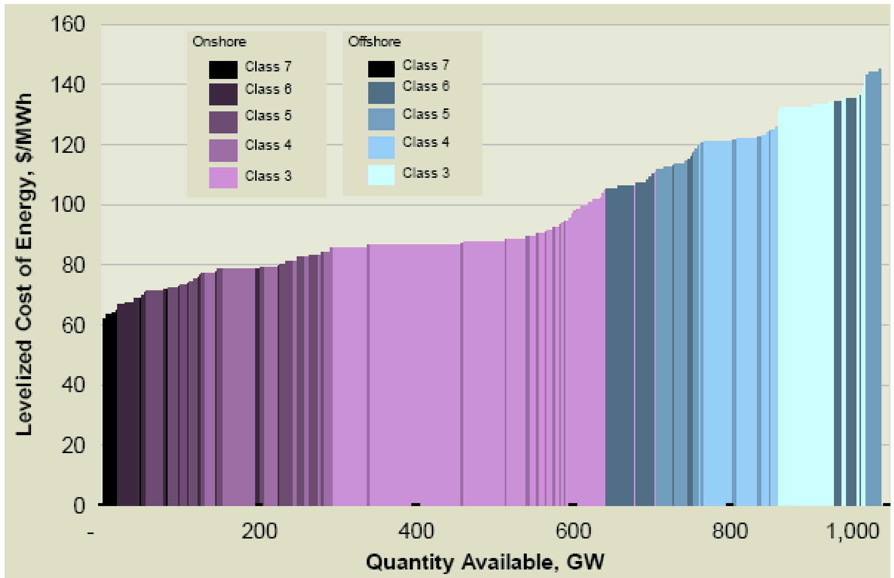

Figure 23. Wind Energy Supply Curve from AWEA 2007

The installed wind costs we use, developed by updating the regional supply curves from AWEA 2007, are shown in Table 1 in Section 2.

C. Photovoltaics

Today's PV technologies fall into two categories, crystalline silicon and thin-film, although research has recently focused on other materials. Crystalline silicon technology came first, and most PV cells in operation today use this technology. However, because demand for silicon is high for other manufacturing needs, much research has been focused on thin-film technologies that use a much thinner layer of active material mounted on a lower-cost base. Thin film technologies are already slightly cheaper than crystalline silicon in many applications, and that gap is projected to widen over time.

Crystalline silicone cells currently have conversion efficiencies in the range of 15 to 20%. These cells are typically grouped onto panels and mounted on rooftops or at ground level. Arrays can be fixed or mechanized to track the sun. Tracking arrays cost more but deliver more energy per day than similar fixed arrays. Conversion efficiencies for thin-film technologies are in the range of 5 to 10%. Thin-film PV cells can also be incorporated into building materials, and over the long term many low-cost applications are envisioned for new construction, such as PV-integrated roof and wall coverings.

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[15] The regional construction factor captures the differing costs of construction in different regions of the country. The regional construction factors increase installed costs by: 26% in the Northeast; 16% in the MidAtlantic; 12% in the Great Lakes and 6% in the Southeast. There are no construction factors for the other regions of the country.

The PV Potential

The total incident solar energy falling on the continental U.S. is about 50 trillion kWh/day (ASES 2007). Figure 24 from NREL shows the variation of this resource across the U.S.

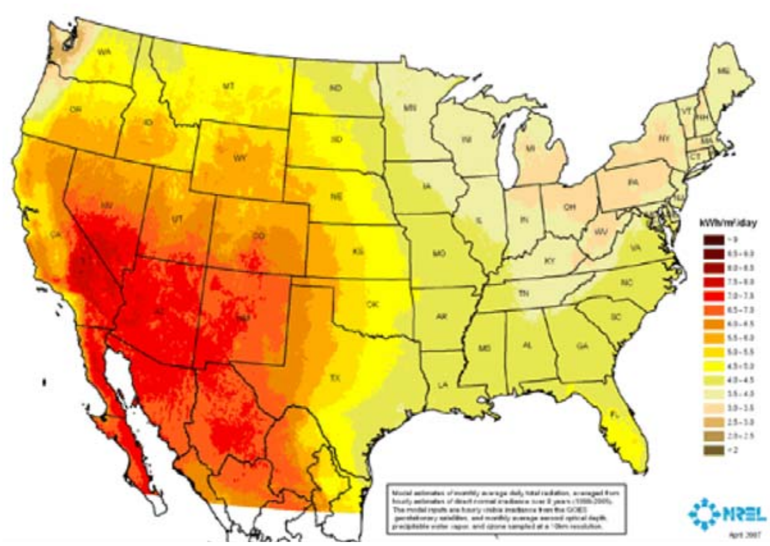

Figure 24. Annual Direct Normal Solar Radiation. 8 Year Mean Values (1998-2005) – SUNY 10km Satellite Model.

Not surprisingly, the Southwestern U.S. has the greatest solar resource base, and the Northeast has the smallest. To translate these insolation levels into an estimate of PV's technical potential, one must consider average PV system efficiencies and the available land and rooftop space. ASES 2007 estimates the current technical potential of PV at 600 to 1,000 GW of capacity. This translates into 900 to 1500 TWh per year of energy, assuming an average capacity factor of 17%. (For reference, 1500 TWh was about half the 2007 electricity use in the U.S.) A 2004 study by Navigant Consulting produced similar numbers, estimating the growth of the technical PV potential in the U.S. at 542 GW in 2003 and 1,038 GW in 2025 (Navigant 2004). The technical potential grows over time, because the amount of roofspace in the country increases and because PV systems will deliver more energy per unit area as they improve.

PV Costs

Current costs of PV systems are high relative to many other technologies. Wiser et. al. 2009 reviewed a database of 52,000 U.S. PV projects and calculated the average cost of systems installed in 2008 at 7.5 $/W, not including subsidies. This is a decrease of 0.3 $/W from 2007. Note that the costs of small, distributed PV projects (like residential rooftops) are significantly higher than those of larger "central" or "utility-scale" projects, and the average cost cited above is heavily weighted toward small projects.

AEO 2010 puts the current cost of utility scale projects at 6.2 $/W. Lazard 2008 estimates current crystalline silicon costs in the range of 5.5 to 6.0 $/W and thin-film costs in the range of 3.5 to 4.0 $/W, both for 10-MW scale projects. UCS 2009 estimates current costs of distributed projects at 8.0 $/W and central projects at 5.6 $/W. Navigant 2008 estimated 2008 costs at 7.1 $/W for distributed projects and 6.6 $/W for central projects. RETI 2009 puts current crystalline silicon costs at 7.0 $/W and thin film projects at 3.7 $/W. Based on these studies, we use 2010 installed costs of 7.1 $/W for distributed PV projects and $6.0 $/W for central projects.

PV costs have been falling steadily over the past decade, but not quickly. Figure 25, from Wiser et. al., 2009, shows the trend in average project costs from 1998 through 2008 – a reduction of 3.6% per year. Note in this chart that PV has not seen the same cost escalation in recent years as other technologies.

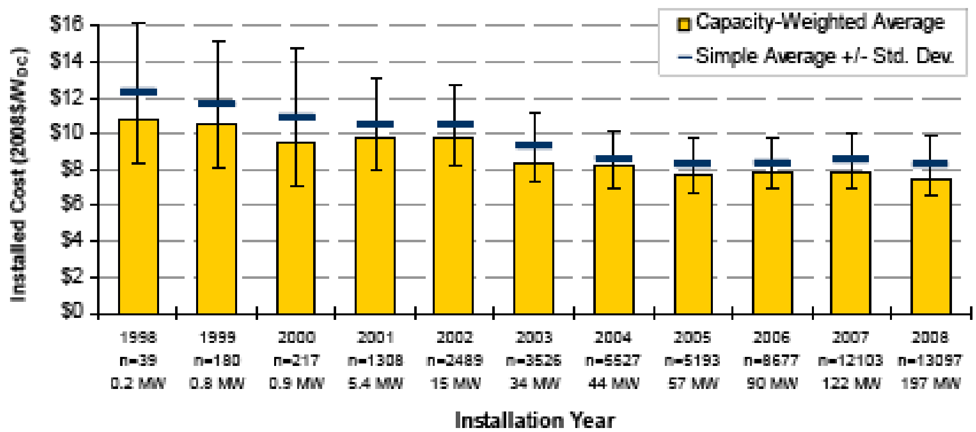

Figure 25. Average Installed Cost of PV Projects, 1998 – 2008. *Source: (Wiser, et. al., 2009).*

Many analysts are projecting much steeper cost reductions for PV in the coming decade, especially for thin-film modules. Globally, 5,948 MW of PV were installed in 2008, up from 2,826 in 2007 (Wiser et. al., 2009). Strong support for PV in both Germany and Spain were key drivers of this growth; in the U.S., 335 MW were installed in 2008. These levels of global demand are pushing the PV industry to new levels of manufacturing scale and sophistication.

The costs we use for current and future PV projects in the Reference and Transition Cases are shown in Figure 2 in Section 2.

D. Concentrating Solar Power

Concentrating solar power (CSP), also known as solar thermal power, uses the heat of the sun to generate electricity. CSP plants are utility-scale generators that use mirrors and lenses to concentrate the sun's energy to activate turbines, engines, and photovoltaic cells to produce electricity. Maximum power is generated by CSP plants in the afternoon hours, and this correlates well with peak electricity loads in hot climates. However, unlike PV systems, which can use diffuse sunlight, CSP systems require direct sunlight, known as "direct-normal solar radiation." This limits the geographic range of the CSP potential primarily to the Southwest, where the weather is consistently clear enough to provide sufficient direct radiation.

CSP includes technologies such as parabolic troughs, dish-Stirling engine systems, power towers, and concentrating photovoltaic systems (CPV). Parabolic troughs are the most advanced CSP technology, and they have been in operation in the United States since the 1980s. The troughs consist of long, curved mirrors that concentrate sunlight onto fluid-filled tubes, creating steam to move a power-generating turbine. Solar power tower systems include a field of flat mirrors that direct sunlight to a liquid filled-central receiver. Tower systems generally concentrate heat at higher temperatures than other CSP technologies, improving conversion efficiencies relative to troughs. Dish-Stirling engine systems are composed of mirrored dishes that track the sun and direct sunlight to a fluid, which powers a Stirling engine. In concentrating PV systems, lenses or mirrors concentrate sunlight onto PV cells. These systems use high-efficiency PV cells, which cost more, but the concentration of light deceases the cell area required.

As of August 2009, the United States operated 429 MW of CSP, making it the world leader in installed CSP capacity (EESI 2009).

The CSP Potential

The American Solar Energy Society (ASES) assessed the technical potential for solar CSP in the US. Using GIS data, ASES estimated the amount of land suitable for large-scale deployment of CSP systems in the southwestern United States. In making this estimate they excluded:

- land that had less than 6.75 kilowatt-hours per square meter per day of average annual direct-normal solar radiation,
- land that was incompatible with commercial development,
- land with slopes greater than 1%, and
- contiguous areas smaller than 10 square kilometers.

Given these exclusions, ASES estimated the potential for solar CSP generating capacity in the southwestern United States at nearly 7,000 GW (ASES 2007).

In addition to this assessment of technical potential, several studies have forecasted CSP development scenarios, assuming continued federal and state support for the technology. These studies are summarized in Table 20. The Western Governors' Association's Central Station Solar Task Force (CSSTF) projects that, with federal and state support, 4,000 MW of CSP could be deployed in the southwestern United States by 2015 (ASES 2007). To assess the longer-term impacts of these policies, ASES used NREL's Concentrating Solar Deployment System Model. With this model, ASES estimated that 30 GW of parabolic trough systems with thermal storage could deployed in the Southwest by 2030, if the 30% federal investment tax credit were extended to 2030. With a carbon tax of $35 per ton added to this tax credit, ASES estimated that 80 GW could deployed by 2030 (ASES 2007).

Table 20. Summary of CSP Resource Assessments

Study	Region	Year	MW	GWh*
CSSTF (ASES 2007)	Southwest	2015	4,000	13,300
NREL 2006	CA	2020	4,000	13,300
ASES 2007 (30% ITC)	Southwest	2030	30,000	99,900
ASES 2007 (ITC+CO_2)	Southwest	2030	80,000	266,000
RETI 2009	CA/NV/AZ	N/A	79,500	265,000

*Assumes an average capacity factor of 38%.

In a review of the economic, energy, and environmental benefits of CSP in California for NREL, Black & Veatch estimated that 4,000 MW of CSP could be installed in the state by 2020 (NREL 2006). The Renewable Energy Transmission Initiative (RETI) compiled a detailed inventory of sites with solar development potential in the Southwest. This study identified 326 potential CSP projects in California, representing 65,000 MW of generating capacity, as well as 34 projects in Nevada and Arizona, representing 14,500 MW of generating capacity (RETI 2009).

The amount of CSP added in the Reference and Transition Cases throughout the study period is shown in Table 3 in Section 2.

CSP Costs

AEO 2010 uses a current cost of $5,200 $/kW for CSP. Lazard 2008 estimates the cost of parabolic troughs between 4,500 and 5,900 $/kW and the cost of power towers between 5,000 and 6,300 $/kW. UCS 2009 uses 4,700 $/kW for 2015 projects, falling to 2,900 $/kW in 2030. In the Transition Scenario we use 4,700 $/kW for 2010 CSP projects without energy storage and $6,000 $/kW for projects with storage. In the Reference Case, we apply the average of these two costs (5,300 $/kW) to all CSP projects. Capacity factors for all new CSP projects rise from 38% in 2010 to 46% in 2050. Current and future costs in both scenarios are shown in Figure 3 in Section 2.

E. Biomass

A wide range of biomass fuels are used for energy production. First, there are various waste gases, methane rich gases emitted by landfills, wastewater treatment, and animal wastes. Second, there are solid waste streams: logging and sawmill wastes, crop residues and urban wood wastes. Third are dedicated energy crops – plants grown specifically to be used as fuel. Corn is currently the largest dedicated energy crop in the U.S., however it is used to make liquid fuel, not to generate electricity. While there has been considerable research on energy crops for electricity production, they are not yet grown on a widespread basis. Research has focused primarily on switchgrass and willow/poplar hybrids – and more recently on duckweed and water hyacinths (see Makhijani 2008).

The use of waste gases for energy production is not controversial, nor is the use of mill and urban wood wastes. These are considered “opportunity” fuels, free or lower cost byproducts of other activities. (In fact, the vast majority of mill wastes are already burned onsite for power and/or heat.) The use of the other biofuels listed above is extremely controversial. Use of logging wastes removes nutrients that would otherwise return to the soil and can exacerbate erosion problems on recently logged land. The use of crop residues removes nutrients from croplands resulting in more fertilizer use. Devoting land to dedicated energy crops can, in some cases, negatively impact animal habitats and/or the scenic and recreational value of the land. And all of these fuels-- timber and crop wastes and dedicated energy crops – are typically removed and transported by machines burning fossil fuels.

Another controversial issue is the carbon neutrality of biomass combustion. Growing plant matter absorbs CO_2 from the atmosphere, and burning that matter releases the CO_2 again. Thus, as long as a biomass feedstock is not burned faster than it regrows, it will be at least carbon neutral. Where fossil fuels are used to harvest and transport the fuel, the burn rate would need to be below the regeneration rate to maintain carbon neutrality. Dramatically expanding the use of biomass for fuel could lead to harvest rates in excess of regeneration rates. In light of this, state greenhouse gas accounting rules that consider biomass to be carbon neutral are increasingly coming under fire.

All of these concerns about biomass as an energy fuel are legitimate, and taken together, they lead to two important conclusions:

- First, in growing and harvesting biomass for energy use, we must carefully consider the full range of impacts.
- And second, we must use the biomass fuels we do harvest as efficiently as possible.

In light of these points, we are conservative in our use of this resource in the Transition Scenario. For comparison, we add a total of 23,000 MW of new biomass capacity by 2050, while in the Reference Case over 100,000 MW are added by 2050. In both scenarios, a substantial amount of new biomass capacity is CHP capacity at end-use sites.

There are a number of different conversion technologies for converting biomass into heat and/or power. Currently, fixed-bed boilers are most common in the U.S., and fluidized bed boilers are most common in Europe. Both technologies are fully mature and are commonly deployed on both large and small scales (EPA 2007).

Biomass can also be gasified and burned in internal combustion engines (ICEs) and gas turbines. Gasification offers several advantages. First, air emissions from burning gasified biomass, or “syngas,” are much lower than from a direct-fired plant (burning solid biomass). Second, it is much easier to transport gasified biomass (via pipeline) than solid biomass. However, gasification equipment adds costs to a project, and about 30% of the energy input is lost in the gasification process. Thus, we do not expect biomass gasification to become cost competitive with direct-firing and CHP during the study period.

The Biomass Potential

It is difficult to compare estimates of the biomass potential in the U.S., because assumptions must be made about how much of each type of biomass resource we are willing to use for energy. No two studies make exactly the same assumptions about this. We found five different estimates of the biomass energy potential in the U.S., three of which are summarized in Table 21. Of these studies, UCS 2009 is most conservative in its willingness to use biomass for electricity generation. The potential identified by the DOE study assumes a much greater willingness to use biomass.

Table 21. Estimates of the U.S. Biomass Potential

Study	Dry Tonnes per Year	mmBtu per year
EIA 2007	541,000	9,325,000
UCS 2009	334,000	5,748,000
DOE 2005	1,010,000	17,401,000

Note: A tonne, or metric ton, is equal to 2,200 pounds. We use an average heat content for biomass of 17.2 mmBtu per dry tonne, derived from the average of the heat contents of different types of biomass.

The fourth study, performed for NREL in 2005, is summarized in Table 22 below. NREL 2005 breaks biomass down into the following categories: crop residues, forest (logging) residues, primary[16] and secondary mill residues, urban wood residues, and dedicated energy crops. Regarding dedicated energy crops, NREL 2005 only includes the potential on on land that is not suitable for conventional crops and/or can provide erosion protection for agricultural set aside or Conservation Reserve Program (CRP) lands. The CRP, administered by the USDA Farm Service Agency, provides technical and financial assistance to eligible farmers and ranchers to address soil, water, and other related natural resource concerns on their lands.

The fifth study is a DOE analysis of opportunity fuels for CHP (DOE 2004), detailed in Table 22. This report looks in detail at a number of different waste-derived fuels.

In the Transition Scenario, our use of cellulosic biomass (non-gas) is guided primarily by NREL 2005, and our use of waste gases is guided by DOE 2004. Both of these studies make conservative but reasonable exclusions and provide a high level of detail in terms of both U.S. states/regions and different types of biomass. Table 22 shows the national biomass resource available for power generation by region, based on these studies. By 2050 we develop 50% to 70% of each region's crop and forest residues, mill wastes and urban wood wastes in each region. We develop up to 90% of the dedicated energy crop potential on CRP lands, and we develop up to 90% of each region's waste gas potential by 2050. Again, note that cellulosic biomass is burned in both direct-fire boilers and CHP systems.

[16] NREL estimates the net amount of primary mill waste available, excluding the large amount that is currently being used for energy at mills.

Table 22. NREL 2005 Estimate of Biomass Potential

	NREL 2005 Cellulosic Biomass (000 tonnes)	DOE 2004 Waste Gases (MW)
Northeast	297,000	1,780
Southeast	1,128,000	2,180
South Central	641,000	1,420
Eastern Midwest	1,729,000	3,210
Western Midwest	1,357,000	1,260
Northwest	205,000	1,180
Southwest	62,000	483
California	123,000	1,030
Total	5,541,000	12,500

Note: A tonne, or metric ton, is equal to 2,200 pounds. Numbers may not sum due to rounding.

Biomass Costs

For new direct fire biomass systems, we use the installed cost from AEO 2010, but we increase this cost 20% to account for higher construction and materials costs as discussed above. The result is 4,400 $/kW. We assume that installed costs come down by 20% by 2020 and come down 1% per decade after that, since this is a mature technology. We include fixed O&M of 67 $/kW-yr and variable O&M of 6.90 $/MWh and use a heat rate of 9,450 Btu/kWh – all from AEO 2010.

As noted, over 100,000 MW of biomass capacity is added in the Reference Case. First, we do not know how much of this is direct fire and how much is CHP. Thus, we cost out all the biomass generation in the Reference Case as direct-fire combustion. This is a conservative convention in that it will tend to understate the cost of the Reference Case, because direct-fire electric capacity is cheaper than CHP capacity. Second, because so much biomass is added in the Reference Case, we increase the average biomass fuel cost in the Reference Case from 2.00 to 3.00 $/mmBtu in the later decades. For direct-fire biomass in the Transition Scenario (23,000 MW) fuel costs stay at 2.00 $/mmBtu throughout the study period.

For the cost and performance of biomass CHP, we rely primarily on EPA 2007. This study provides a detailed analysis of biomass CHP technologies and their costs. We use the characteristics of a stoker boiler with a 600 ton per day capacity to represent biomass in the Transition Scenario. Fluidized bed boilers are quite common too, and the costs and performance of these is very similar to stokers.

EPA 2007 includes a cost of $4,900 $/kW for the stoker boiler. We increase this by 20% in 2010 for higher construction costs and bring it back down by 2020. Costs fall by 1% per decade after 2020. We use total non-fuel O&M costs of 36 $/MWh and fuel costs of 3.00 $/mmBtu to account for increased average distance to CHP sites relative to direct fire plant sites. See EPA 2007 for more on the operating characteristics of this plant type.

For anaerobic digester gas (ADG) and landfill gas (LFG) projects, we assume generation using an internal combustion engine, as we project this to be the lowest cost technology throughout the study period. We assume that third party developers pay landfill owners an average of 1.00 $/mmBtu for gas. For ADG projects we assume no gas cost. All costs and operating characteristics are based on ACEEE 2009b. Installed costs are increased by a factor of 1.25 to account for these specialized applications.

LFG projects are modeled on a 3-MW engine.[17] Installed costs are 1,400 $/kW, O&M is 1.8 cents per KWh, and the 2010 heat rate is 9490 Btu/kWh. Heat rate improvements over time are based on ACEEE 2009b. Wastewater treatment ADG projects are modeled on a 100 kW engine. Installed costs are 2,800 $/kW; O&M is 2.5 cents per kWh; and the 2010 heat rate is 12,000 Btu/kWh. For farm-based ADG systems we use capital costs of the digester and genset together of 5,150 $/kW (based on RETI 2008 and GDS Associates, et. al., 2007) and operating characteristics of an 800 kW generator. Total O&M is 3.0 cents per kWh; and the 2010 heat rate is 9,760 Btu/kWh.

F. Geothermal

There are two types of geothermal systems from which heat can be extracted to generate electricity. The system used depends on the site specific geological structure of the heat resource. The first type is hydrothermal, in which the geology and heat resource allow energy to be extracted with little additional work to move water through the system and up to the surface. In hydrothermal geothermal resources, super heated (200° C) water exists close to or at the earth's surface. These systems are also characterized by rocks with high permeability, allowing water to move easily within the system. To generate electricity, wells are drilled into the resource, and the hot water or steam is extracted and used to turn a turbine at the surface. The water is then returned to the resource where it can be reheated. All geothermal electric power plants currently in operation are hydrothermal systems.

The second type of system can extract energy from heat sources deeper below the earth's surface. These resources either lack water or are characterized by rocks with low permeability. Enhanced geothermal systems (EGS) work to create an engineered hydrothermal system through hydraulic fracturing. High pressure fluids are injected down a borehole until rock fractures at the depth of the resource. Once fractured, permeability is increased, and other wells are drilled. Water is pumped down through one well, becomes heated, and is forced back up to the surface through another well. There, the water is flashed to steam to turn turbines. Much greater amounts of heat can be accessed with EGS than with hydrothermal systems; however, hydrothermal technology is well established, while EGS is an emerging technology, and costs are less certain.

Finally, heat energy often becomes available when oil and gas wells are drilled, and recent research suggests that, in the case of existing wells, "co-produced" heat could be captured at much lower cost than with hydrothermal or EGS systems. The authors of

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[17] Data from EPA's Landfill Methane Outreach Program show an average project size of roughly 3 MW for existing LFG projects.

NREL's 2007 geothermal resource inventory write: "coproduced resources collectively represent the lowest-cost resources… reflecting the assumption that this potential can be developed using mostly existing well infrastructure" (NREL 2007, p. 16). However, serious efforts to capture this resource have only just begun, and more work is needed to determine exactly what infrastructure would need to be added to existing oil and gas fields.

The Geothermal Potential

We found three recent estimates of the technical potential of geothermal in the US, as shown in Table 23 below.

Table 23. Estimates of U.S. Technical Potential for Geothermal

Study	Resource	Capacity Potential (MW)
NREL 2007	Hydrothermal	27,600
USGS 2008	Hydrothermal	33,000
NREL 2007	EGS	58,700
USGS 2008	EGS	517,800
MIT 2007	EGS	1,249,000

The variations in these estimates stem largely from differing assumptions about economic and time constraints. The MIT projection of EGS capacity assumes that recovery of up to 2% of the theoretical resource is feasible.

In addition to these estimates of technical potential, two studies have assessed the amount of economic geothermal capacity in the U.S. First, the MIT study cited above estimates that 100,000 MW of EGS capacity would be cost effective based on specific assumptions regarding the cost of EGS development and avoided energy costs. Second, a Western Governors' Association geothermal task force estimates that 5,600 MW of hydrothermal capacity could be developed economically over ten years in 13 western states, and that 13,000 MW could be available at or under 80 $/MWh in 20 years (ASES 2007).

In order to produce electricity efficiently either with a hydrothermal or an enhanced system, the geothermal resource must be at least 110°C, although generation with temperatures as low as 80°C is possible in special circumstances (NREL 2007). The temperature of the earth increases with depth at an average rate of 30°C per kilometer. The rate of temperature increase is influenced by geological conditions, mainly relating to tectonic activity. Geothermal energy is easier and less expensive to extract in areas with high temperature gradients. The temperature of the earth at depths of 6.5 and 10 kilometers is shown in Figure 26, from MIT 2007. These maps suggest that significant development of geothermal resources in much of the eastern US would require major advances in drilling technology.

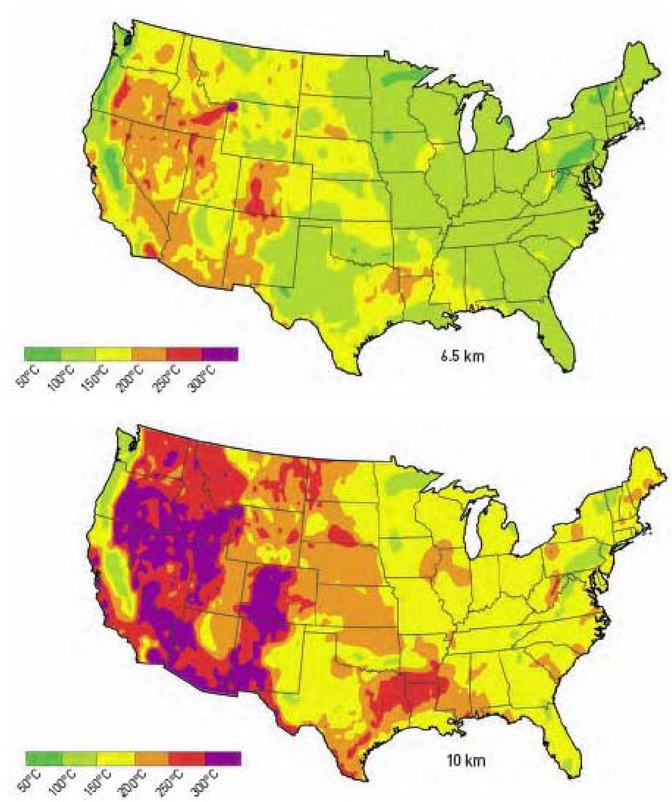

Figure 26. Average Temperature of Earth at 6.5 km Depth. *Source: MIT 2007.*

Geothermal Costs

NREL 2007 provides a detailed analysis of the U.S. geothermal resource and the cost of capturing it in different places. This study produced the supply curve shown in Figure 27. The dashed line is a previous estimate, and the solid line is NREL's 2007 estimate. Within the chart, "HT F" and "HT B" refer to hydrothermal technologies; "CoP" refers to co-produced resources; and "EGS" refers to enhanced systems.

While this is the national supply curve, NREL 2007 presents data by region. Because of the technological and geographic detail within these data, we have used them to characterize regional geothermal costs in both of our scenarios and the costs and potential in the Transition Scenario.

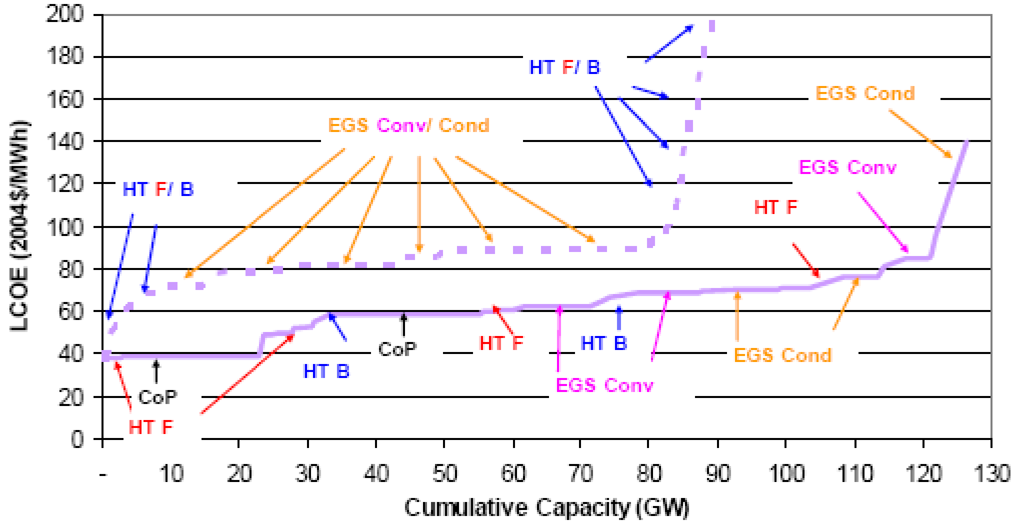

Figure 27. U.S. Geothermal Supply Curve from NREL 2007

In 2009, UCS worked with the authors of the NREL study to develop a 2010 curve, increasing costs to account for higher construction and materials costs (see UCS 2009, Appendix D). In addition, UCS assumed that co-produced resources are not available in 2010, based on the limited experience to date with these systems. To develop our 2010 supply curve, we started with the NREL supply curve as adjusted by UCS. We then assumed that roughly half of the co-produced resources become available in 2020, and that all of the co-produced resources become available in 2030. Our supply curves for 2010, 2030, and 2050 are shown in Figure 28.

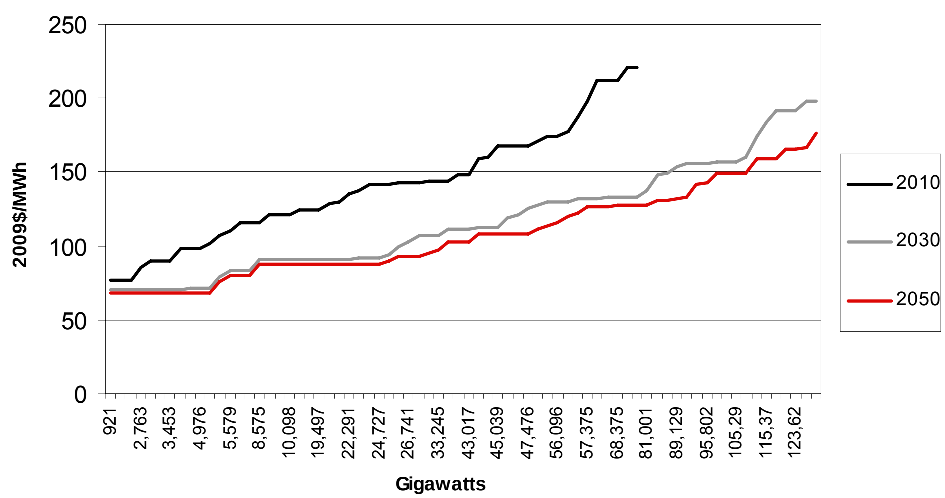

Figure 28. Geothermal Energy Supply Curves

Note that our 2010 curve starts at 77 $/MWh while the NREL curve starts around 40 $/MWh. This is the result primarily of higher assumed real costs (from construction and materials costs) but also of the conversion from 2004 to 2009 dollars. The significant shift of our supply curve between 2010 and 2030 is primarily the result of adding co-produced resources into the available supply, however we also assume cost reductions from falling construction and materials cost in the near term and R&D and learning over the long term.

7. Appendix C: Data Tables

Tables 24 through 33 below show the data on which selected charts in the study are based. Table 34 shows the cost of supply-side resources by type in the Reference Case and Transition Scenario. Totals may not sum due to rounding.

Table 24. The Resource Mix in the Transition Scenario, from Figure 4 (TWh)

	2010	2020	2030	2040	2050
Coal	1,830	1,560	1,030	521	0
Gas	856	881	797	786	819
Nuclear	813	827	811	726	594
Hydro	271	299	301	306	315
Biomass	56	122	186	249	312
Wind	110	366	553	711	932
Geothermal	18	31	58	88	112
Gas CHP	0	30	84	158	256
Solar	4	37	78	118	172
Other	73	62	62	63	63
Totals	4,030	4,210	3,960	3,730	3,580

Table 25. The Resource Mix the Reference and Transition Cases from Figure 5 (TWh)

	2010	2030 Reference	2030 Transition	2050 Reference	2050 Transition
Coal	1,830	2,210	1,030	2,500	0
Gas	856	1,020	797	1,320	819
Nuclear	813	886	811	951	594
Hydro	271	302	301	315	315
Biomass	56	293	186	470	312
Wind	110	207	553	244	932
Geothermal	18	26	58	33	112
Gas CHP	0	0	84	0	256
Solar	4	21	78	36	172
Other	73	74	62	77	63
Totals	4,030	5,030	3,960	5,940	3,580

Table 26. The Northeast in the Reference and Transition Cases, from Figure 9 (TWh)

	2010	2030 Reference	2030 Transition	2050 Reference	2050 Transition
Coal	150	170	61	190	0
Gas	130	170	130	240	140
Nuclear	190	210	170	210	53
Hydro	33	36	36	38	38
Biomass	14	55	27	84	36
Wind	15	38	80	41	160
Geothermal	0	0	0	0	0
Gas CHP	0	0	10	0	44
Solar	1	4	13	8	29
Other	16	16	15	15	15
Totals	550	690	540	830	510

Table 27. The Southeast in the Reference and Transition Cases, from Figure 10 (TWh)

	2010	2030 Reference	2030 Transition	2050 Reference	2050 Transition
Coal	460	580	330	670	0
Gas	260	300	260	340	280
Nuclear	290	330	300	380	300
Hydro	34	36	36	38	38
Biomass	24	83	55	160	82
Wind	2	11	31	15	69
Geothermal	0	0	10	0	24
Gas CHP	0	0	26	0	78
Solar	0	4	13	6	35
Other	25	26	26	27	26
Totals	1100	1,400	1100	1,600	930

Table 28. The Eastern Midwest in the Reference and Transition Cases, from Figure 11 (TWh)

	2010	2030 Reference	2030 Transition	2050 Reference	2050 Transition
Coal	640	760	400	840	0
Gas	76	85	76	130	99
Nuclear	180	190	190	190	190
Hydro	6	7	7	9	9
Biomass	6	60	42	93	80
Wind	13	29	99	39	190
Geothermal	0	0	0	0	0
Gas CHP	0	0	21	0	73
Solar	0	1	4	2	9
Other	6	7	7	7	7
Totals	920	1,100	840	1,300	650

Table 29. The Western Midwest in the Reference and Transition Case, from Figure 12 (TWh)

	2010	2030 Reference	2030 Transition	2050 Reference	2050 Transition
Coal	120	150	70	160	0
Gas	6	8	6	10	15
Nuclear	24	25	25	25	25
Hydro	12	13	13	14	14
Biomass	2	57	27	84	58
Wind	11	11	82	11	140
Geothermal	0	0	0	0	0
Gas CHP	0	0	3	0	8
Solar	0	0	3	0	7
Other	1	1	1	2	1
Totals	170	260	230	310	270

Table 30. The South Central in the Reference and Transition Cases, from Figure 13 (TWh)

	2010	2030 Reference	2030 Transition	2050 Reference	2050 Transition
Coal	250	300	110	320	0
Gas	210	230	210	280	210
Nuclear	49	61	61	69	27
Hydro	6	7	7	7	7
Biomass	3	11	13	17	23
Wind	30	30	110	30	190
Geothermal	0	0	9	0	27
Gas CHP	0	0	9	0	23
Solar	0	2	10	4	26
Other	7	7	7	7	7
Totals	550	640	540	730	540

Table 31. The Northwest in the Reference and Transition Cases, from Figure 14 (TWh)

	2010	2030 Reference	2030 Transition	2050 Reference	2050 Transition
Coal	73	81	4	98	0
Gas	44	46	32	71	12
Nuclear	9	9	9	9	0
Hydro	130	150	150	150	150
Biomass	3	13	8	15	13
Wind	12	16	61	34	76
Geothermal	2	2	9	2	16
Gas CHP	0	0	3	0	4
Solar	0	1	3	2	4
Other	0	0	0	0	0
Totals	280	320	280	390	280

Table 32. The Southwest in the Reference and Transition Cases, from Figure 15 (TWh)

	2010	2030 Reference	2030 Transition	2050 Reference	2050 Transition
Coal	120	150	58	230	0
Gas	62	78	54	74	46
Nuclear	23	23	23	23	0
Hydro	14	15	15	16	16
Biomass	1	5	4	9	6
Wind	5	7	24	10	35
Geothermal	1	1	3	2	16
Gas CHP	0	0	7	0	16
Solar	1	2	18	3	40
Other	0	1	1	1	1
Totals	220	280	210	370	180

Table 33. California in the Reference and Transition Cases, from Figure 16 (TWh)

	2010	2030 Reference	2030 Transition	2050 Reference	2050 Transition
Coal	24	26	0	28	0
Gas	74	100	37	130	25
Nuclear	43	43	43	43	0
Hydro	35	38	38	39	39
Biomass	6	9	10	12	14
Wind	22	65	71	84	71
Geothermal	14	22	26	30	30
Gas CHP	0	0	5	0	10
Solar	2	7	14	12	22
Other	7	7	6	7	6
Totals	230	320	250	380	220

Table 34. Comparison of Supply-Side Costs by Resource and Year (million 2009$)

	2010	2020	2030	2040	2050
Reference Case					
Coal	78,442	80,800	83,214	91,345	98,056
Natural Gas	40,374	44,994	72,452	113,495	163,722
Nuclear	45,262	51,945	56,836	63,153	72,421
Geothermal	0	339	524	857	1,169
Biomass	0	7,604	15,350	20,178	27,371
CSP	0	140	162	208	167
PV Distributed	0	3,563	4,023	3,365	4,315
PV Central	0	70	143	161	186
LFG/WWT Gas	0	334	334	381	216
Wind	0	5,206	5,574	4,816	6,158
Reference Case Total	*164,078*	*194,997*	*238,612*	*297,958*	*373,779*
Transition Scenario					
Coal	78,442	59,207	37,197	18,783	0
Gas	40,374	51,744	54,135	64,836	86,701
Nuclear	45,262	46,070	45,173	40,453	33,073
Wind	0	14,683	23,604	24,643	30,325
Offshore Wind	0	1,992	3,065	5,033	8,529
PV Distributed	0	5,433	8,932	8,897	11,757
PV Central	0	1,196	2,711	3,353	4,701
CSP no storage	0	857	1,708	2,372	2,432
CSP storage	0	773	1,664	2,356	2,464
Biomass CHP	0	4,310	7,331	10,829	14,823
LFG	0	921	1,083	1,379	1,250
ADG WWT	0	267	578	930	1,073
ADG Farm	0	419	1,052	1,823	2,272
Gas CHP	0	2,481	7,313	14,829	25,671
Geothermal	0	1,521	3,884	6,603	8,569
Biomass DF	0	2,091	4,249	5,789	7,304
Transition Scenario Total	*164,078*	*193,966*	*203,680*	*212,907*	*240,946*
Net Cost of Transition	***0***	***-1,000***	***-35,000***	***-85,000***	***-130,000***

This table shows the calculation of the net cost of the supply-side resources in the Transition Scenario. In other words, we calculate the difference in cost between the Reference Case and Transition Scenario. Net costs are rounded to two significant figures and presented in the first row of Table 8. Because we focus on the difference in costs, we only include resources that produce different amounts of energy in the two scenarios. Any resource that produces the same amount will have a net cost of zero. All renewable resources online in 2010 fall into this category; therefore the cost of renewable resources in 2010 is zero. Coal, gas and nuclear also net to zero in 2010, but we show those costs here for context. After 2010, the two scenarios begin to diverge. Existing coal, gas and nuclear resources are utilized differently, and new resources are developed differently. The cost of energy efficiency and other aspects of the Transition Scenario are shown in Table 8.

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