APPENDIX 9

minnesota power

AN ALLETE COMPANY

2013 Resource Plan

March 1, 2013
Docket No. E015/RP-13-53

minnesota power / 30 west superior street / duluth, minnesota 55802-2093 / 218-722-5642 / www.mnpower.com

Lori Hoyum
Policy Manager
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March 1, 2013

VIA E-FILING
Dr. Burl W. Haar Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Re: In the Matter of Minnesota Power's Application for Approval of its 2013-2027 Resource Plan
Docket No. E015/RP-13-53

Dear Dr. Haar:

Minnesota Power presents for approval its 2013 Integrated Resource Plan ("2013 Plan" or "Plan") pursuant to the requirements set forth in the Minnesota Public Utilities Commission's ("Commission") Orders dated May 6, 2011 and September 13, 2012 in Docket No. E015/RP-09-1088. This Plan is being filed under Minn. Stat. § 216B.2422 and Minn. Rules Chapter 7843.

Minnesota Power's 2013 Plan is focused on a balanced approach to delivering safe, reliable service at the lowest possible cost to customers while protecting and improving the region and state's quality of life through continued environmental stewardship. It continues the transition of Minnesota Power's fleet to become more diverse, more flexible and less emitting with additional major steps that address a changing energy landscape and respond to the Commission's Orders in Minnesota Power's previous integrated resource plan docket. Minnesota Power's short-term action plan during the five-year period of 2013 through 2017 is comprised of steps that will: a) preserve competitive base load generating resources while reducing emissions, b) continue implementation of least cost demand side resources including conservation, c) reduce reliance on coal fired generation, d) reduce carbon intensity on Minnesota Power's system and e) add renewable energy and transmission infrastructure to the benefit of customers. The Company's long-term action plan strategy will focus on further reducing carbon emissions in its portfolio and reshaping its generation mix towards a balance of approximately one-third renewable resources, one-third efficient coal-fired generation and one-third natural gas/other sources.

The 2013 Plan is organized into six sections with supporting appendices as presented in the Table of Contents. The supporting appendices contain in-depth or extensive information and, as appropriate, specific responses to the Orders dated May

6, 2011 and September 13, 2012, respectively, including all agreed-to actions by Minnesota Power.

Certain portions of the Plan contain trade secret information and are marked as such, pursuant to the Commission's Revised Procedures for Handling Trade Secret and Privileged Data, which procedures further the intent of Minn. Stat. § 13.37 and Minn. Rule 7829.0500. As required by the Commission's Revised Procedures, a statement providing the justification for excising the Trade Secret Data is attached to this letter.

As reflected in the attached Affidavit of Service, the Executive Summary has been filed on the official general service list utilized by Minnesota Power as well as the 2010 Integrated Resource Plan service list.

Please contact me at the number or the email address provided if you have any questions.

Yours truly,

Lori Hoyum

Lori Hoyum

cc: Service List

STATE OF MINNESOTA	)	AFFIDAVIT OF SERVICE VIA
	) ss	ELECTRONIC FILING
COUNTY OF ST. LOUIS	)	

Susan Romans of the City of Duluth, County of St. Louis, State of Minnesota, says that on the 1st day of March, 2013, she served Minnesota Power's 2013 Integrated Resource Plan in Docket No. E015/RP-13-53 to the Minnesota Public Utilities Commission via electronic filing. The remaining parties were served as so indicated on the attached Official Service List.

*/s/ Susan Romans*___________

Subscribed and sworn to before
me this 1st day of March, 2013.

*/s/ Jodi Nash*_______________
Notary Public - Minnesota
My Commission Expires Jan. 31, 2015

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Andrew	Moratzka	apm@mcmlaw.com	Mackall, Crounse and Moore	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 55402	Paper Service	Yes	OFF_SL_13-53_E015-RP-13-53

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STATEMENT REGARDING JUSTIFICATION FOR EXCISING TRADE SECRET INFORMATION

Pursuant to the Commission's revised Procedures for Handling Trade Secret and Privileged Data in furtherance of the intent of Minn. Stat. § 13.37 and Minn. Rule 7829.0500, Minnesota Power has designated portions of its attached 2013 Integrated Resource Plan ("Plan") as Trade Secret.

Minnesota Power is requesting approval of its Plan under Minn. Stat. § 216B.2422 and Minn. Rules Chapter 7843. Minnesota Power has removed certain information from the Plan to prevent disclosure of Minnesota Power's information regarding its methods, techniques, and process for identifying, obtaining, managing, and comparing various resources. This is highly confidential information; Minnesota Power's competitors, as well as its potential suppliers, would gain a commercial advantage over Minnesota Power if this information were publicly available. Minnesota Power follows strict internal procedures to maintain the secrecy of this information in order to capitalize on economic value of the information to Minnesota Power. As a result of public availability, Minnesota Power and its customers would suffer in providing resources to its retail load. Minnesota Power respectfully requests the opportunity to provide additional justification in the event of a challenge to the trade secret designation provided herein.

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

MINNESOTA POWER 2013 RESOURCE PLAN

PETITION FOR APPROVAL

March 1, 2013

Docket No. E015/RP-13-53

Table of Contents

Table of Figures:

Table of Tables

Table of Appendices

I. About Minnesota Power

Minnesota Power, in its second century of energizing communities and businesses, is transforming its energy supply by bringing more renewable power to customers while reducing its reliance on coal.

A division of ALLETE, Inc., Minnesota Power serves about 144,000 retail electric customers and 16 municipal systems across a 26,000-square-mile service area in central and northeastern Minnesota. ALLETE subsidiary Superior Water, Light and Power ("SWLP") sells electricity to 15,000 customers, natural gas to 12,000 customers and water services to 10,000 customers in northwestern Wisconsin.

More than half of Minnesota Power's total energy supply is sold to industrial customers who operate around the clock. This ratio of industrial demand gives Minnesota Power a uniquely high load factor and a load profile with less variation than most utilities. The Company's industrial customers produce taconite, iron nuggets, paper and pulp, and serve the pipeline and refining industry.

Minnesota Power has nine Large Power contracts serving 10 customer locations which include: five taconite producing facilities, one iron nugget plant and four paper and pulp mills. The processing of taconite, an iron-bearing rock used to make pellets which are a primary ingredient in blast furnace steel, requires large quantities of electric power. A new mining customer, Mesabi Nugget, produces iron-bearing nuggets. PolyMet, a nonferrous mining operation awaiting final permitting, is also under contract to purchase electricity from Minnesota Power. Another new mining customer, Essar Steel Minnesota, obtains its electricity from the municipality of Nashwauk, which is served as a municipal customer by Minnesota Power. The Essar facility under construction is expected to begin processing taconite this year. In addition to directly serving three major paper and pulp mills, Minnesota Power indirectly serves another mill with wholesale service. Minnesota Power also powers four wood products manufacturers and provides electric service to two oil pipelines and a refinery.[1] Minnesota Power is expected to remain a winter-peaking utility for the foreseeable future, as residential customers account for less than 10 percent of total and do not have the influence on overall demand seen with summer peaking utilities.

Factors that support the steadiness and predictability of Minnesota Power's electric load contribute to the Company's comparatively low-cost power. According to 2012 statistics[2] compiled by the Edison Electric Institute, Minnesota Power's total average retail electric rate of 5.97 cents per kilowatt-hour was the fourth lowest in the U.S. among 169 providers surveyed. Minnesota Power's retail electric rate was the second-lowest in the West North Central region (average rate: 7.87 cents per kWh) and the lowest in Minnesota (average: 8.09 cents per kWh).

Minnesota Power generates the majority of its electricity from coal-fired units at the Boswell, Laskin and Taconite Harbor Energy Centers in Minnesota, supplemented

[1] The refinery is one of the 15,000 customers SWLP sells electricity to in northwestern Wisconsin.
[2] Typical Bills and Average Rates Report Summer 2012, dated July 1, 2012.

by a long-term purchase from Square Butte’s Milton R. Young 2 (“Young 2”) lignite coal generating station in North Dakota. But the percentage of coal-based generation on the Minnesota Power system is declining, from about 95 percent in 2006 to approximately 80 percent today. The Company anticipates reaching a coal, non-coal balance of 50/50 by 2025 and a long-term state of approximately one-third renewable resources, one-third natural gas/other, and one-third coal. Minnesota Power is working toward a more diverse mix of energy producing technologies and fuels to provide its customers with a reliable supply of electric energy at reasonable cost.

Building off the company-founding hydroelectric assets, over the past six to seven years, the Company has undertaken a systematic effort to increase its deployment of renewable energy. In 2006 and 2007, Minnesota Power began purchasing the entire output of the Oliver 1 and Oliver 2 wind farms built in North Dakota by NextEra Energy. In 2008, Minnesota Power built Taconite Ridge, the first commercial wind generating facility in northern Minnesota. Most recently, the Company completed three phases of the Bison Wind Energy Center in North Dakota between 2010 and 2012. All told, these wind projects added more than 400 MW of renewable electricity to Minnesota Power’s system.

As the state’s largest producer of hydroelectric power with 10 federally licensed facilities, Minnesota Power is well acquainted with the power of water. The Company in 2011 signed a 15-year agreement to buy 250 MW of carbon-free hydroelectricity from Manitoba Hydro beginning in 2020. Minnesota Power is planning the construction of the Great Northern Transmission Line to carry this Canadian hydropower to the Mesabi Iron Range and Duluth which will also improve regional reliability.

Minnesota Power has utilized innovation and synergy in balancing its generation fleet. It purchased a 465-mile direct current transmission line linking energy resources in North Dakota to Duluth and began phasing out a long-term purchase of coal-based electricity replacing it with wind power from the new Bison project. A creative provision of Minnesota Power’s energy purchase from Manitoba Hydro will allow the Company to “store” North Dakota wind energy within the Manitoba system.

Minnesota Power has partnered with large industrial customers to create cogeneration using wood resources from the region. These cogeneration facilities take advantage of the synergies in process steam and electric production and include the Rapids Energy Center at the Blandin Paper Company in Grand Rapids, Minnesota, and the Cloquet Sappi No. 5 Turbine at the Sappi facility in Cloquet, Minnesota. Minnesota Power’s Hibbard Energy Center in Duluth, Minnesota uses a mix of wood, natural gas and coal to supply steam to the NewPage paper-making facility and to Minnesota Power’s Units 3 and 4 turbine generators.

Another facet of the Company’s generation fleet transition involves further reducing the emissions from the two largest baseload coal generators on the system. A major environmental retrofit completed at Boswell Energy Center Unit 3 (“BEC3”) in 2009 will be followed by a similar emission reduction project at Boswell Energy Center Unit 4 (“BEC4”). Decisions regarding Minnesota Power’s Laskin and Taconite Harbor generating facilities are thoroughly detailed elsewhere in this plan. These facilities have served the Company and its customers well. Just as the Company developed from a 100 percent hydroelectric provider after its incorporation in 1906, Minnesota Power will continue to evolve its power supply, seeking a sustainable balance of energy generation that is dependable, affordable and environmentally sound to best serve its customers.

II. 2013 Resource Plan Summary

This Petition presents Minnesota Power's Integrated Resource Plan ("Plan" or "2013 Plan") for the period 2013 through 2027. The Plan is filed pursuant to Minn. Stat. § 216B.2422, the Minnesota Public Utilities Commission's ("Commission") May 6, 2011 Order on Minnesota Power's 2010 Integrated Resource Plan ("2010 Plan") and its September 13, 2012 Order on Minnesota Power's baseload diversification compliance filing (Docket No. E015/M-09-1088).

Minnesota Power is pleased to submit its 2013 Integrated Resource Plan ("IRP"), the next chapter in the company's *Energy**Forward*** resource strategy, designed to supply its customers with a safe, reliable, and affordable power supply while reducing coal fleet emissions, sustaining its high quality energy conservation program, adding renewables in the near term and adding natural gas in the long-term. Minnesota Power's *Energy**Forward*** strategy is reshaping the company's power supply from a predominantly coal-based energy mix to one that is diverse while minimizing customer costs and retaining reliability.

Minnesota Power finds itself in a very different planning position than most of the electric industry as it is forecasting system growth in a time of recession recovery. Taconite production levels have generally recovered, economic diversification in the way of alternative mining and forest industry product facilities have begun operating and more new operations are on the horizon in Northeast Minnesota. The continued reduction in power demand seen in the rest of the industry plus abundant supplies of coal and natural gas are resulting in historic lows in electric power market prices. This is producing an outlook for competitively priced surplus power that creates a valuable opportunity to help Minnesota Power keep power supply costs low through select and well-timed bilateral purchases as it implements its resource plans, especially nearer term.

Proactive environmental control investments to date, along with more recent engineering design work on plant retrofits, will enable Minnesota Power to timely address environmental regulations, including the finalized Environmental Protection Agency ("EPA") Mercury and Air Toxics ("MATS") Rule.[3] The Company has been and will continue to concentrate additional environmental control investment on its largest, most efficient resources to help ensure cost effective investments on behalf of customers.

[3] Under Section 112 of the Clean Air Act, the EPA is required to set emission standards for air pollutants for certain source categories. The EPA published the final MATS Rule in the Federal Register on February 16, 2012, addressing mercury and other emissions from coal-fired utility units greater than 25 MW.

Minnesota Power's 2013 Plan is focused on a balanced approach to delivering safe, reliable service at the lowest possible cost to customers while protecting and improving the region and state's quality of life through continued environmental stewardship. Additionally, the themes of the 2013 Plan reflect the Company's long-held resource planning principles and strategic goals, while meeting regulatory and legislative objectives. This Plan:

- Preserves reliable and environmentally compliant service to meet customer needs. Through implementation of a diverse and flexible resource mix of renewable, coal and natural gas supplies, Minnesota Power will balance its fuel sources and be well positioned to meet the needs of its customers.

- Further improves environmental performance through ongoing and significant mercury and other air emission reductions.

- Cost effectively serves increasing customer load requirements while reducing carbon intensity per unit of energy delivered through an optimum mix of effective customer conservation programs, reduced reliance on coal, generating facility efficiency improvements, added development and acquisition of innovative renewable energy sources from wind, water and wood and the addition of natural gas in the long term. Minnesota Power will reduce carbon emissions by about 30 percent on its system in 2015 while serving about 20 percent more load, exceeding the 2015 state goal for carbon reduction by 15 percent.[4]

- Protects affordability through power supply actions that maintain competitive electric service rates for Minnesota Power's customers. The 2013 Plan demonstrates through a first of its kind rate outlook that the Plan is cost effective in meeting customer needs even as Minnesota Power meets its forecasted growth and complies with environmental and energy policies.

- Specifically addresses resource planning Order requirements as detailed in Minnesota Power's 2010 Plan Order and its 2012 baseload diversification study ("BDS") Order. Relative to the baseload diversification study in particular, the 2013 Plan addresses:

    i. *A proposal to address the viability of Laskin Energy Center, Units 1 and 2 ("LEC"), and Taconite Harbor Energy Center, Unit 3 ("THEC3").* With Commission Approval, Minnesota Power plans to convert LEC to a gas peaking facility and it plans to retire THEC3 as described in this Plan.

    ii. *An evaluation of the consequences – including all relevant costs and the consequences for transmission adequacy – of retiring Boswell Energy*

[4] Minn. Stat. § 216H.06, Subd. 1, states, "It is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050. The levels shall be reviewed based on the climate change action plan study."

Center, Units 1 and 2 ("BEC1&2") by 2020. Minnesota Power's analysis in this Plan shows that BEC1&2 are an integral highly economic part of the Boswell Energy Center ("BEC") providing station electric and water service, and benefit from site economies of scale. BEC1&2 remain valuable customer assets for customers.

iii. *Scenarios that add 100 to 200 MW of wind capacity in the 2014-2016 time frame.* A very recent federal production tax credit ("PTC") extension[5] and projected customer load growth have created the dynamic for further wind supplies to be considered for Minnesota Power's portfolio. In the short-term action plan contained in this Petition, Minnesota Power is investigating taking this opportunity to create additional cost effective renewable supply for its customers by issuing a request for proposal for up to 200 MW of wind energy in service in the 2014-15 timeframe.

iv. *Scenarios that add 400 to 600 MW of natural gas capacity in the 2014-2016 time frame.* As this Plan illustrates, a natural gas combined cycle unit is not economic for Minnesota Power's customers prior to 2020 largely due to an industry surplus of economic power. However, natural gas combined cycle technology is in the long-term planning horizon and will likely be Minnesota Power's next large power supply addition beyond 2020.

v. *A comprehensive socioeconomic impact analysis by customer class in conformance with the Commission's resource planning rules.* Minnesota Power is sensitive to the economic health of its service territory. Indeed, given its natural resource economic base, Minnesota Power's service territory employment is particularly sensitive to economic swings and global competition. Jobs in heavy industry, including those at Minnesota Power, are a key economic driver of the region's economy. As the region's power provider, Minnesota Power plays an important role in its communities through being an employer, tax revenue source, and purchaser of vendor services. The economic impact to the region and communities of generating unit closure alternatives at LEC and THEC3 were evaluated and helped quantify the vital role that Minnesota Power's generation facilities play in the region.

vi. *Rate impact projection order point.* Minnesota Power has included a projected rate impact by major customer class for its short-term action plan as a first of kind forward look at future rate projections due to the changes in power supplies outlined in Minnesota Power's 2013 Plan.

[5] The wind energy production tax credit ("PTC") was extended by President Obama on January 2, 2013 as part of the American Taxpayer Relief Act of 2012 legislation. The PTC is available to wind energy production facilities that begin construction prior to January 1, 2014.

Minnesota Power's 2013 Plan continues the transition of Minnesota Power's fleet toward more diversity, more flexibility and less emissions with additional major steps that address a changing energy landscape and respond to the Commission's Orders in Minnesota Power's previous IRP Docket. The need for Minnesota Power's industrial customers to be globally competitive combined with the inherent cyclicality of these natural resource based industries, along with the knowledge that environmental regulation will continue to be a major factor in energy supply decisions, requires Minnesota Power to thoughtfully consider and plan for its existing and future resource mix in a transformational way. The 2013 Plan helps to ensure that Minnesota Power remains well positioned under most economic and regulatory scenarios to best serve the needs of its customers large and small.

Key Items Shaping the 2013 Plan

The Commission's September 13, 2012, Order[6] concluded Minnesota Power's 2010 IRP, accepted Minnesota Power's Baseload Diversification Report[7] filed on February 6, 2012, and folded further consideration of the study into Minnesota Power's next resource planning docket. Additionally, the Order closed the 2010 Plan.[8] Minnesota Power's study provided high level, benchmark understanding of projected environmental challenges and uncertainties facing LEC and THEC3 over the next decade. The study also provided initial insight into estimated customer power supply cost trends using gross assumptions about retrofit infrastructure and high level estimation of plant retrofits and replacement energy supplies. The study underscored the pivotal impact and fluid nature of assumptions made about key drivers such as carbon penalties and natural gas pricing on the viability of LEC and THEC3 and on the risks and costs of their potential replacements. The study identified the value to customers of Minnesota Power's well-maintained, environmentally well-controlled units. The study also provided direction on how to refine the analysis of future resource alternatives such as natural gas and additional wind in order to identify the power supply resources that are projected to best meet Minnesota Power customer needs in the future. Further, the study provided additional forums for stakeholder input. While the study did the assessments that the Commission's 2010 Plan Order requested, the study itself was necessarily only exploratory and largely provisional, especially given the absence of any final pertinent EPA environmental rule information when it was developed.

Figure 10 on page 35 illustrates the role and context of the study within the overall resource planning process for LEC and THEC3 and what key decision making information for action around LEC and THEC3 and potential replacement resources will stem from the Plan filed in this Petition. Unlike the Report, Minnesota Power's 2013 Plan provides the level of information necessary to allow the Commission to meet its

[6] Docket No. E015/M-09-1088
[7] Minnesota Power's Baseload Diversification Report provides a summary of its baseload diversification study findings.
[8] Docket No. E015/M-09-1088

responsibilities under the statutes and rules relative to resource decision making on LEC and THEC3 in the public interest.

Integrated Resource Plan Process Streamlining

As the pace of change in the nation's energy landscape quickens, so has that of Minnesota Power in developing its 2013 resource plan so that it will support timely decisions on key aspects of the Company's energy supply. To that end, Minnesota Power's 2013 Plan offers several first of kind features to enable effective and comprehensive stakeholder input and efficient consideration and decision making. These actions include:

- Filing the Company's load forecast and load and capability calculation in advance of the overall 2013 Plan.
- Parallel filing of large datasets utilized in the evaluation and analysis, including Strategist software input and output files, along with detailed scripts on Minnesota Power's analysis process.
- Commitment to a two-month initial comment and one-month reply comment period in order to facilitate action on the 2013 Plan in a timely manner.
- Provision of projected customer rate impacts due to changes in power supplies reflected in the short-term action plan.

Creating a More Flexible and Diverse Fleet

As noted, Minnesota Power's resource strategy includes a major evolution from a primarily coal-based fleet to a more balanced and flexible set of resources. A more balanced and flexible fleet will provide Minnesota Power the capability to meet customers' needs reliably and cost-effectively while still managing the inherent variability of large industrial customer business cycles. Minnesota Power is aiming for an energy mix of approximately one-third renewable resources such as wind, wood and hydropower, one-third natural gas/other and one-third coal for its long-term position. Diversification of the Company's fleet is already well underway with much of the progress attributed to the successful implementation of its renewable plans, including wind and wood additions plus Minnesota Power's 250 MW power purchase agreement ("PPA") with Manitoba Hydro.

Wisely Planning for Growth and Inherent Business Cycles

Historically, Minnesota Power has been required to flexibly respond to business cycles, including large increases and decreases in load due to business cycles. This need for flexibility will continue and will be combined with a forecast for growth in the current planning period. In order to account for system growth while retaining its historical business cycle flexibility, Minnesota Power evaluated four forecast scenarios. Three of the scenarios centered around variations of load growth, while the remaining scenario examined load contraction. The evaluation showed Minnesota Power will have the power it needs to serve large load additions under various timing requirements while providing those customers with the cost effective electricity they depend upon. Minnesota Power will also have a more flexible fleet to provide contingency capability during business cycles.

Sound Coal Unit Direction

Minnesota Power's small coal unit plan aligns well with the Company's vision of achieving an energy mix of one-third renewable resources, one-third natural gas/other, and one-third coal in the long term. Minnesota Power has determined that 185 MW of coal generation from its small coal-fired facilities is not cost effective to retrofit with environmental controls. Instead, Minnesota Power plans to cease coal energy conversion at the 75 MW THEC3 and refuel the 110 MW LEC with natural gas in 2015. Minnesota Power's newer and larger BEC3 and BEC4 remain core assets that supply large volumes of cost effective energy to Minnesota Power customers 24 hours a day. The BEC4 Environmental Retrofit Project ("BEC4 Project") currently before the Commission[9] will help to sustain the essential BEC4 resource for customers in an environmentally compliant manner. BEC1 & 2, part of the Boswell Energy Center ("BEC") system and Taconite Harbor Energy Center Units 1 and 2 ("THEC1 & 2"), are environmentally compliant and more efficient as a result of prior investments in environmental control technology.

Competitive Renewable Supply Ahead of RES Target

With strong regulatory support, and through wise planning and capitalizing on the very economical opportunities, Minnesota Power is ahead of schedule in meeting its requirement to have 25 percent of projected 2025 retail and wholesale electric sales from Minnesota-eligible renewable resources. Minnesota Power constructed and placed into operation three large and cost effective wind farms located in North Dakota - the Bison 1, 2 and 3 Wind Projects. Given the recent Congressional extension of the PTC, one additional wind project is anticipated in North Dakota to complete this element of the Company's renewable expansion plans. The Company continues to evaluate other renewable options including solar, biomass, battery storage, and cost-effective wind projects located in and around Minnesota.

Natural Gas Additions and Market Purchases: Well-timed to Optimize Opportunities

Minnesota Power plans to incorporate a natural gas combined cycle resource into its power supply portfolio when the timing is right. Presently, the Company plans to add 200 – 250 MW of natural gas combined cycle generation after 2020. Existing resources, recent and proposed additional renewables and cost-effective, bilateral

[9] Docket No. E015/M-12-920

market purchases will provide a stable, cost effective resource mix for a defined period between now and 2020 as a bridge to implementation of a natural gas resource.

Bi-lateral market purchases have a distinct role in meeting customers' energy needs between now and 2020 and are not a standing supply approach for the long term. Rather, they provide a particular opportunity for very economical, shorter term (2 to 5 year) energy supply given the low demand for power in the current wholesale energy market. Using stably priced, bilateral purchases with strong counterparties from existing assets for some shorter term supply helps mitigate rate impacts on Minnesota Power customers by deferring the addition of capital costs for a gas resource between now and 2020. They also allow for flexibility as large new customer loads ultimately materialize, given the wide range of load growth projections illustrated in Minnesota Power's 2012 Annual Forecast Report ("AFR2012"). As well, a more paced timing of adding a natural gas combined cycle resource will aid the development of the best natural gas project for Minnesota Power's customers.

Technological Evolution

Technology evolution in the energy industry is occurring rapidly. Advancements in detecting and extracting shale gas, for example, are impacting gas supply and moderating price volatility outlook. Additionally, advances in solar technology have resulted in a reduction in the cost of solar photovoltaic panels, making solar energy a more viable consideration for distributed generation portfolio expansion in the future. Minnesota Power's customers are best served by a resource strategy that is flexible and nimble to be able to help develop and capitalize on these technology developments at the right time. Advancing too soon creates unnecessary risk for customers and not being flexible to move soon enough can stymie creative and cost effective solutions as well. The most recent example of "right timing" with technology has been the way Minnesota Power advanced its wind development. This effort began first with smaller power purchase agreements and small self-build projects, stepping up to larger commitments as technology matured eventually leading to Minnesota Power's delivery of a very efficient and cost effective large wind generating portfolio in the North Dakota Bison projects.

Minnesota Power is steadily following and studying technology developments to determine if and to what extent the significant incorporation of new technologies in its plans to serve customers is appropriate.

Updates Since the Last Approved Minnesota Power Resource Plan

Specific actions taken since the May 2011 approval of Minnesota Power's 2010 Plan include:

1. Minnesota Power has acted to implement and procure the most appropriate sources to add to its renewable energy supply (see Appendix G). The Company has:

i. Commissioned the 81.9 MW Bison 1 Wind Project near Center, North Dakota[10] in December 2011.

ii. Received Commission approval and commissioned the 105 MW Bison 2 and Bison 3 Wind Projects[11] also located near Center, North Dakota before year end 2012.

2. In addition to the wind energy noted above, Minnesota Power has made, or is making, the following modifications to its supply side resources:

   i. Secured a 250 MW PPA with Manitoba Hydro to begin in 2020 which has been subsequently approved by the Commission.[12] This PPA requires a new, international transmission interconnection. Minnesota Power, in partnership with Manitoba Hydro, has initiated the Certificate of Need process for the Great Northern Transmission Line[13] that will facilitate delivery of the PPA energy and additional resources for the Upper Midwest. The agreements also provide for a unique wind storage provision that will allow Minnesota Power to effectively store excess wind energy from the Bison projects in North Dakota in Manitoba Hydro's hydro facilities. As well, the Midwest Independent System Operator, Inc. ("MISO") has recognized the Manitoba PPA will meet capacity eligibility standards.

   ii. Advanced an efficiency improvement rerunnering project at the Company's Fond du Lac hydroelectric facility, in partnership with the U.S. Department of Energy. The project is in final construction phase and is expected on-line in 2013. Additionally, the Company has restored the smaller, Prairie River hydroelectric facility near Coleraine, Minnesota which was destroyed by fire. It, too, is expected to be operational in 2013. Further, the Thomson Hydroelectric facility, flood damaged in 2012, is being engineered for restoration to service.

   iii. Requested Commission approval for the transfer of Rapids Energy Center ("REC") into Minnesota Power's regulated operations.[14] Additionally, Minnesota Power has requested Commission approval for an optimization project at REC that will increase biomass generation by approximately 56,000 MWh annually at a cost of approximately $10 million. At the same time, the Company has tabled plans for a biomass expansion at its Hibbard Renewable Energy Center ("HREC"), as more cost effective biomass and wind projects changed the priority of this project to beyond 2020.

[10] Docket No. E015/M-09-285
[11] Docket No. E015/M-11-234 and Docket No. E015/M-11-626, respectively
[12] Docket No. E015/M-11-938
[13] Docket No. E015/CN-12-1163
[14] Docket No. E015/M-12-1349

iv. Further reductions of Young 2 capacity from the current 227.5 MW level will occur upon Minnkota Power Cooperative, Inc. ("Minnkota") placing in-service its new Center to Grand Forks 345 kV transmission line in late 2013. As set forth in Docket E015/PA-09-526, the new line will trigger phase out of Young 2 from Minnesota Power supply resources entirely by 2026.

v. Finalizing key power purchase extensions in 2013 that leverage Minnesota Power's transmission assets and securing economic bilateral contracts to bridge Minnesota Power's customer supply requirements to the 2020 time period.

vi. Preparing to complete major environmental retrofits on BEC4 to address MATS, the Minnesota Mercury Emissions Reduction Act of 2006 ("MERA") and other new and existing state and federal emission control regulations.[15] Minnesota Power plans to begin BEC4 project construction in spring 2013, assuming receipt of permits, with in-service expected by 2016.

3. Minnesota Power continues its participation in the CapX2020[16] multi-state transmission reliability improvement initiative. Specifically, Minnesota Power is a participant in the Bemidji to Grand Rapids, Minnesota project; the Fargo, North Dakota to St. Cloud, Minnesota project; and the St. Cloud to Monticello, Minnesota project. The 230 kV Bemidji to Grand Rapids, Minnesota transmission line was energized on September 12, 2012.

4. Minnesota Power has remained a state leader in energy conservation and demand side management ("DSM"). (See Appendix B). Under its Conservation Improvement Program ("CIP"), Minnesota Power has met or exceeded the state's 1.5 percent energy savings goal by refining its conservation program strategy and expanding upon a proven program platform. In fact, Minnesota Power exceeded the energy savings goal, achieving a total savings of 1.8 percent of eligible retail energy sales for 2010, and 2.1 percent of eligible retail energy sales for 2011.[17]

Minnesota Power has a solid load research foundation and has initiated an updated load research study. This study is leveraging Minnesota Power's experience with its large customers' years of more sophisticated metering as well as the broader and more recent deployment of advanced metering infrastructure among residential and other customers along with insight gained through ongoing customer surveys.

[15] Docket No. E015/M-12-920
[16] CapX2020 is a joint initiative of 11 transmission-owning utilities in Minnesota and the surrounding region to expand the electric transmission grid to ensure continued reliable and affordable service.
[17] Minnesota Power will file its 2012 CIP Consolidated filing giving its 2012 results on April 1, 2013 and will be providing the Triennial Plan in June 1, 2013.

Minnesota Power continues development and implementation of its residential Time-of-Day Rate with critical peak pricing pilot project. The Commission approved Minnesota Power's proposed Pilot Rider for Residential Time-of-Service in November 2012.[18] The associated web portal that enables customers to view their usage information in monthly, daily, or hourly increments was introduced to two groups of customers in 2012, one in March and the next in August. This pilot builds upon Minnesota Power's existing conservation improvement effort and will offer further insight into customers' appetites for more frequent and in depth information about their energy usage as well as a rate offering with price signals.

Resource Plan Overview: Short and Long Term Action Plans

Minnesota Power considered potential environmental regulation and economic futures along with its sales outlook to develop a resource plan that creates a more flexible and diverse power supply, while balancing cost, reliability and environmental impact for customers. The 2013 Plan continues the transformation of the Company's resource base by investing in renewable generation, adding natural gas to its fuels portfolio, installing more emissions-control technology at its core, baseload generating facilities, and maintaining its strong energy conservation and demand side management programs. Supported by the information and analysis in the Appendices of this Plan, the action plan outlined in the following sections identifies both short and long term measures that will help Minnesota Power continue to meet customer needs near term and be poised to deliver safe and reliable service at the lowest possible cost to customers for many years.

Short-term Action Plan (2013 through 2017)

Minnesota Power's short-term action plan during the five-year period of 2013 through 2017 is comprised of steps that will: a) preserve competitive base load generating resources while reducing emissions, b) continue implementation of least cost demand side resources including conservation, c) reduce reliance on coal-fired generation, d) reduce the carbon intensity of Minnesota Power's system and e) add renewable energy and transmission infrastructure to the benefit of customers. The specific strategic and necessary actions to achieve these steps include:

1. Reducing emissions associated with converting coal energy to electricity through a series of actions that assures environmental compliance and a sound energy supply for customers. Minnesota Power has identified that LEC (110 MW) and THEC3 (75 MW) are not cost effective to retrofit with additional environmental controls. LEC will become a gas peaking station; THEC3 will be retired. The remaining balances of LEC and THEC3 will be recovered through normal retirement accounting (see Appendix L). The Company also has confirmed a robust plan to retrofit BEC4, its largest generating unit (585 MW).

[18] Docket No. E015/M-12-233

2. Minimize short-term rate impacts for customers while meeting increased demand for electricity, by taking advantage of a lower cost power market. Minnesota Power plans to use economic, asset backed bilateral market purchases to flexibly help bridge energy and capacity requirements in the period between 2014 and 2020. As well, Minnesota Power will continue to examine its load projections and adapt to the ultimate timing of new large industrial loads on its system as well as any significant downward business cycles that may affect demand from existing large industrial customers.

3. Continue optimization of Minnesota Power's renewable energy supply. With 400 MW of competitive wind projects already present in its portfolio, Minnesota Power is ahead of its renewable energy standard ("RES") requirements and is closely monitoring the need for additional intermittent renewable energy. With the extension of the PTC, Minnesota Power will solicit a request for proposal for a minimum of 100 MW and up to 200 MW of competitive wind to be installed in the next two to three years. These plans are subject to maximizing the benefit of the PTC for customers.

4. Consider enhancements to selected CIP and DSM programs, while continuing to apply best practices from the conservation industry and develop leading-edge programs. Minnesota Power has maintained a strong record of conservation performance and been a state leader in meeting and exceeding the Minnesota 1.5 percent energy savings conservation standard. Along with this strong dedication to conservation, Minnesota Power will continue to work to identify reasonable additions to its DSM programs where they are most beneficial for customers.

5. Prepare Minnesota Power's transmission system for the longer term addition of new power supply resources. The Company will, subject to Commission approval, begin implementation of the Great Northern Transmission Line to deliver its approved 250 MW energy purchase from Manitoba Hydro for the period 2020-2034, a key element of Minnesota Power's long-term action plan. The Certificate of Need application for the Line will be filed in 2013 as part of project development.

6. Complete its 2013 Load Research Study Advanced Metering Infrastructure Project to better understand customer energy use, providing a refreshed and robust basis for future customer conservation projects and sound rate design.

7. Execute an industrial distributed generation/renewable project at REC and continue to explore energy efficient distributed generation projects with large customers. Additionally, Minnesota Power will develop a fair, equitable and customer focused distributed generation approach that best leverages unique customer and regional attributes to deliver valued and cost effective energy solutions for customers.

8. Continue fleet maintenance programs to sustain the economic viability, availability and reliability of Minnesota Power's generating units. A continuing Company priority throughout this planning period will be to carefully maintain

its generation fleet to ensure productivity and efficiency in operation. A rigorous process is in place to sustain existing production across Minnesota Power's wind-water-wood-coal energy conversion facilities while maintaining an excellent environmental record, working through an orderly workforce transition and meeting more stringent environmental standards.

9. Continue participation in the Midwest Renewable Energy Tracking System ("M-RETS") as provide for by the Commission's October 9, 2007 Order,[19] as well as establishing a program and protocols for tradable, renewable energy credits.[20] Minnesota Power will leverage the value of renewable energy credits that the M-RETS program certifies to deliver RES compliance in Minnesota at the lowest possible cost to customers. Minnesota Power will utilize renewable energy credits generated across the years in order to optimally meet the 25 percent RES by 2025.

Long-Term Plan (2017 through 2027)

Minnesota Power will focus its long-term plan on a strategy to further reduce carbon emissions in its portfolio and reshape its generation mix towards a balance of approximately one-third renewable resources, one-third efficient coal-fired generation and one-third natural gas/other sources. This long-term strategy will continue resource diversification and position Minnesota Power to be able to successfully adapt to a range of economic and environmental futures while maintaining service to its customers at a competitive cost. Each component of this long-term plan has been proven through the planning process analysis to be flexible and robust to keep progress toward the Company's strategic resource goals on track in a variety of future scenarios. Planned components include:

1. Continue implementation of the 250 MW Manitoba Hydro PPA and associated transmission in the 2020 timeframe.

2. Optimize the timing of implementing the remaining renewable projects to cost effectively meet the state RES by 2025.

3. Investigate opportunities to further diversify Minnesota Power's power supply including, further reducing reliance on coal-based generation. Minnesota Power will continue to closely assess THEC1&2 economics during this period to determine these units' competitive position.

4. Begin investigation, for inclusion in its next resource plan, of an intermediate natural gas generation resource for Minnesota Power's generation fleet to meet expected capacity and energy needs in the 2020 timeframe and beyond.

[19] Docket No. E999/CI-04-1616
[20] Docket Nos. E999/CI-04-1616 and E999/CI-03-869

Plan Implementation Potential Impact on Costs

In accordance with Minn. Rule 7843.0400, subp, 4, Minnesota Power's 2013 resource planning analysis includes consideration of potential cost impacts resulting from actions taken to be in compliance with Minnesota's RES, and potential expansion plans. The 2013 Plan's preferred plan ("Preferred Plan") would be expected to increase the average residential rate by about 4.4 percent on a compounded annual basis through 2017. That is equivalent to a total increase of $19.65 per month above the 2013 estimated Base Rate. The impact to the average Large Power rate would be an increase of about 3.7 percent on a compounded annual basis through 2017. That is equivalent to an increase of 1.09 cents per kWh above the 2013 estimated base rate. Refer to Appendix J for more detail.

Summary: 2013 Plan Designed to Meet Customer Needs

As Minnesota Power addresses uncertainty in the economic and environmental landscape around energy matters on behalf of its customers, the Company maintains its strong leadership of the transformation required to successfully meet future needs. In order to achieve the goals outlined on page 5 of this Section, Minnesota Power respectfully requests Commission approval of its 2013 Plan, as presented in this filing, for the planning period of 2013 through 2027. Minnesota Power is requesting Commission approval of its action plan that includes the following:

- Cease coal energy conversion at the 75 MW THEC3 and refuel the 110 MW LEC with natural gas, with both actions completed in 2015.
- Optimize Minnesota Power's renewable energy supply by evaluating the addition of a minimum of 100 MW and up to 200 MW of competitive wind that would be installed in the next two to three years, with plans subject to maximizing the benefit of the PTC for customers.
- Begin investigation, for inclusion in its next resource plan, of an intermediate natural gas generation resource for Minnesota Power's customers to meet expected capacity and energy needs in the post 2020 timeframe. Bridging to implementation of an intermediate gas unit, Minnesota Power will use bilateral market purchases to flexibly and economically help meet needs in the period between 2014 and 2020, as the Company continues to review load projections and adapts to the ultimate timing of new large industrial loads on its system.

Minnesota Power believes its 2013 Plan will serve its customers in a wise and forward-looking way during the 2013–2027 planning period. Minnesota Power respectfully submits this Plan for the Commission's review and approval.

III. Current Outlook

The electric industry landscape has continued to evolve since Minnesota Power's 2010 Plan. As well, the Company took action to further improve its fleet environmental performance, monitor and assess emerging regulations and increase renewable energy output. As this 2013 Plan is submitted, Minnesota Power is a very unique utility in the present dampened national economic outlook as significant growth is being projected for its large industrial customer segment in the current planning horizon.

This section identifies the major items contributing to Minnesota Power's outlook for customer demand for electricity and the supply resources that will be utilized as the foundation ("Base Case") for this resource plan. Minnesota Power starts this 2013 Plan planning period with minimal near-term power supply needs; however, due to projected customer growth, Minnesota Power will need additional power supply in the long term; post 2020.

Changes since May 2011 Commission Approval of the 2010 Plan

Continued Progress on Renewable Energy Standard

The 2007 Minnesota Legislature enacted legislation requiring Minnesota Power generate or procure increasing renewable energy supplies based on total retail sales to Minnesota customers beginning with 7 percent by 2010 and incrementally increasing to 25 percent by 2025 (Minn. Statute § 216B.1691).

Since May 2011, Minnesota Power has brought extraordinary benefit to its customers with its renewable energy development. Through effective project planning and competitive equipment supply, Minnesota Power has executed its North Dakota wind initiative plan introduced in 2009, including the recent commissioning of over 200 MW of additional wind through the Bison 2 and Bison 3 Wind Projects in 2012, and the continued operation of its Bison 1 Wind facility.

Further, the Bison wind initiative provides a unique opportunity to expand renewable resources in North Dakota by securing additional wind development land options and designing associated facilities in preparation for future wind energy projects. The development, planning and timing of these projects will be based on customer growth, availability of economical wind energy and the impact of this intermittent generation on Minnesota Power's system. Minnesota Power is ahead of the state's 25 percent by 2025 requirement and will only propose adding new wind projects if they are economical and bring benefit to customers. Appendix G provides a more detailed presentation of the current renewable portfolio that Minnesota Power plans to utilize to meet its renewable requirement.

Rapids Energy Center

Minnesota Power submitted its petition for approval of a biomass energy optimization project for its industrial distributed operation facility in Grand Rapids, Minnesota on December 19, 2012.[21] The REC optimization project will increase biomass generation by approximately 56,000 MWh annually.

Corporate Commitment to Greenhouse Gas Reductions

Minnesota Power continues its commitment to taking action to reduce carbon emissions. Fundamental to this initiative is a significant expansion of Minnesota Power's already substantial renewable energy supply, its commitment to improve efficiency and to consider only carbon-minimizing resources for addition to its generation portfolio. These actions are leading to a transformation of Minnesota Power's generating fleet. Increasing amounts of energy will be supplied by renewable resources or natural gas resulting in less reliance on coal-fired energy.

Demand Response and Conservation—Energy Reduction Requirements

The 2007 Minnesota Legislature enacted legislation requiring utilities to adopt an annual energy savings goal equivalent to 1.5 percent of gross annual retail energy sales beginning in 2010. Minnesota Power has a successful track record in meeting the 1.5 percent benchmark and plans to maintain conservation efforts at this level.[22] Minnesota Power is evaluating an air conditioning cycling program and how this type of program may fit into its future power supply planning. Appendix B addresses Minnesota Power's DSM and current conservation efforts.

Move to MISO Module E Planning Year 4

As a result of tariff revisions in 2008 by MISO, Minnesota Power now falls under the requirements of the MISO Module E Resource Adequacy Program for near-term planning. Each year MISO produces a new planning reserve requirement for its footprint. For 2012, Minnesota Power was required to meet a non-coincident peak reserve margin of 11.32 percent. This 2012 reserve requirement was a reduction from the 2011 reserve requirement of 12.04 percent. This savings has resulted in more capacity being available to serve customer requirements.[23]

Softening of Energy Market

Since 2009, the nationwide recession and the onset of natural gas supply surpluses have created a significant shift in the regional energy markets. Prices have shifted lower to create a new normal for markets unparalleled in recent history.

[21] Docket No. E015/M-12-1349
[22] Minnesota Power incorporates the effects of its successful conservation program into its energy forecast. Appendix A outlines this methodology in more detail.
[23] Minnesota Power has requested that MISO provide a non-coincident reserve margin for its 2013 Loss of Load Expectation update to allow for continued incorporation of MISO's system reliability studies into Minnesota Power's long-term planning process.

Minnesota Power has worked to secure extensions of existing key bilateral purchase contracts for energy and capacity totaling 150 MW[24] during the 2015-2020 timeframe.

Evaluating the options for an economical power supply to meet the projected growth in northeastern Minnesota, 100 MW[25] of additional short-term bilateral purchase transactions were initiated to capture the benefit of the lower market trends for customers and bridge to the approved 250 MW power purchase from Manitoba Hydro that starts in the 2020 time period. In addition to providing a cost effective bridge to Minnesota Power's long-term resource strategy, these transactions also help customers avoid costly generation expense as new large industrial loads transition onto the system.

Certified Interruptible Demand ("CID") Anticipated to be 96 MW

Minnesota Power has continued offering its interruptible product that permits the curtailment of large industrial load to support Minnesota Power's management of system reliability. Interruptible capability continues to be a robust demand response resource for customers. Based on current indications from the industrial customers who have used these products, Minnesota Power is planning on the new CID product creating the availability of 96 MW of interruptible demand as of June 2013.

Specific Load Additions

Since 2009, several potential industrial load additions have been closely monitored in Minnesota Power's and its wholesale customers' service territories. Essar Steel Minnesota, a significant new customer for the City of Nashwauk, Minnesota, has been incorporated into Minnesota Power's 15 year forecast outlook as Minnesota Power serves the City of Nashwauk, a valued municipal customer. This is reflected in the Base Case of this resource plan. Minnesota Power is utilizing the Wholesale Industrial Customer Addition scenario of its AFR2012 for the Base Case of its planning evaluation.

Minnesota Power will continue to monitor the status of the load potential in northeast Minnesota and has incorporated a high and low forecast as sensitivities in its evaluation. Appendix A goes into more detail on the other customer load scenarios that Minnesota Power is monitoring.

Current Outlook for Large Power and Resale Customers

Recognizing that the majority of Minnesota Power's capacity and energy is used by 10 Large Power customers, it is important to monitor the current outlook of these customers to provide insight into their future electric needs.

[24] These transactions include the current 50 MW **[TRADE SECRET DATA EXCISED]** contracts. Minnesota Power will be seeking in 2013 regulatory approval of transactions that span five years or greater once terms are finalized.

[25] These market surplus transactions include the current 50 MW **[TRADE SECRET DATA EXCISED] [TRADE SECRET DATA EXCISED]** agreements.

Minnesota Power recognizes that not all projected growth in its industrial customer class will be forthcoming exactly on its proposed schedule. Through its econometric forecasting processes and by working closely with customers, Minnesota Power identified and included with its AFR2012 forecast submittal four scenarios for this growth potential and their impact to electric requirements in its service. For the 2013 Plan, the Wholesale Industrial Customer Addition scenario is utilized, recognizing 166 MW of overall industrial growth for this 15-year time period.

Following are current industry summaries and load potential that Minnesota Power is tracking for its largest industrial customers:

Mining Customers

Minnesota Power provides electric service to six taconite customers with current production capability up to 41 million tons of taconite pellets annually (see Table 1). Taconite pellets produced in Minnesota are primarily shipped to North American steel making facilities that are part of the integrated steel industry. Steel produced from these North American facilities is used primarily in the manufacture of automobiles, appliances, pipe and tube products for the gas and oil industry, and in the construction industry. Historically, less than five percent of Minnesota taconite production is exported outside of North America.

Minnesota Power Taconite Customer Production

Year	Tons (Millions)
2012	39 (est.)
2011	39
2010	35
2009	17
2008	39
2007	38
2006	39
2005	40
2004	39
2003	34

Table 1--Minnesota Power Taconite Customer Production

The 2008-2009 recession notwithstanding, Minnesota taconite production has been very near capacity for the past ten years. Domestic demand and production for the traditional taconite product has been very steady.

- As well, newer types of iron-bearing products have emerged and are being produced on the Iron Range. Further, the potential for steelmaking on the Iron Range also exists. All together the combination of new iron ore based projects or expansions indicates growth forecast for mining and mining processing activity. Mesabi Nugget Delaware, LLC, a partnership of Steel Dynamics Incorporated and Kobe Steel, began production of iron nuggets in 2009. This 500,000 metric ton per year prototype iron nugget facility has added over 20 MW of demand to the Minnesota Power system. Mesabi

Nugget is continuing with permitting activities relating to an expansion of the facilities to allow for its own taconite mining to produce concentrate to feed the nugget facility. This could more than double the facility load within the next five years.

- Magnetation, Inc. is a high-growth iron ore producer and inventor of hematite beneficiation technology. Magnetation has developed a patented mineral reclamation process (Magnetation Process™) to extract weakly magnetic particles from stockpiles left from the natural ore mining that occurred primarily in the first half of the Twentieth Century. Magnetation currently operates two facilities in Minnesota: Plant 1 located south of Keewatin; and Plant 2 near Taconite. Minnesota Power recently filed a petition with the Commission to amend its contract with Magnetation to reflect increased service extension costs resulting from an anticipated load increase of 3 to 5 MW as a result of an expansion to Plant 2 that will begin in spring 2013. Magnetation is also an equity partner in the Mining Resources Plant 3 facility near Chisholm. Mining Resources Plant 3 is producing at nearly their budgeted full load level. They activated their ball mill circuit in January 2013 and peak demands are now in the 5 to 7 MW range. Additionally, Magnetation LLC has announced that it will build two more facilities similar to Plant 2 in the coming years. Magnetation's contemplated Plant 4 facility will be sited north of Coleraine near the Canisteo Mine and is slated to come on line in late 2014. The other facility site is just south of the town of Calumet. It is tentatively planned to come online in 2015. Minnesota Power currently provides electric service to the Plant 2 facility as well as to the Jesse Mine train loading facility and Minnesota Power will also provide service to the Plant 4 and 5 facilities.
- Mining Resources, LLC is an 80-20 joint venture between Steel Dynamics, Inc. and Magnetation, Inc. Mining Resources will utilize the Magnetation beneficiation technology in Plant 3 located to the south of Chisholm. The concentrate for this facility supplies the Mesabi Nugget plant in Hoyt Lakes until such a time as Mesabi Nugget is able to obtain permits to mine and produce its own concentrate from the former LTV mining company holdings.
- Essar Steel is developing a fully integrated, onsite, mining through steelmaking project on the Mesabi Range in northern Minnesota. It is designed to produce up to 2.5 million tons of steel products each year and to employ up to 700 people. Groundbreaking occurred in fall 2008 for the taconite production facility. Construction activities are well underway for the initial 4.1 million ton per year taconite plant, and the permits have been finalized for the expansion to a 6.5 million ton per year taconite production rate. Essar continues to work on the financing for the 6.5 million ton per year operation. Mining operations are slated to start in 2013. Minnesota Power provides wholesale electric service to the City of Nashwauk who in turn provides retail electric service to the Essar mine, crusher, concentrator, and pellet plant. Minnesota Power also provides retail service to Essar at two points for pit dewatering.

- Keewatin Taconite is wholly owned by United States Steel ("USS") Corporation. In February 2008, USS Corporation announced its intent to restart a pellet line at its Keewatin Taconite processing facility ("Keetac"). If restarted, this pellet line, which has been idle since 1980, could bring 3.6 million tons of additional pellet making capability to northeastern Minnesota and could result in over 60 MW of additional load. USS Corporation announced in late January 2013 that the project is on hold while the Company looks at business conditions, and some proposed regulatory standards that would be relevant to the project.

In addition to robust growth projections in ferrous mining, exploration and permitting work continue on several other fronts for future development of non-ferrous resources located in the Duluth Complex geologic formation. PolyMet mining is in its permitting processes, and Minnesota Power has entered into a long-term power supply agreement with PolyMet. Additionally, business cases are being developed for Twin Metals Minnesota and Teck America, as well as for other prospective customers.

Wood Product Customers

Minnesota Power serves four paper and pulp customers who produce market pulp and various grades of printing and writing paper used in office papers, magazines, catalogs, and print advertising/direct mail. The North American paper manufacturing industry has experienced a significant decline in the last decade resulting in mill consolidation and closures throughout North America. Minnesota has directly experienced forest product-related mill closures. Six Minnesota mills have closed since 2006 including three Ainsworth board mills, the Weyerhaeuser truss plant in Deerwood, the Verso paper mill in Sartell, and the Georgia Pacific board plant in Duluth. Minnesota Power provided electric service to the Deerwood and Duluth mills.

As shown in Figure 1 below, U.S. printing and writing paper demand is projected to continue to decline, although at a less precipitous rate than during the 2007-2009 period. This decline in demand for printing and writing paper is driven by electronic media substitution and the associated migration of advertising budgets away from catalogs, newspaper inserts, brochures and direct mail.

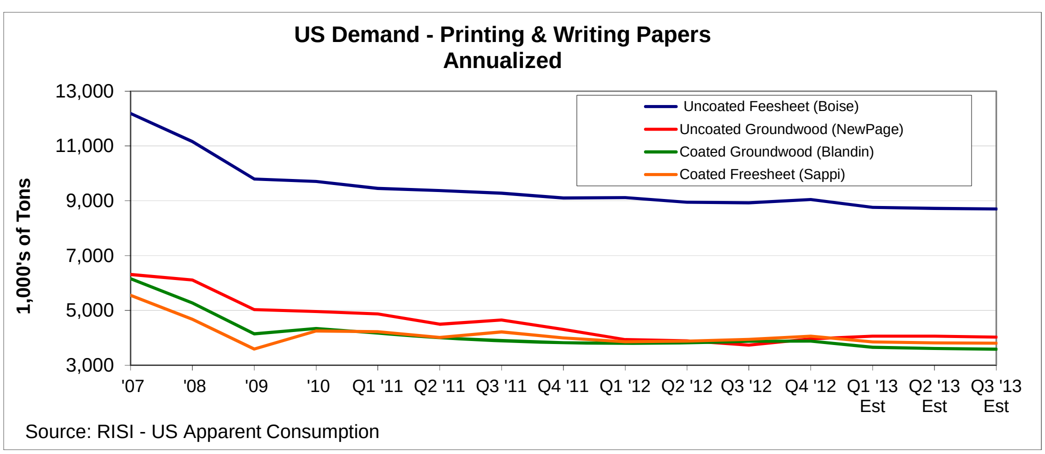


Figure 1--US Paper Demand 2007-2013 (est.)

In spite of the demand trends for US printing and writing paper, the remaining US paper industry continues to profitably operate at over 20 million tons of productive and competitive capacity and pursue development of new wood-related products. The most cost competitive mills with the strongest parent corporations continue to effectively serve their customers.

The four paper mills served by Minnesota Power, representing approximately 1.5 million tons of paper production, are owned by well-established and major paper industry leaders (Sappi, UPM, NewPage, and Boise). As reflected in this resource plan, Minnesota Power believes these corporations view their Minnesota assets as strategic to their respective business strategies. Each of the Minnesota mills is well positioned and cost-competitive in their respective paper markets with excellent customer relationships. Minnesota Power projects steady and profitable capacity utilization rates for these four mills over the forecast period as these mills successfully control costs, reshape their products and compete for market share.

Pipeline Customers

Minnesota Power has two pipeline customers, Enbridge Energy and Minnesota Pipeline. Both companies rely heavily on Western Canadian crude oil production. Enbridge Energy transports crude oil across North America. Minnesota Pipeline receives oil from Enbridge Energy at Clearbrook, Minnesota, and delivers it to refining centers in the Twin Cities metro area. A significant oil discovery in northern Alberta (“Oil Sands”) in the early 1990s has led to increased throughputs on both the Enbridge Energy and Minnesota Pipeline systems. At the same time, shale oil production in North Dakota has also been increasing rapidly. Oil Sands and North Dakota shale crude production is forecast to increase significantly over today’s levels over the next few years, which will prompt the need for increased transport capacity on the Enbridge Energy and Minnesota Pipeline systems.

Both Enbridge Energy and Minnesota Pipeline take service under Minnesota Power’s Large Light and Power Service Schedule (”LLP Schedule”). Neither Enbridge Energy nor Minnesota Pipeline is now required to provide Minnesota Power with demand nominations under the LLP Schedule; however, these loads have historically been very consistent. Enbridge Energy is adding pumping equipment at its Superior, Wisconsin pumping station (served by Minnesota Power’s affiliate and wholesale customer, Superior Water, Light & Power) and Enbridge has increased pumping capacity at its Deer River, Minnesota substation, with significant projected increases in load through 2017. Other expansion-related projects are in the planning phase at these companies and could potentially further increase load across the Minnesota Power service territory within a five to ten-year horizon.

Expected Minnesota Power Load and Capability

Northeastern Minnesota’s economy underwent a severe downturn in the recent national recession. Both peak demand and energy use dropped considerably in late 2008, but quickly rebounded in 2010 led by the region’s taconite and wood products industries. Core sectors – residential, commercial and industrial – have recovered most of the ground lost during the recession, and growth is expected throughout the long-term planning horizon.

For the 2013 Plan, the load outlook includes a projection for considerable growth over the fifteen-year period. In particular, Minnesota Power is expecting significant industrial customer expansion. With several growth scenarios incorporated into its latest forecast outlook, Minnesota Power has identified the Wholesale Industrial Customer Addition scenario as its consensus outlook for its 2013 Plan. Appendix A contains details on Minnesota Power's AFR2012.

Minnesota Power is historically a winter peaking utility and, based on monthly trends in load behavior, is expected to remain winter peaking for the AFR forecast period of 2012 to 2026. Throughout the forecast time-frame, the seasonal peaks run in parallel. Underlying seasonal peak demand growth is projected to increase at a rate consistent with observed history, about 0.7 percent per year. However, load growth in the 2013 to 2014 timeframe will be accelerated as the Company realizes expansions in its industrial customer base. Annual load growth is projected to average 4 percent per year in 2013 and 2014.

Figure 2 presents both Minnesota Power's historic and forecast peak demand from the Wholesale Industrial Customer Addition scenario in its AFR2012 submittal and the foundation for the 2013 Plan evaluation. The graph depicts the significant growth being projected in the forecast period.

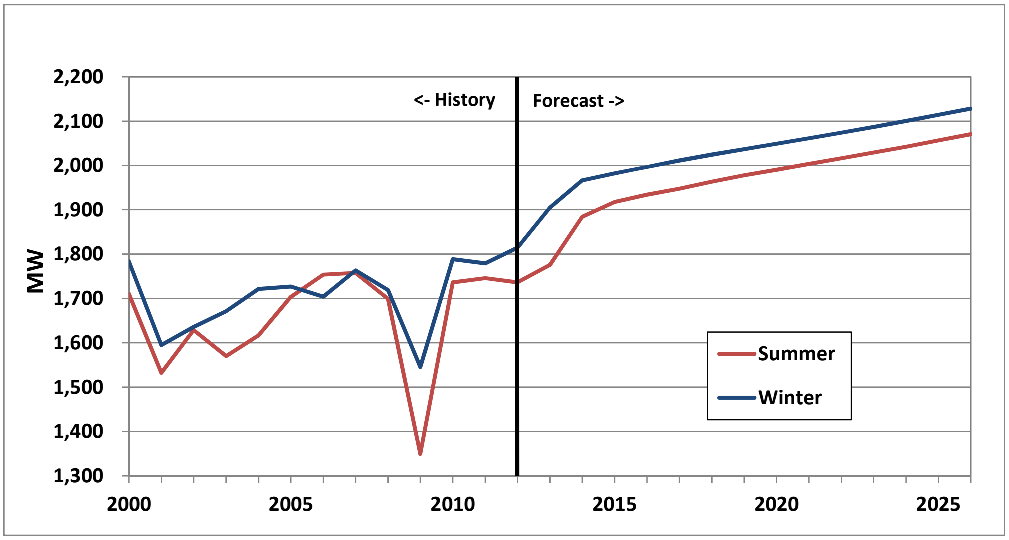


Figure 2--Peak Demand by Season

Figure 3 shows historic and forecast energy requirements by customer class and depicts the large influence the industrial class continues to have on Minnesota Power's energy requirements. The large growth in the Resale customer class includes the addition of the City of Nashwauk load as described above.

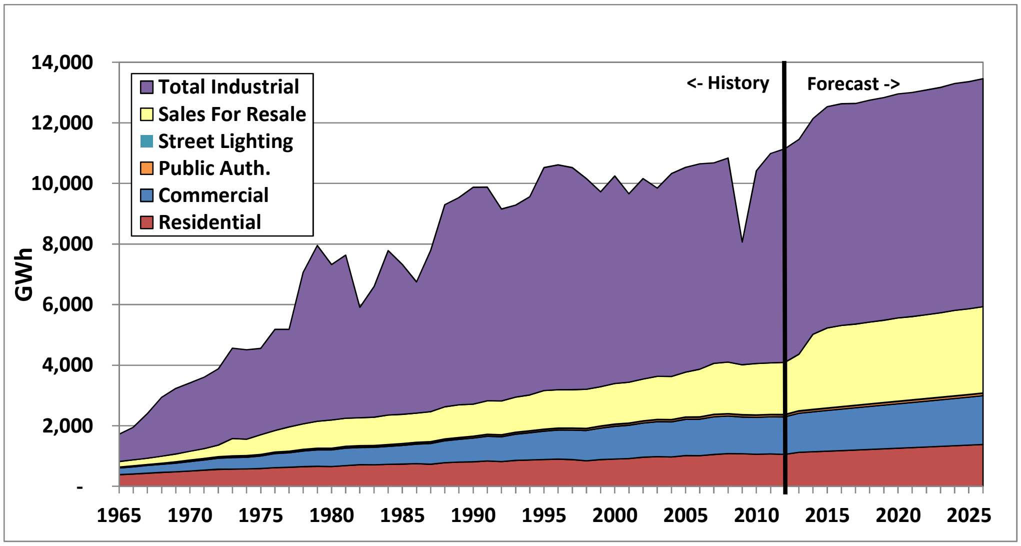


Figure 3--Energy by Customer Class

Taken together, Figure 2 and Figure 3 clearly show the expected future growth and the impact of the 2009 recession. As outlined in the AFR2012, Minnesota Power's peak demand and energy use are each expected to grow quickly in the near-term with several industrial additions and are then projected to return to more normal growth levels for the long term.

Minnesota Power's system load forecast reflects a projected (summer) peak demand of 1,918 MW by 2015 and 2,070 MW by 2026. While Minnesota Power's load growth can be unpredictable due to industrial changes, about a 0.7 percent underlying demand growth is projected through the forecast period. Energy requirements continue to dominate Minnesota Power's supply picture, as the industrial load contributes to an average Minnesota Power system load factor of approximately 80 percent—still one of the highest in the nation.

Minnesota Power uses the 2012 MISO Module E Load and Capability ("L&C") calculation as one measure to assess resource need. The MISO L&C calculation takes into consideration Minnesota Power's load forecast, expected demand-side resources, Firm and Participation Purchases and Sales, Accredited Installed Generating Capability and MISO's required 11.3 percent planning reserves. The result of the L&C calculation is a capacity surplus (or deficit) number for each planning season.[26] Minnesota Power is a winter peaking utility, but, as previously noted, bases its resource need on the summer season L&C balance. Most other regional utilities are summer peaking and, accordingly, have large winter capacity surpluses. Therefore, winter capacity is typically available for purchase, and prices are expected to be lower than summer capacity.

Minnesota Power utilizes the Wholesale Industrial Customer Addition scenario from its AFR2012 in its 2013 planning analysis. To create an understanding of what the

[26] Minnesota Power does not utilize MISO's UCAP (unforced capacity) planning reserve method for its long-term planning; rather, it relies on the ICAP (installed capability) that is more appropriate for long-term evaluations. Please see Appendix H for more detail.

potential capacity needs are under this outlook, the load levels of the scenario are combined with an expected set of capacity resources utilizing the L&C guidelines noted above to estimate a remaining surplus or deficit for the planning period. Figure 4 depicts the Base Case summer season capacity needs that are projected as Minnesota Power considers its 2013 Plan resource planning analysis. For the near term (pre 2020), Minnesota Power expects some minimal capacity surpluses in its Base Case outlook, with capacity need starting to grow in the post-2020 time period.

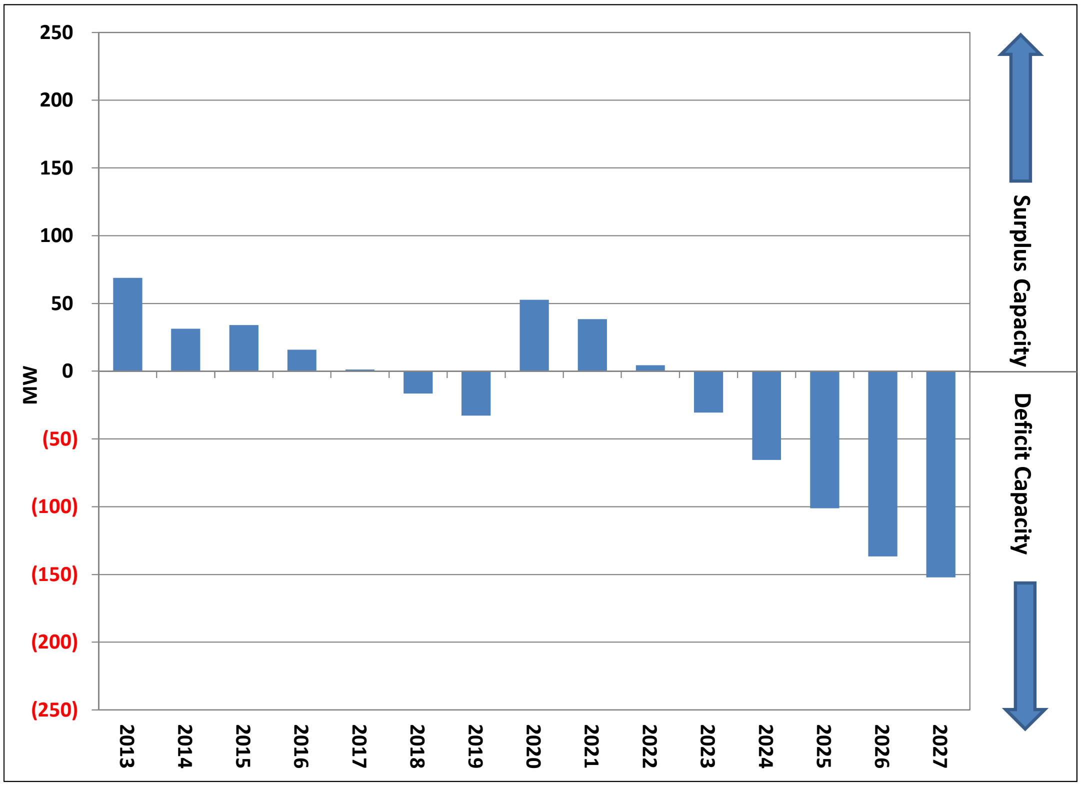


Figure 4--Projected Summer Season Capacity Position

Base Case:

Minnesota Power's Summer and Winter Season Load and Capability (2013–2027)

Figures 5 and 6 present Minnesota Power's Base Case load and capability for summer and winter seasons, respectively, during the forecast period. Key assumptions and events reflected in the Base Case load and capability projections include:

1. No permanent large industrial customer plant closures are projected during the forecast period (see Appendix A). Growth in the industrial customer class brings 166 MW of additional requirements by the end of the planning period.
2. Continuing commitment to conservation initiatives throughout the forecast period resulting in achieving at or near the currently filed level of 1.6 percent annual retail energy savings. Load reductions from Minnesota Power's conservation efforts are included as reductions in Minnesota Power's projected load (see Appendix A).

3. Through the North Dakota initiative, a phased reduction of the Minnesota Power 227 MW portion of the Young 2 coal resource will occur starting in 2014 and conclude in 2026.
4. Operating renewable resource additions required to meet Minnesota's RES including: Taconite Ridge, Wing River and Bison 1, 2 and 3 wind projects are added to the fleet (see Appendix G).
5. Implementation of the 250 MW Manitoba Hydro power purchase starting in 2020.
6. Estimated accredited capacity associated with remaining planned renewable additions per Minnesota Power's renewable mandate strategy are not included in the capability as committed resources because final timing is yet to be determined such as additional wind at the Bison location in North Dakota and additional biomass energy at the REC and HREC (see Appendix G).
7. Minnesota Power continues its large industrial customer generation partnerships for distributed generation and behind the meter generation purchases.
8. Existing wholesale power sales and purchase changes (see Appendix C).
    - Base load power sale of 100 MW (2010-2020)
    - Extension of 150 MW of key bilateral purchase contracts (2015-2020)
    - Inclusion of 100 MW of economic market surplus bilateral purchase contracts (2015-2020)
9. CID is estimated to be 96 MW for the planning period. This reflects changes in contractual requirements of the existing interruptible service commitments for the large industrial class and a changed future market environment.
10. No retirements of Minnesota Power's thermal or hydro generation resources are included in the Base Case outlook depicted in this section. Within this 2013 Plan is an evaluation of Minnesota Power's small thermal coal-fired generation to determine an environmental compliance strategy for MATS regulation. This Base Case is the starting point for that evaluation.

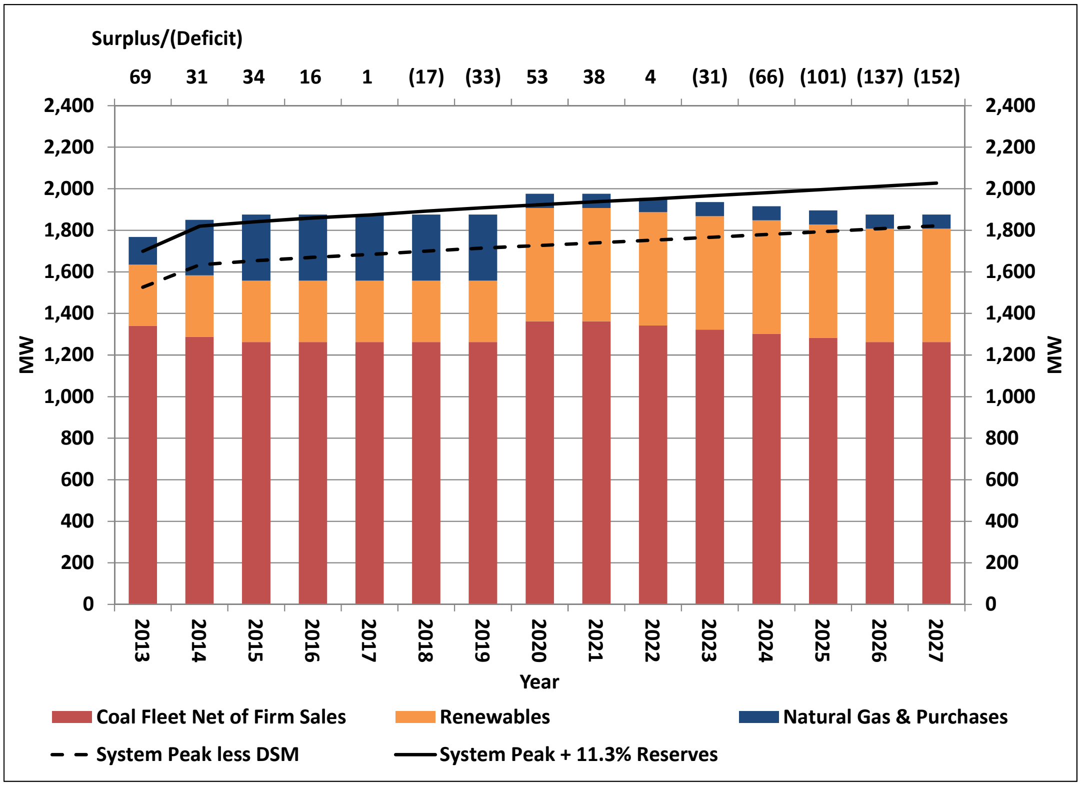


Figure 5--Base Case Summer Season Load and Capability

Minnesota Power's winter peak is typically close to 60 MW higher than its summer season peak; therefore, the surplus and deficit outlook is slightly different when shown for the winter season peaks. The general trends remain the same with very little deficit in the near term and growing long-term needs for capacity.

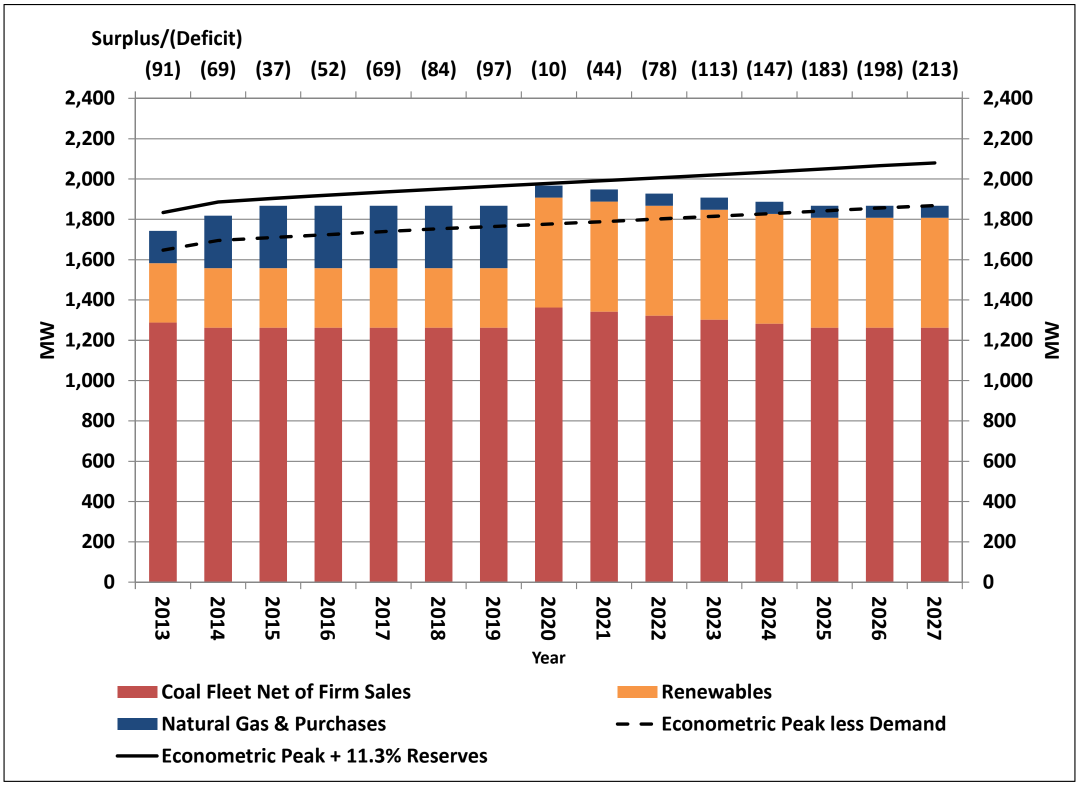


Figure 6--Base Case Winter Load and Capability

Minnesota Power has positioned its resources, including its existing generation (thermal and renewable) along with economic purchases, to meet the projected needs of its customers in the near term and create a bridge to longer-term additions like the Great Northern Transmission Line and accompanying Manitoba Hydro power purchase. The 2013 Plan evaluation identifies how Minnesota Power will implement a power supply strategy to meet any remaining needs after consideration of small thermal coal-fired generation decision making and projected customer growth.

The Base Case energy position is shown in Figure 7, identifying that, in the near term, Minnesota Power has minimal energy needs and will use the regional wholesale market to optimize its energy supply for customers in keeping with its least cost strategy.

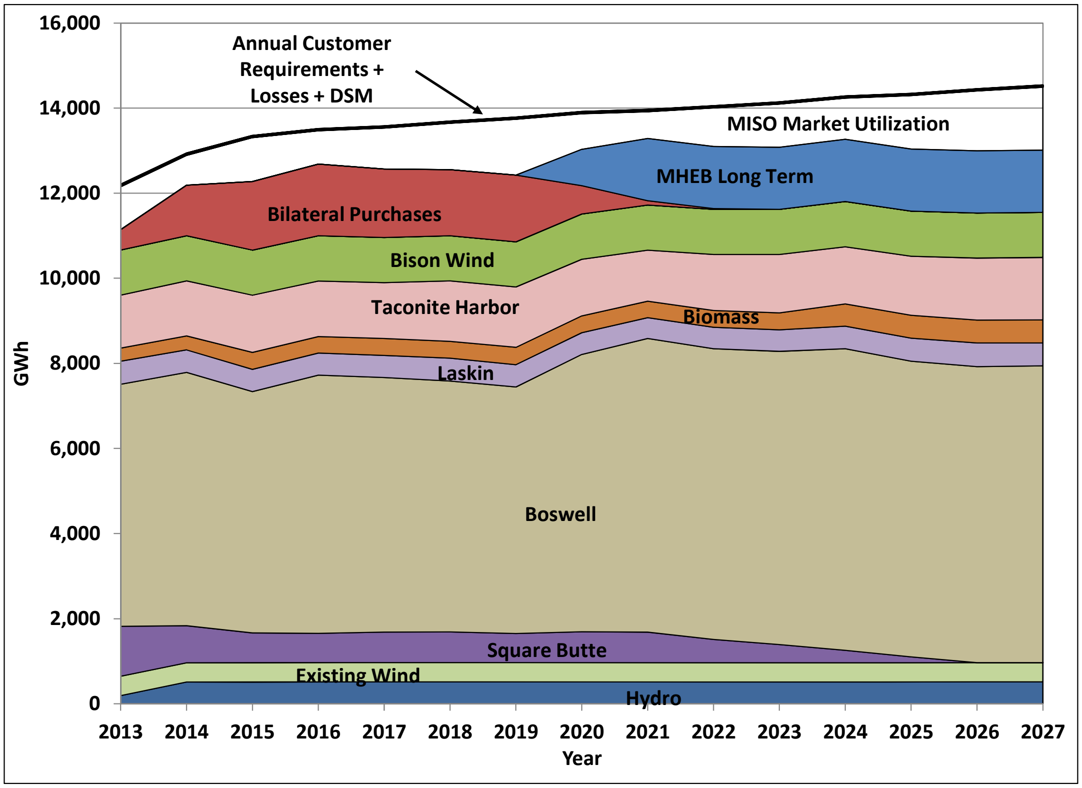


Figure 7--Base Case Energy Position

The regional market allows Minnesota Power to maximize its generation and transactions. In particular, the market provides timely and cost effective flexibility to help support the integration of additional renewable energy into Minnesota Power's system. The maturity of and flexibility within the regional energy market allows Minnesota Power to buy and sell electricity to manage supply and demand for the topmost portion of its load at the lowest possible cost.

High and Low Sensitivities for Demand and Energy

To capture the plausible ranges of uncertainty in Minnesota Power's customer outlooks, three additional sensitivities were chosen for further examination from the AFR2012: the Moderate Industrial Expansion, High Industrial Expansion and Low Economic and Industrial forecasts. These outlooks, shown in Figures 8 and 9, were used to determine contingencies for Minnesota Power's short- and long-term action plans and recognize the range of uncertainty that exists with Minnesota Power's unique customer base.

The Moderate and High Industrial Expansion outlooks contemplate significant growth in the mining industry, capturing up to 600 MW of growth potential in a high economic boom in the industrial sector. The Low Economic and Industrial forecast evaluates a slowdown in the key industries Minnesota Power serves along with a continued sluggish U.S. economy that could deliver up to 200 MW of demand destruction in Northeast Minnesota. Appendix A contains additional detail on each scenario.

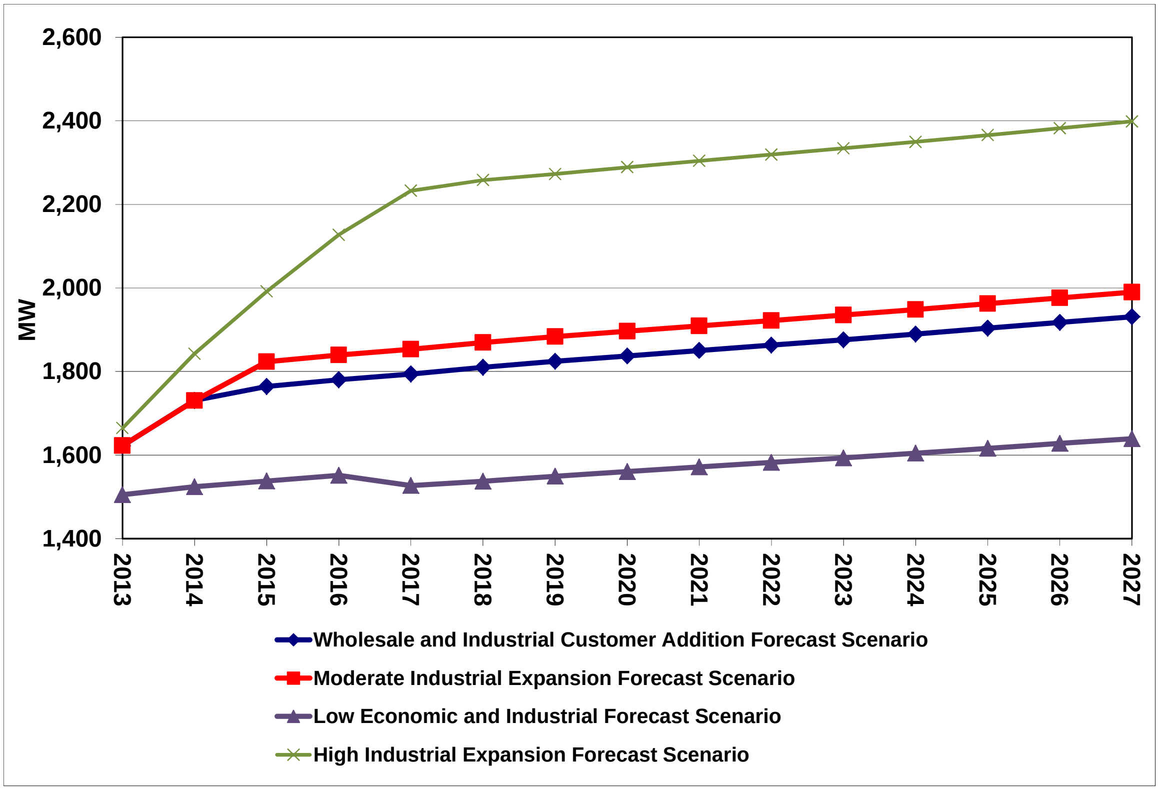


Figure 8--High and Low Demand Outlook Sensitivities

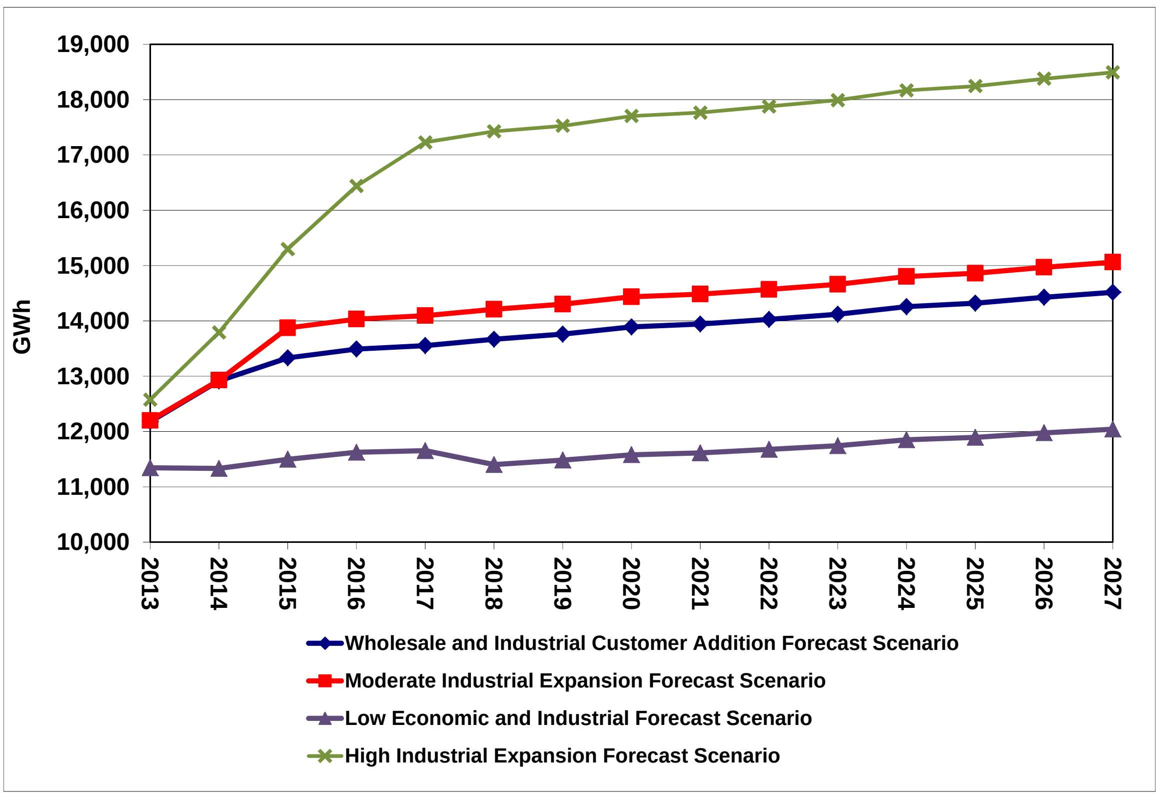


Figure 9--High and Low Energy Outlook Sensitivities

Minnesota Power continually monitors the potential for industrial growth in Northeastern Minnesota and recognizes the key role the mining and paper industries play in its customer make-up, system needs and system costs. The viability of these customers is the engine that helps drive the northeastern Minnesota economy. Making prudent and reasonable power supply plans for meeting future electric needs for industry and all other customers is critical in helping to keep economic balance in place to best serve all customers.

IV. 2013 Plan Development

Minnesota Power's 2013 Plan is focused on a balanced approach to delivering safe, reliable service at the lowest possible cost to customers while protecting and improving the region and state's quality of life through continued environmental stewardship. Since its baseload diversification study, Minnesota Power has refined and updated its outlook on major factors driving its power supply decisions and identified specific environmental compliance options that are viable at its coal-fired facilities. Building upon insights gained during the analysis completed over the past several months, the 2013 Plan documents how Minnesota Power utilized its planning process to develop a path toward reducing emissions, protecting reliability, and ensuring cost-effective rates for its customers.

Evaluation Framework

Minnesota Power faces two key long-term planning questions in this fifteen-year planning period. First, what environmental compliance strategies will be utilized to keep its coal-fired generation in compliance with the recently finalized MATS regulations, and second, how will it position and augment its power supply to meet the load growth potential that is emerging in its service territory. Minnesota Power recognizes the continued uncertainty of other federal environmental regulations as described in Appendix E and must plan accordingly to take appropriate actions. The 2013 Plan takes into consideration Minnesota Power's expected levels of additional regulations and projected customer power supply needs, and identifies the Preferred Plan as the least cost and most reasonable for this planning period.

Minnesota Power has worked through a transparent and iterative process with its stakeholders to identify the alternatives and considerations for environmental compliance at its coal-fired generation fleet. Starting with its 2010 Plan, Minnesota Power identified key themes of power supply diversification and environmental pressure on its coal-fired generating facilities. The February 2012 Baseload Diversification Report framed the high level cost ranges for Minnesota Power's coal-fired generating facilities to meet a wide range of potential outcomes for air, water and waste regulations being contemplated at the federal level. As more information and certainty with the final MATS Rule became known in December 2011, Minnesota Power was able to continue the process of designing and evaluating detailed alternatives for its coal-fired generation facilities. Using engineering and site specific detail, Minnesota Power determined specific quantifiable and actionable options for each alternative available during Plan development.

As shown in Figure10 below, the Baseload Diversification Report identified key trends of pending environmental regulations and their potential impact on Minnesota Power's generation fleet. Additionally, the knowledge gained from the baseload diversification study prepared Minnesota Power to proceed toward more detailed consideration of the three main alternatives available for meeting environmental compliance requirements of the final MATS Rule: "Retrofit," "Remission," and "Closure." Each of these alternatives has facility specific characteristics that must be taken into consideration. The 2013 Plan addresses each of Minnesota Power's facilities impacted by the MATS regulation and identifies how Minnesota Power determined the best compliance path for serving its customer power supply.

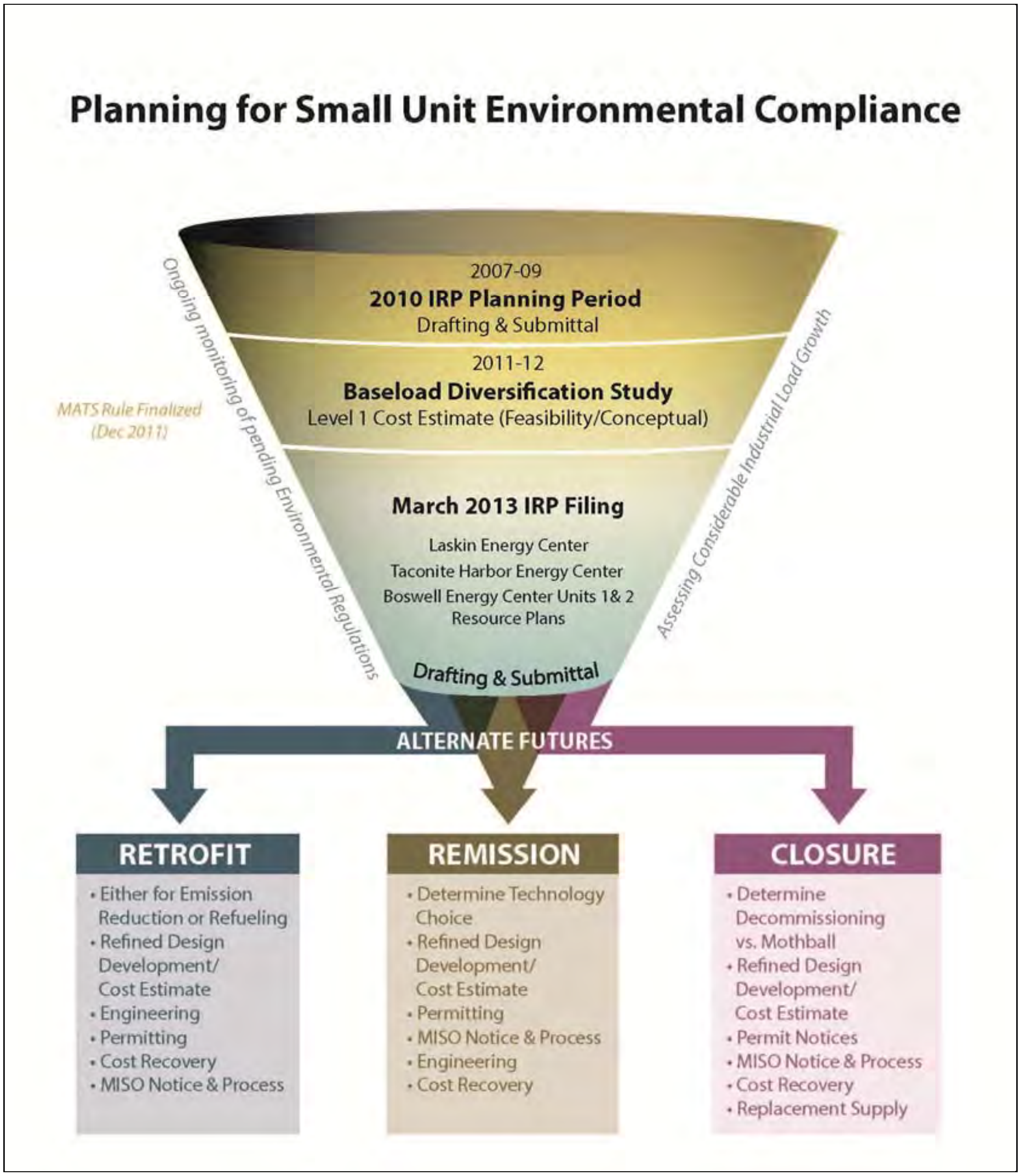


Figure 10--Planning for Small Unit Environmental Compliance

To advance the evaluation of Minnesota Power's coal-fired fleet to the next level and prepare for the 2013 Plan, several items were updated and refined from the Baseload Diversification Report. These items include:

a) Environmental Regulation Outlooks (see Appendix E) - Minnesota Power evaluated the status and certainty around the ten environmental regulations it monitors on an ongoing basis and determined which rules would be part of its Base Case evaluation and those that would be considered in an EPA sensitivity for the purposes of the 2013 Plan. In general, the Coal Ash Residuals and Steam Effluent Guidelines still contain sufficient uncertainty where inclusion in the Base Case is not appropriate until more detail is determined. Therefore, these uncertainties were considered in an EPA sensitivity.

b) Environmental Retrofit and Remission alternatives were refined to be specific to each Minnesota Power facility to gain necessary insight to cost estimates for decision-making.

c) Generation revenue requirements were updated with the latest information on ongoing capital and operating expenses at each facility.

d) Minnesota Power's capacity resources were updated to include the latest in near-term bilateral contracts and accredited capacity values.

e) Industry Outlooks (see Appendix H) - Minnesota Power assembled the latest industry data for generation technology, natural gas, coal, and other key power supply drivers and trends to ensure an up-to-date set of assumption data was available.

f) Minnesota Power's energy demand outlook was updated with AFR2012, its latest submittal to the Department of Commerce – Division of Energy Resources ("Department").

Together, the items above were considered in the 2013 Plan evaluation to a level appropriate for establishing a power supply strategy and determining Minnesota Power's short and long term action plans.

Utilities plan in an uncertain business environment recognizing not all assumptions will become reality. The resource planning process in Minnesota is dynamic and allows additional information to be gathered, applied, and resource strategy adjustments to be incorporated in the best interests of the customers on an ongoing basis.

For the 2013 Plan, a four step planning evaluation was used to arrive at the environmental compliance strategy for each facility and to find the best resource alternatives to augment Minnesota Power's supply for long-term customer requirements. Minnesota Power created its Preferred Plan by first determining its actions needed to comply with the MATS Rule on its coal-fired generation facilities (Preferred Coal Plan) and then augmenting this with the expansion plan that best serves customer needs over the planning period. The four sequential steps include:

1. "MATS Compliance" – Determine if a retrofit or remission alternative is most cost-effective for each coal-fired facility to meet the MATS Rule.

2. "Shutdown Consideration"– Determine if the generation facility should be closed/shutdown rather than move forward with the cost effective retrofit or remission option from Step 1.

   These first two steps will define Minnesota Power's Preferred Coal Plan.

3. "Identifying the Preferred Plan"– Identify a resource expansion plan that will augment the environmental compliance strategy identified in Steps 1 and 2 (Preferred Coal Plan) to best meet customer requirements over the study period.

4. "Comparative Analysis" – Compare and stress Minnesota Power's Preferred Plan against three other viable alternatives in a swim lane[27] analysis.

   a. The three other swim lane alternatives include these action plans:

      i. Retrofit all Minnesota Power's coal-fired facilities with needed emission reducing technology to meet the MATS Rule.

      ii. Close Minnesota Power's LEC and THEC generating facilities.

      iii. Evaluate adding the closure of THEC1 and THEC2 to Minnesota Power's Preferred Plan.

   b. Comparison of the three swim lane alternatives include a series of 21 sensitivities that stress the key power supply cost drivers such as fuel, capital and additional customer load outlooks (see Appendix I).

To begin to understand Step 1 and Step 2 in this evaluation (see Figure 11), Minnesota Power has, through the 'Coal-Fired Generation Considerations' section on page 38, identified for each of its coal-fired generation facilities impacted by the MATS Rule, the site specific alternatives available and gives insight to how it made the decision to retrofit, remission or close the generation facility.

[27] A swim lane is a mechanism to evaluate alternatives by considering them in a side-by-side "lane." For the 2013 Plan, each lane contains an alternative path for Minnesota Power's supply options.

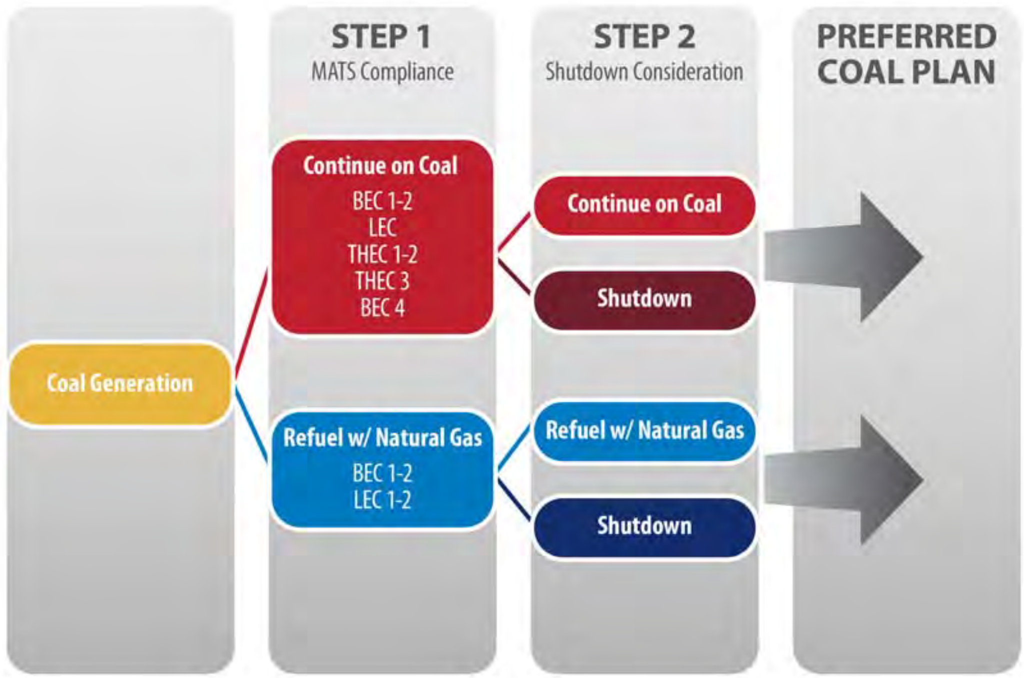


Figure 11--Plan Development Process - Steps 1 and 2

The ‘Expansion Planning for New Generation Resources’ section beginning on page 55 will share the results from Step 3 that determines which resources should augment Minnesota Power’s supply portfolio. Finally, Step 4, the comparison of the three swim lane alternatives, will be discussed in the ‘Analysis and Insights’ section and will demonstrate how the Preferred Plan will bring cost and environmental benefits to customers’ electric supply. Steps 3 and 4 are shown in Figure 12.

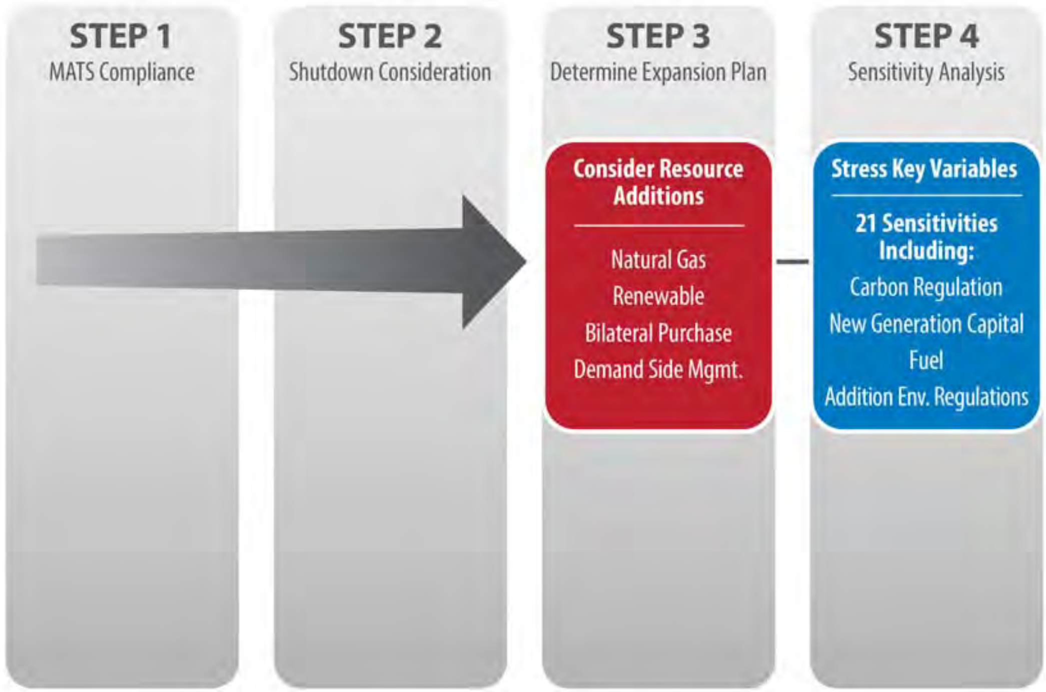


Figure 12--Plan Development Process - Steps 3 and 4

Coal-Fired Generation Considerations

Minnesota Power's LEC in Hoyt Lakes, Minn., THEC near Schroeder, Minnesota and BEC in Cohasset, Minnesota are each impacted by the finalization of the MATS Rule. Additional state requirements exist for BEC3 and BEC4 under MERA. For each of its coal-fired facilities Minnesota Power identified and considered detailed alternatives for retrofit, remission and closure to meet finalized MATS requirements. This section, with support from Appendix C and Appendix E, will describe the drivers of the environmental compliance strategies that Minnesota Power is moving forward with in its 2013 short and long-term action plan (see Sections V and VI).

Boswell Energy Center

Minnesota Power's largest coal-fired facility has just over 1,000 MW and a shared infrastructure that supports the operation of four generating units. BEC3 (365 MW) and BEC4 (585 MW of which Minnesota Power has an 80 percent ownership share), are the largest units of BEC, producing over 5.8 million MWh annually for customers (over one-third of the Company's power supply). The two smaller units, BEC1&2, combine for a total of approximately 140 MW and provide vital restoration capability during startup operations and facility-wide support. Operating at baseload levels, BEC provided nearly half of the energy that Minnesota Power generated to meet customer requirements in 2012. BEC employs about 200 full-time Minnesota Power employees.

Substantial investments have been made at the BEC facility for environmental and efficiency related improvements over the past several years, with the largest investment in BEC3. As explained in more detail in Appendix E, BEC3 underwent a significant multi-pollutant environmental retrofit completed in 2009 for controlling sulfur dioxide (“SO_2), oxides of nitrogen (“NO_x), particulate matter (“PM”) and mercury. The controls put in place on BEC3 reduced air emissions by 90 percent or more for the four effluents, below prescribed MATS levels, and BEC3 will not require any additional technology investment to remain environmentally compliant with the MATS Rule and MERA.

BEC4, Minnesota Power’s largest baseload generating resource, is slated for an extensive environmental retrofit from 2013 to 2015 to address mercury, trace metals and PM to meet requirements of MERA and the MATS Rule. Minnesota Power completed a careful evaluation and engineering for mercury reduction alternatives over the past several years[28] to begin preparing for the MERA requirements. With the finalization of the MATS Rule in late 2011 and confirmation that the multi-pollutant retrofit alternative Minnesota Power was evaluating for MERA would also meet the finalized MATS Rule, Minnesota Power moved forward on the BEC4 retrofit. In August 2012, Minnesota Power requested approval from the Commission of its BEC4 Project,[29] proposing an environmental retrofit was the most reasonable and least-cost, environmentally compliant strategy for Minnesota Power customers. Minnesota Power’s Baseload Diversification Report and the Department’s comments in that Docket further supported the decision to move forward with an environmental retrofit on BEC4. Initial Department analysis determined that, at the expected level of environmental compliance costs, retiring BEC4 is not a cost-effective option. BEC4 joint owner, WPPI Energy,[30] requested and gained approval for the BEC4 Project from the Public Service Commission of Wisconsin.[31] The BEC4 Project is included as part of Minnesota Power’s 2013 Plan for all four swim lane alternatives.

BEC1&2 are also well positioned for upcoming MATS requirements and for continuation as valuable resources in Minnesota Power’s customer supply. BEC1&2 operate with emission control equipment including low NO_x burners and fabric filters to control particulates and substantial mercury capture co-benefits. In 2008 and 2009, Units 2 and 1, respectively, were retrofitted with Mobotec Rotating Opposed Fired Air and ROTAMix emission control systems to further reduce the NO_x emissions from these

[28] Minnesota Power filed Mercury Emission Reduction Reports with the Commission in 2011 and 2012 (see Docket No. E015/M-11-712 and Docket No. E015/M-12-734).
[29] Docket No. E015/M-12-920
[30] See Docket No. E015/PA-90-153.
[31] The Public Service Commission of Wisconsin (“PSCW“) docket number for the WPPI Energy. Certificate of Authority filing is: PSCW Docket No. 6685-CE-110. The PSCW issued its written Certificate of Authority order for WPPI Energy’s participation in the BEC4 environmental retrofit project on February 11, 2013.

units. Fabric filter operation co-benefits at BEC1&2, plus the mercury reductions being realized at BEC3 and BEC4 (post retrofit), will allow the entire BEC facility to achieve compliance with the MATS Rule with no additional technology installations, as well as position the facility long term.

As part of the outcome of the baseload diversification study the commission requested further evaluation of BEC1&2 and that Minnesota Power include in its 2013 IRP:

> *"An evaluation of the consequences – including all relevant costs and the consequences for transmission adequacy – of retiring Boswell Energy Center, Units 1 and 2 by 2020."*

It is important to recognize the integration of BEC1&2 with the overall BEC facility when considering its potential closure. As mentioned above, the BEC units are not stand alone in such a way they can easily be separated; they share infrastructure, ancillary services and fuel handling with the rest of BEC. Specifically, BEC1&2 provide support to BEC3 and BEC4 during start up procedures, ongoing operations,[32] and during critical system restoration activities for Minnesota Power. When considering a closure of these two units it is necessary and appropriate to include the replacement cost of a 37 MW generating resource at the site to facilitate the continued operations of BEC. In its retirement evaluation, Minnesota Power included a 37 MW reciprocating engine project into the closure scenario to account for energy replacement and the ability to participate in the system restoration plans for the BEC facility. Site-wide operational costs would need to continue if BEC1&2 were shut down, including an average $1.7 million in capital cost annually and $3 million in operation and maintenance ("O&M") cost annually. These costs include common equipment and services that will need to continue for power production to occur at BEC if BEC1&2 were shutdown. This would effectively increase the operations cost for the remaining units. Minnesota Power included the necessary costs for the BEC1&2 shutdown scenario that was analyzed to ensure BEC3 and BEC4 would have the operational support needed.

No concerns were identified in screening the transmission considerations of shutting down BEC1&2. Due to its location in Cohasset, Minnesota with robust transmission system interconnections with the rest of the regional network, no transmission concerns were identified. However, if a shutdown were to be needed, Minnesota Power would enter into the appropriate Attachment Y process with MISO to secure official confirmation about impact from its regional transmission operator.

A refuel of the BEC1&2 boilers to natural gas was also an alternative considered for meeting the Commission Order point above. Before conducting the shutdown evaluation, Minnesota Power compared the existing BEC1&2 resources with a natural gas refuel option. The refuel conversion would entail inserting natural gas burners into

[32] BEC1&2 provide compressed air, service water and intake cooling water to the large BEC facility. The electrical and communication infrastructure of BEC1&2 is also closely intertied with BEC3.

the current boilers and allowing them to fire completely on natural gas as a fuel source. This would maintain full capacity benefit for customers and serve as a peaking energy resource to protect customers from high regional market prices. To help meet the start-up time requirements for BEC1&2 on natural gas, steam needs to be routed from BEC3 to the BEC1&2 turbines to keep the turbines warm and ready for start-up.[33] The refuel option also allows BEC1&2 to continue to operate as part of the larger BEC facility infrastructure and meet system restoration requirements. BEC has natural gas supply infrastructure in place, including appropriately sized pipe that could accommodate the operation of BEC1&2 on natural gas; minimal common infrastructure would need to be added to implement the refuel. The estimated capital cost of a natural gas refuel for BEC1&2 is $14 million (see Appendix M).

Figure 13 below identifies BEC1&2 as resources that run a large part of the year, or at high capacity factors of 70 to 80 percent.[34] If BEC1&2 are converted to natural gas and continue to run at the same high capacity factor level (shaded area in graph below), the cost is higher than if BEC1&2 were kept as coal-fired generators.[35] The graphic also identifies that if BEC1&2 were running less than 40 percent of the time, then the natural gas refuel option could have benefit. It is evident that the existing BEC1&2 resources are the lowest cost options for customer power supply when comparing costs of the existing unit to the costs with a natural gas refuel option.

[33] The steam needed for a BEC1&2 start-up on natural gas is taken into account by reducing the output at BEC3 by 14 MW when considering the refuel alternative.
[34] Based on operations data over the past six-year period.
[35] A capacity factor represents how much of the year a generator resource runs in comparison to its nameplate capacity. Minnesota Power's coal-fired fleet runs at higher capacity factors to serve the high energy needs of its customers and provide low cost energy all hours. Peaking natural gas resources typically run at low capacity factors (less than 20 percent on average).

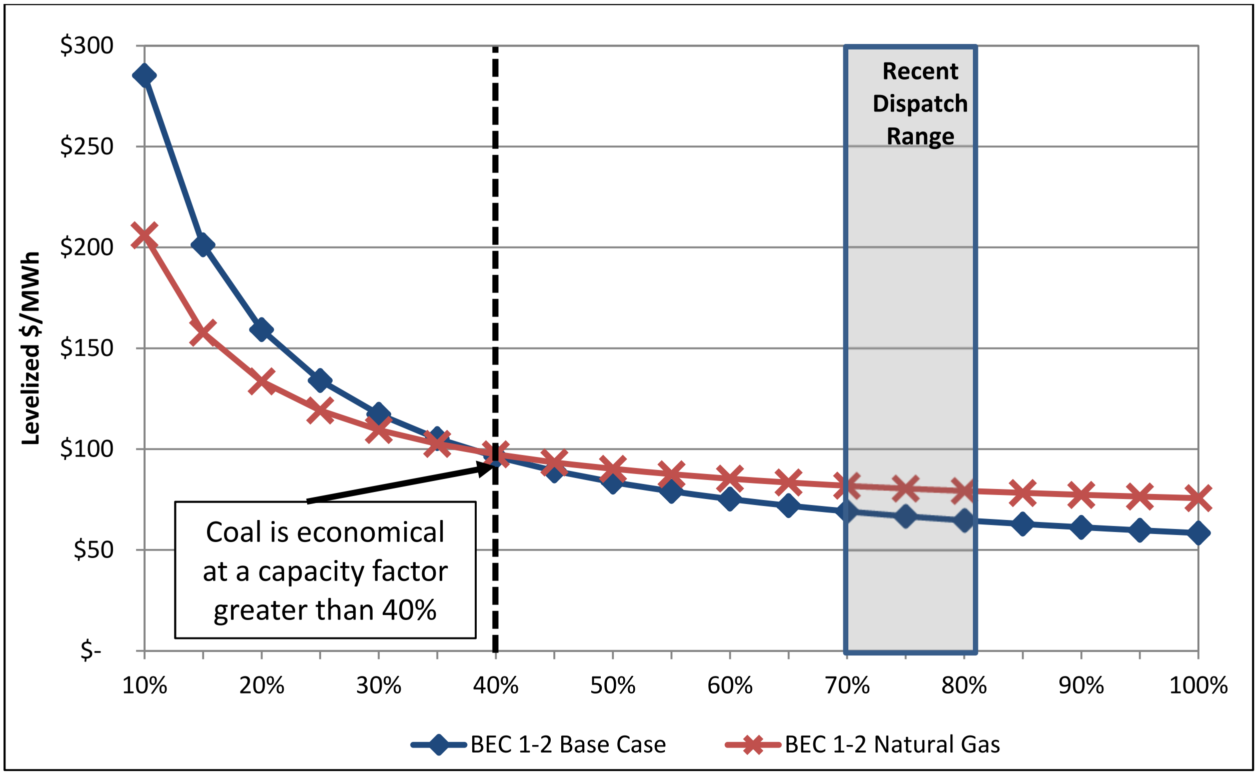


Figure 13--BEC1&2 Levelized Product Cost at Varying Capacity Factors

Figure 13 should be considered in context. It is a limited comparison of the two options and does not consider the remaining power supply resources. When the natural gas refuel and existing operation options are evaluated through a full production cost analysis of Minnesota Power's system in the Strategist software, BEC1&2 as a coal-fired facility continues to be the lowest cost option for customers under 1) Minnesota Power's base assumptions (as defined in Appendix H) with about $90 million of benefit, and 2) a greenhouse carbon regulation penalty scenario with about $70 million of benefit. The carbon regulation penalty scenario placed additional costs on existing generating sources that emit carbon dioxide ("CO_2") starting in 2017 with $21.50/ton.[36] In both outlooks, keeping BEC1&2 as environmentally compliant coal-fired generators serving baseload operations continues to have cost benefits for customers when compared to converting to natural gas for meeting the MATS requirements (see Table 2).

[36] Minnesota Power ran the greenhouse gas scenario as required by the Commission's Orders implementing Minn. Stat. § 216H.06 to consider carbon regulation penalties that hypothetically occur beginning in 2017. Minnesota Power has concerns that utilizing carbon regulation penalties other than predetermined externality values until a valid penalty structure is implemented or designed may be detrimental to customers. Appendix E gives more insight to this perspective.

Table 2--BEC1&2 Power Supply Cost Comparison for MATS Solution

Strategist Power Supply Cost 2013-2034 NPV ($ Millions)	BEC1&2 Coal	BEC1&2 Natural Gas Refuel	Customer Impact (Gas Refuel – Coal)
Base Assumptions	$8,147	$8,237	$91
With CO_2 Regulation Penalty $21.50/Ton in 2017)	$9,750	$9,819	$70

Step 2 or the "Shutdown Evaluation" indicated that customers would not benefit from a retirement of BEC1&2; in fact, it would be unnecessarily costly to retire these two units. The evaluation included the optimization of a BEC1&2 retirement option with the rest of the system alongside new generating resource alternatives. When the option to retire BEC1&2 was given to the system wide optimization evaluation in the Strategist Proview software, it identified that BEC1&2 remain viable power supply resources as environmentally compliant coal-fired generation; the retirement option was not economically beneficial for customers (see Appendix I).

Minnesota Power identified through the BEC1&2 closure evaluation that at this time, with current environmental regulations and no greenhouse gas regulation in place, there are no driving factors to close these two resources. BEC1&2 will best serve customers through their continued operation providing economic capacity and energy. Minnesota Power will continue to monitor industry, environmental and system conditions that impact BEC1&2 and all of its resources. Through its ongoing resource planning process, Minnesota Power will communicate with stakeholders as power supply action plans evolve for BEC1&2.

Laskin Energy Center

LEC has been evaluated over the past year to determine the specific environmental compliance options available to allow the facility to meet the finalized MATS Rule. The Commission requested as part of the outcome of the baseload diversification study further evaluation of LEC and that Minnesota Power include in its 2013 IRP:

> *"A proposal to address the viability of Laskin Energy Center, Units 1 and 2, and Taconite Harbor Energy Center, Unit 3."*

This section will describe Minnesota Power's consideration of environmental compliance alternatives and the viability for LEC, supporting the decision that refueling the two generating units to natural gas in 2015 is in the best interest of customers.

Each LEC unit operates with a generation capability of 60 MW gross (55 MW net) with about 5 MW of existing station service steam per unit to operate auxiliary equipment. Originally known as the Aurora Steam Station, the facility was commissioned in 1953 with a total station capability of 88 MW and was designed to serve the needs of an expanding taconite industry. Both units were uprated to the present capability (110 MW) in 1967 through boiler, control system, turbine, and generator upgrades. In 1971, the units were retrofitted with full particulate wet scrubbers, among the first full-scale scrubbers in the U.S., and converted to utilize low-sulfur western fuels. A second stage of scrubber enhancements was later added to improve efficient particulate removal. The infrastructure has been well maintained and the two units share electric and heating infrastructure with a single control room for operations. The units have maintained a 50 to 60 percent capacity factor over the past six years as market and operating conditions have changed, providing an average of 518,000 MWh for customers each year. The facility is in close proximity to one of the major natural gas pipelines in the region, Northern Natural, and utilizes natural gas as a starting fuel for its current coal-fired operations.

From an environmental control perspective these units are well controlled. The units have two-stage wet particulate scrubbers for PM, SO_2 and co-benefit mercury removal. As a part of Minnesota Power's Arrowhead Regional Emissions Abatement ("AREA") Plan, LEC received significant investment beginning in 2006 through 2008, with the installation of low NO_x burners and over-fire air systems to reduce the NO_x emissions by 66 percent. The MATS Rule would require that LEC install additional boiler injection technology to further reduce mercury emissions to meet required thresholds. Other alternatives for environmental compliance with the MATS Rule include a natural gas refuel or closure of the facility.

The injection technology option would introduce sorbents into the LEC boilers and, through active management with the other environmental control systems in the plant, keep mercury and other hazardous air pollutants below required MATS thresholds. The active sorbent that would be utilized in the process is considered a variable cost and would fluctuate with the production of electricity. Minnesota Power identified through an engineering evaluation that the cost to install an injection system into the two boilers at LEC would be approximately $6 million in capital expense and would increase variable costs by approximately $1.50 per MWh for the needed sorbents to control mercury.

The refuel conversion option would place natural gas burners into the current boilers and allow them to fire completely on natural gas as a fuel source rather than coal. The conversion would maintain the full capacity benefit of approximately 110 MW for customers at a reasonable cost and serve as a peaking energy resource to protect customers from high regional market prices. A peaking resource would run considerably less than the current LEC operation as coal-fired generation; typically a gas peaking resource will run less than a 20 percent capacity factor each year. However, even though the unit does not run continuously, the value is in the protection it provides to customers against high regional power prices and provided capacity. Energy supply would be optimized between LEC and the regional power market on a real-time basis, taking the least cost power supply for customers.

Natural gas is an environmentally cleaner combustion process, so emissions would be reduced overall through an LEC conversion to natural gas. Greenhouse gas would be reduced, as coal is no longer the fuel source utilized. A LEC conversion to natural gas would reduce CO_2 by 1,075 pounds per MWh. In addition, SO_2, mercury, lead and PM would be reduced by over 90 percent and NO_x would be reduced by approximately 50 percent from current emission levels, bringing significant environmental benefit to the region. Minnesota Power identified that to refuel LEC to natural gas would require an estimated $14 million in capital expense[37] and would significantly decrease O&M costs. The facility would require about one-third of the current staff and maintenance requirements would decrease with natural gas-fired operations in comparison to coal. The natural gas fuel supply would be available from an adjacent high pressure regional pipeline. A fuel procurement strategy would be put into place before 2015 to ensure fuel supply is available. LEC is already serviced by a gas supply making this option beneficial to customers as Minnesota Power is able to optimize the fuel procurement for LEC.[38]

The first step in the LEC evaluation was to compare the environmental compliance options of injection technology and the refuel to natural gas before considering a shutdown alternative for the facility. LEC has been maintaining 50 to 60 percent capacity factors for the past 6 years. When the generation costs are compared one-to-one, the natural gas refuel and injection technology implementation costs are extremely close. Figure 14 below identifies that at a 55 percent capacity factor, the two compliance options are essentially equal. As the capacity factor of LEC is decreased, the natural gas refuel option is the lower-cost option for customers. Since LEC would face additional economic pressure with injection technology from where it is operating today due to increased costs, it is likely that capacity factors would decrease from today's level. If LEC were to reduce its capacity factor, it would essentially be operating more like an intermediate or peaking resource than a baseload unit; the natural gas refuel would be more economical for customers.

[37] This capital expense includes necessary natural gas fuel infrastructure to meet the requirements of the 110 MW generating capability. The natural gas procurement and strategies would be developed closer to the implementation date.
[38] The high pressure line is located less than one mile from LEC and an existing line into the facility will be upgraded to accommodate its new mission.

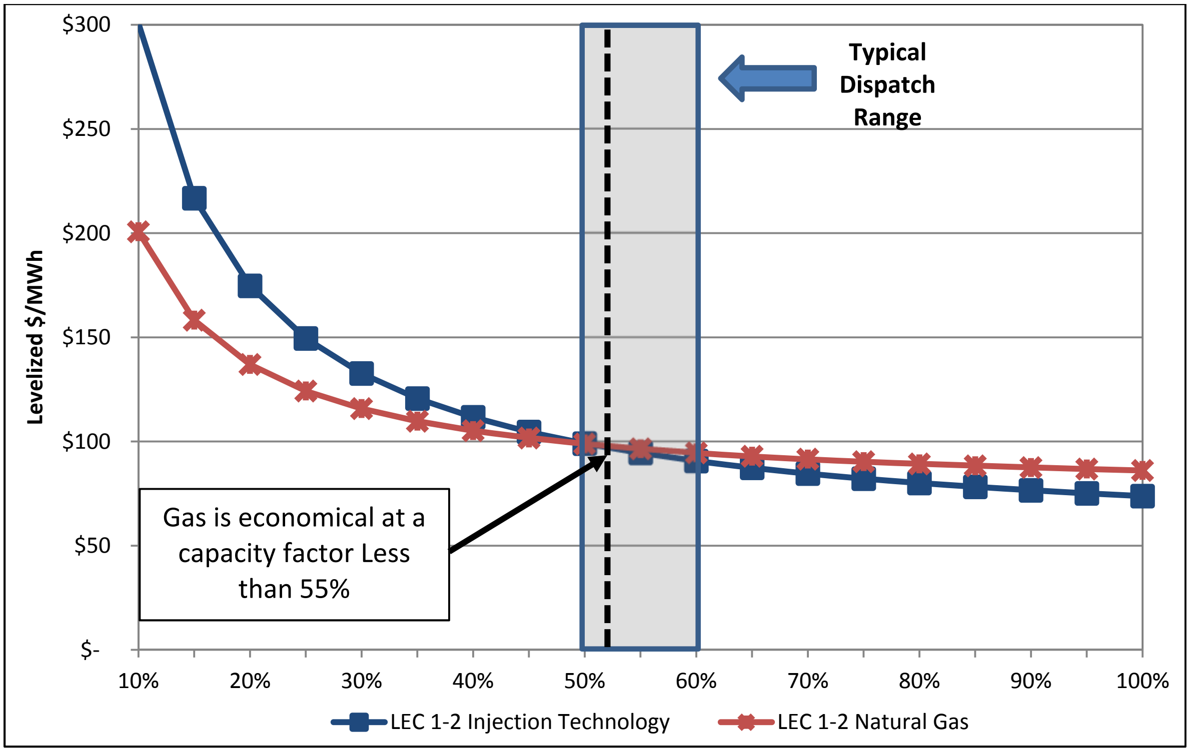


Figure 14--LEC Levelized Product Cost at Varying Capacity Factors ($-2016)

Figure 14 should be considered in context. It is a limited comparison of the two options and does not consider the remaining power supply resources. To clarify the MATS compliance options available, the natural gas refuel and injection technology alternatives were evaluated and compared through a full production cost analysis in the Strategist software. LEC as a natural gas facility is identified to be the lowest cost option under 1) Minnesota Power's base assumptions (as defined in Appendix H) and 2) a greenhouse carbon regulation penalty scenario where additional costs are placed on existing generating sources that emit CO_2 starting in 2017 of $21.50 per ton. In both outlooks refueling LEC to natural gas as an environmental compliance option has cost benefits of between $50 million and $90 million for customers when compared to installing injection technology. In the natural gas refuel option and with very minimal capital additions, Minnesota Power is able to optimize the natural gas operation of LEC with the regional market, bringing the lowest cost power supply option that ultimately brings savings to customers as illustrated in Table 3.

Table 3--LEC Power Supply Cost Comparison for MATS Solution

Strategist Power Supply Cost 2013-2034 NPV ($ Millions)	LEC Coal-Fired	LEC Natural Gas Refuel	Customer Impact (Gas Refuel – Coal-Fired)
Base Assumptions	$8,160	$8,110	($50)
With CO_2 Regulation Penalty ($21.50/Ton in 2017)	$9,763	$9,677	($86)

A natural gas refuel for LEC would bring many changes for its operations. There would be coal-fired generating equipment and systems that would require additional action, including the existing coal ash ponds and associated equipment. The cost for these transitions was factored into the refuel analysis.

To further determine if LEC should be shut down or continue operation after the MATS Rule deadline, the lowest cost environmental compliance option from Step 1 above (the natural gas refuel) was compared with an alternative to shut down the facility (Step 2). A generating unit closure analysis is complex and must take into account many pieces including the remaining plant asset balance at the time of the closure, costs related to decommissioning the facility, the impacts on the transmission system and socioeconomic impact on local communities. Remaining plant asset balance and decommissioning requirements were included in the shutdown alternative and assumptions for a ten-year recovery of these costs were assumed.[39] Through the shutdown alternative comparison, Minnesota Power conducted a local transmission evaluation to determine the impacts of having LEC removed from the power system and found that no reliability concerns would be created under current customer load outlooks (see Appendix F).[40]

While not included as a direct cost to the LEC shutdown alternative, Minnesota Power evaluated the socioeconomic impact on the local communities in conformance with state resource planning statutes. A partnership with the University of Minnesota

[39] The retirement mechanism for the remaining plant balance and decommissioning costs is based on the same methodology utilized in Minnesota Power's baseload diversification study and is included in Appendix H.
[40] Minnesota Power did not request MISO to conduct a region reliability study for LEC as its evaluation identified that moving forward with a natural gas refuel for the unit was the best outcome for customers and it would not be closing this unit. It is expected that LEC would not have significant impact on the regional reliability of the bulk transmission system due to its geographic location on the transmission system in northern Minnesota.

Duluth was established to leverage their expertise in evaluating the socioeconomic impact of a facility closure (see Appendix K). Their findings emphasized that Minnesota Power's generating facilities provide significant benefit to the communities and surrounding region through tax payments, employment and vendor utilization. If Minnesota Power were to close the LEC facility, the loss of 41 jobs and the associated support roles throughout the region would create a 2 percent increase in unemployment almost immediately for the area. Home prices could be expected to decline 5 percent as migration from the area increased as families leave to find new employment. An average of $10 million would be lost in revenue each year for the area economy after the closure. As demonstrated during the baseload diversification study process and associated stakeholder outreach, Minnesota Power has been a trusted community partner for decades and continues to consider these impacts of its electric service in a thoughtful way.

In Step 2 of the evaluation, a shutdown of LEC as a natural gas-fired facility was considered through the Strategist Proview software. The evaluation identified that LEC, as a natural gas resource, would continue to be a viable power supply resource for customers after the MATS compliance date with and without a carbon regulation penalty (see Appendix I). LEC operating as a natural gas unit provides a least-cost power supply alternative that significantly reduces emissions from a coal-fired operation.

Minnesota Power's short-term action plan includes converting LEC to natural gas in 2015. This will create Minnesota Power's first natural gas generating unit and aligns with the transformation and reshaping strategy that Minnesota Power is implementing to preserve reliability, protect affordability and reduce emissions for its customers.

Taconite Harbor Energy Center

THEC has been evaluated over the past year to determine the specific environmental compliance options that are available to allow the facility to meet the MATS Rule. The commission requested as part of the outcome of the baseload diversification study further evaluation of THEC, specifically Unit 3 and that Minnesota Power include in its 2013 IRP:

> *"A proposal to address the viability of Laskin Energy Center, Units 1 and 2, and Taconite Harbor Energy Center, Unit 3."*

This section will describe the continuation of Minnesota Power's development of environmental compliance alternatives and viability for THEC3 and support the decision in its short-term action plan that continuing the operation of THEC1&2, while ceasing coal-fired operation at Unit 3 in 2015, is in the best interest of customers.

THEC is located near Schroeder, Minnesota, on the North Shore of Lake Superior, and has a generation capability of 225 MW. The generators all operate at high capacity factors on an annual basis of 60 to 75 percent, providing baseload energy for Minnesota Power's customers. The three 75 MW units were purchased from bankrupt LTV Steel Mining Co. in 2001. Significant investment was made as the units were restarted in 2002. THEC employs 45 full-time Minnesota Power employees. The three generating units are housed in a single building with shared electrical and heating infrastructure and a single control room for unit operations. The facility does not have direct access to natural gas as a fuel source, no pipeline is present and the closest access is 30 miles to the south in Silver Bay, Minnesota. The facility is located at an active shipping port on Lake Superior and receives coal shipments via boat for its operations.

The THEC units received significant investment in the period 2006 to 2008 as part of Minnesota Power's AREA Plan. THEC1&2 were fitted with Mobotec multi-emission control technology designed to deliver a 62 percent reduction in NO_x emissions, a 65 percent reduction in SO_2 emissions and up to a 90 percent reduction in mercury emissions. Conversion of the hot-side electrostatic precipitator ("ESP") to a cold-side ESP for improved particulate removal also took place in this time period. The final mercury removal system is being installed on these two units. THEC1&2 are well positioned to meet the requirements of the MATS Rule in 2015. Sorbents will be utilized with the existing Mobotec injection system to reduce mercury and other air emissions below required thresholds.

The additions of sorbents to THEC1&2 will have positive environmental benefits; however, they will add costs to the unit operations. These operational costs add on average $3.20/MWh to the current THEC operating costs. Mercury emissions will be reduced to MATS requirement levels by adding activated carbon sorbents into the boilers. The combined sorbents being added to remove mercury will also have a positive impact on SO_2 removal and Minnesota Power should see an additional 30 percent reduction in these emissions.

The additional costs for the sorbents were evaluated through a full production cost analysis in the Strategist software and compared to existing operations. As Table 4 below identifies, a 0.3 percent increase (or approximately $20 million) in overall power supply system costs was estimated for the study period when the sorbents were added to THEC1&2 under scenarios with and without a carbon regulation penalty. The previous AREA investment creates a viable mechanism to meet the MATS Rule requirements without additional capital investment. As demonstrated below, these additional operating costs for THEC1&2 do not impact the viability of the generating resources.

Table 4--Change in Power Supply Cost with THEC1&2 MATS Solution

Strategist Power Supply Cost 2013-2034 NPV ($ Millions)	THEC1&2 Base Case	THEC1&2 Additional Sorbents	Customer Impact (Sorbents – Base)
Base Assumptions	$8,147	$8,172	$25
With CO_2 Regulation Penalty ($21.50/Ton in 2017)	$9,750	$9,773	$23

THEC3 does not currently have the necessary emission controls in place to meet the upcoming MATS requirements. THEC3 is fitted with a hot-side ESP for particulate control and also utilizes low sulfur, low mercury coal. THEC3 is categorized as a Regional Haze unit for Minnesota and, until the MATS Rule was finalized, was on track to add injection technology controls similar to those installed on THEC1&2 to meet the NO_x and SO_2 requirements in 2017. The MATS Rule now requires THEC3 to meet additional air emission requirements in 2015. A multi-pollutant environmental retrofit alternative to meet both Regional Haze and MATS requirements was developed for THEC3; however, refuel is not viable at this time as natural gas is not in close proximity to the site.[41]

The multi-pollutant retrofit alternative developed for THEC3 includes a scrubbing technology, similar to the proposed BEC4 Project, able to handle a multi-pollutant reduction for both MATS and Regional Haze regulations. This project alternative consists of installing a Hitachi Power Systems America Enhanced All-Dry scrubber and Pulse Jet Fabric Filter for treating THEC3 flue gas for control of SO_2 and PM, respectively. Additionally, a powdered activated carbon injection would be employed for control of mercury emissions. To address NO_x emissions an additional project to install low NO_x burner and over fired air technology was also included. Estimated capital cost for this alternative is $60 million with increased variable costs of approximately $2.50 per MWh. Emission reduction would be approximately 90 percent for SO_2 and mercury and 60 percent for PM after the installation is complete.

The multi-pollutant environmental retrofit alternative was evaluated and compared to existing operations through a full production cost analysis in the Strategist software. Table 5 below identifies a 0.7 percent increase in overall power supply system costs (or approximately $60 million) is estimated for the study period when the retrofit is added to THEC3 under scenarios with and without a carbon regulation penalty. The power supply impacts of the THEC3 retrofit alternative are twice the impact of

[41] Biomass as a fuel source can be considered in the future, however at this time is not an economical option due to fuel handling and boiler modifications that would be required.

THEC1&2, indicating that THEC3 requires significant investment for ongoing operations.

Table 5--Change in Power Supply Cost with THEC3 MATS Solution

Strategist Power Supply Cost 2013-2034 NPV ($ Millions)	THEC3 Base Case	THEC3 Multi-pollutant Retrofit	Customer Impact (Retrofit – Base Case)
Base Assumptions	$8,147	$8,209	$63
With CO_2 Regulation Penalty ($21.50/Ton in 2017)	$9,750	$9,811	$62

To determine if THEC3 remains a viable option for customer power supply or if a shutdown is needed due to the MATS Rule deadline, the environmental compliance alternative above was compared with an alternative to shut down the unit. A generating unit closure analysis is complex and includes many considerations including the remaining plant asset balance at the time of the closure, costs related to decommissioning the facility, and the impacts on the transmission system and socioeconomic impact on local communities. In this case, if one unit at a facility is shut down there are increased costs for the remaining two units, as not all facility-wide operating cost reductions can be taken as with a full facility shutdown. Staff is still required to conduct the remaining operations. THEC has been operating very efficiently with only 45 staff, so reductions would be minimal and the remaining operating costs would be spread over a smaller power production from just THEC1&2. Minnesota Power increased the costs associated with THEC1&2 in the THEC3 shutdown alternative to accurately reflect this dynamic. An increase in costs for a generating facility leads to a question of whether the viability of the remaining generating units are in jeopardy; therefore, Minnesota Power continued to evaluate THEC1&2 as it conducted its shutdown evaluation in its 2013 Plan.

Through the shutdown alternative comparison, Minnesota Power conducted a local transmission evaluation to determine the impacts of having THEC3 removed from the power system, and found that no reliability concerns would be created under current customer load outlooks (see Appendix F). However, when the entire THEC facility is removed (all three units) there are transmission reliability concerns, for which upgrades are required to ensure the electric service to Minnesota Power customers can be maintained.[42] Remaining plant asset balance and decommissioning requirements were

[42] Minnesota Power is not recommending the closure of the entire THEC facility; therefore, did not include additional transmission costs into the shutdown alternatives identified in the transmission evaluation.

included in the shutdown evaluation and assumptions for a ten-year recovery of these costs were included.[43]

While not included as a direct cost to the THEC shutdown alternative, Minnesota Power evaluated the socioeconomic impact on the local communities in conformance with the Commission's resource planning rules. A partnership with the University of Minnesota Duluth was established to leverage their expertise in evaluating the socioeconomic impact of a facility closure (see Appendix K). Their findings emphasized that Minnesota Power's generating facilities provide significant benefit to the communities and surrounding region through tax payments, employment and vendor utilization. If Minnesota Power were to close the THEC facility, the loss of 45 jobs and the associated support roles throughout the region would create a 2 percent increase in unemployment almost immediately for the area. Home prices could be expected to decline 6 percent as migration from the area increased as families leave to find new employment. Overall, the loss of revenue and wages would contribute to $14 million in loss each year for the area after the closure. As demonstrated during the baseload diversification study process and associated stakeholder outreach, Minnesota Power has been a trusted community partner for more than a decade and continues to consider these impacts of its electric service in a thoughtful way.

To ensure a robust analysis of the shutdown alternatives for this facility, the option to retire THEC3 and/or THEC1&2 was included in a system wide optimization evaluation in the Strategist Proview software. The shutdown alternative was considered with the rest of the power supply system and new resource alternatives. The evaluation identified that all three units should continue as coal-fired generation after the MATS compliance date and that shutdown was not an economic option for customers under Minnesota Power's base assumptions. However, when a carbon regulation penalty was applied to the evaluation, the scenario identified that THEC3 should be shutdown in 2015 before the MATS compliance date and prior to the need to invest in the retrofit alternative.

The carbon regulation penalty scenario further indicated that THEC1&2 should be considered for shutdown once a carbon regulation penalty is active, as the additional cost from the carbon penalty ($21.50/ton) under current industry outlooks makes these generating resources less economical for customers. Currently, there are no greenhouse gas regulation penalty provisions in place or pending. As Appendix E describes, there are other policy mechanisms that are helping to drive down carbon production and a penalty provision may not occur. At the same time, significant uncertainty remains on the outcome of greenhouse gas regulation. Minnesota Power is committed to continuing to reduce its carbon intensity and reduce emissions in-line with state goals.

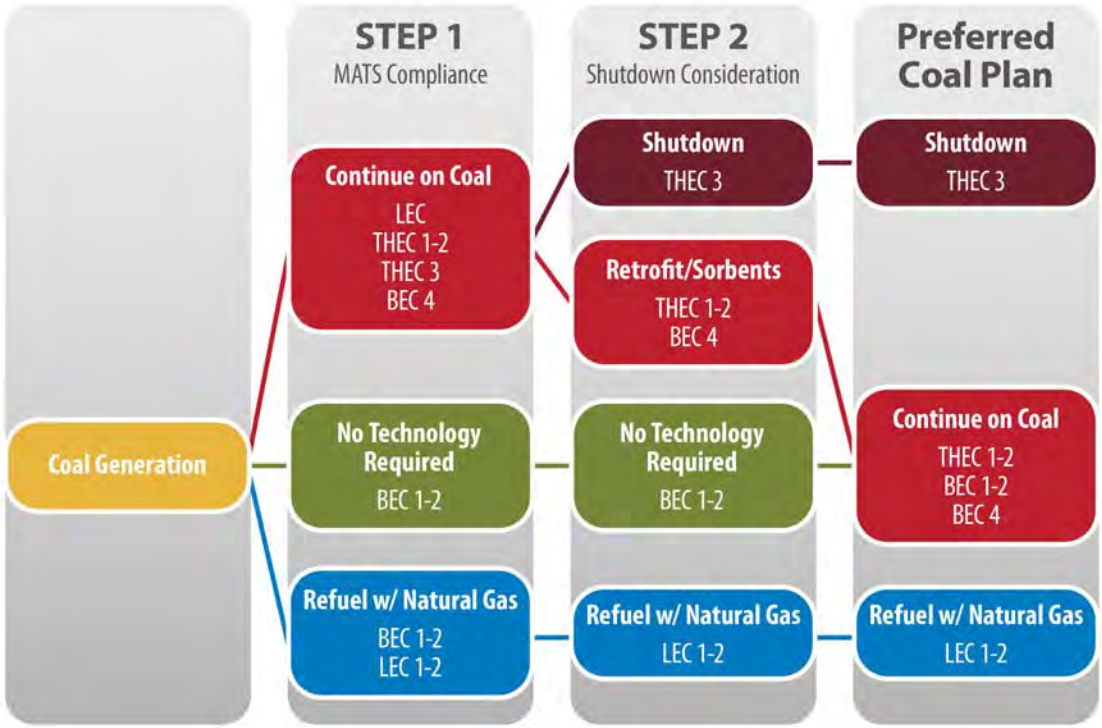
[43] The retirement mechanism for the remaining plant balance and decommissioning costs is based on the same methodology utilized in Minnesota Power's baseload diversification study and is included in Appendix H.

For its short-term action plan, Minnesota Power has identified that the investment in retrofit technology for THEC3 (approximately $60 million) would not be in the best interest of its customers. To protect affordability for customers in the near term and reduce emissions further in the region, Minnesota Power will proactively cease coal operation for the THEC3 75 MW generating resource by April 2015. This action will occur prior to the MATS compliance deadline and will avoid the $60 million cost in retrofit technology and associated annual O&M. The THEC3 equipment will physically remain in place at the THEC facility as it is tightly integrated into the current operations. Future utilization of the asset and its components can be considered in future planning and optimization of the THEC facility (see Appendix L). Minnesota Power will begin the MISO Attachment Y notification process in 2013 to confirm no additional regional transmission considerations will be needed before 2015. The THEC3 shutdown will reduce overall emissions, and specifically carbon emissions, by approximately 500,000 tons per year starting in 2015. Replacement for the capacity and energy that will be lost in 2015 is considered in Minnesota Power's expansion planning in Step 3 of this evaluation.

Minnesota Power recognizes that carbon policy is a key driver for the cost effectiveness of its thermal generating facilities and will continue to monitor through the resource planning process the evolving industry outlooks and key changes in environmental regulations. The shutdown evaluation for THEC1&2 identified that customer costs would be impacted by a large carbon penalty. Minnesota Power will include in its long-term action plan that it will continue operation of these two facilities and monitor THEC1&2 economics during the 2018-2027 time period to determine these units' competitive position. Taking action now to shut down these environmentally well controlled units that also have a minimal impact compliance plan for the MATS Rule would be a premature and reactive action to a speculative carbon regulation signal that is not yet in place or may not develop. By increasing customer costs unnecessarily without a carbon regulation, customers would lose the benefit of the recent investment in significant emission controls put into place at the facility as part of the AREA Plan and cause unnecessary negative socioeconomic impact to the host communities.

Conclusions for Small Coal

Minnesota Power has taken the necessary time since its baseload diversification study and the finalization of the MATS Rule to evaluate specific environmental compliance strategies for its coal-fired fleet. Under its most up-to-date outlooks and with engineering estimates taken into consideration, Minnesota Power is confident that its small coal strategy and action steps included in its Preferred Plan are the best path forward for customers. Utilizing least cost alternatives and protecting affordability, Minnesota Power will refuel LEC to natural gas, cease operations at THEC3 to proactively reduce emissions, and continue operation of its remaining coal-fired fleet (see Figure 15). This includes adding a key environmental retrofit to its largest resource, BEC4, and operating its coal-fired fleet as baseload resources for its customer power supply requirements as well as continuing to closely monitor resource viability of THEC1&2 in its long-term action plan.



Note: BEC3 has already been retrofitted with a multi-pollutant technology and does not require additional investment. Minnesota Power will continue to operate this unit as a coal-fired facility (see Appendix C).

Figure 15--Minnesota Power Preferred Plan for Coal-Fired Fleet

Recognizing that a wide range of plausible futures should be considered, Minnesota Power incorporated into its evaluation a comparison of the other key options available for compliance with the MATS Rule. The comparison will allow stakeholders to consider the impact of not only Minnesota Power's Preferred Coal Plan, but also three alternative paths for Minnesota Powers coal-fired facilities that include:

1. Retrofit all Minnesota Power's coal-fired facilities with needed emission reducing technology to meet the MATS Rule
2. Close Minnesota Power's LEC and THEC entirely
3. Implement Minnesota Power's Preferred Coal Plan and close THEC1&2

These alternative paths are illustrated in Figure 16.

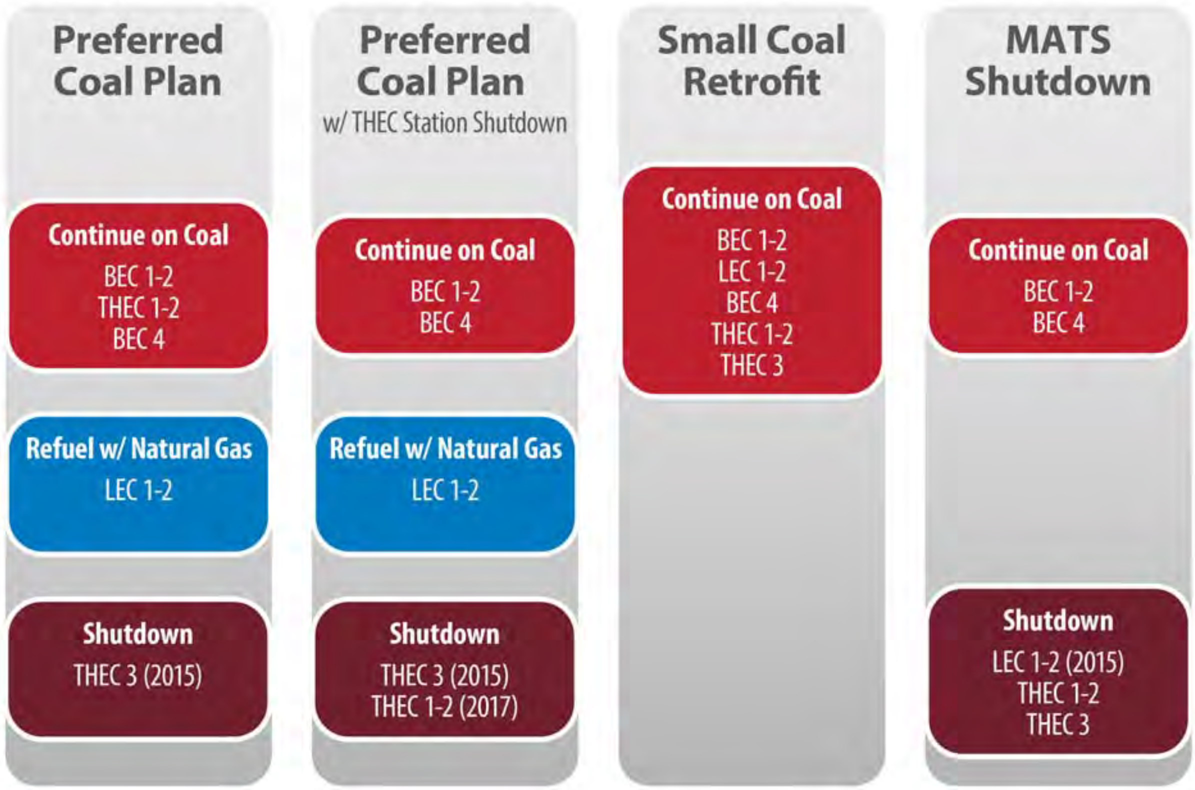


Figure 16--Coal Strategy for Preferred Plan and Three Alternative Swim Lanes

The Analysis and Insight section (see page 63) will compare and contrast these alternative outcomes for Minnesota Power's coal-fired fleet. First, expansion plans for additional resources that will augment the small coal plan must be considered in order to create Minnesota Power's complete Preferred Plan. These new resources are discussed in the next two sections.

Expansion Planning for New Generation Resources

Minnesota Power is considering many technologies to help serve its growing customer power requirements. Solar, wind, storage, biomass, traditional natural gas, and clean coal thermal generation are the major categories Minnesota Power is monitoring that are emerging and improving. Appendix I identifies how Minnesota Power screens available alternatives for its resource planning evaluation. For its 2013 Plan, Minnesota Power identified primarily wind and natural gas technologies (both small and large options) along with expanded DSM to best position the Company to meet its growing power supply needs.

This resource selection does not indicate that Minnesota Power has a position on any particular emerging technology. In many cases, the Company supports further advancement of developing technologies through regional studies and academic research as described in Appendix D, or through partnership on distributed generation projects as described in Appendix C. Resource options continually evolve, and for its 2013 Plan Minnesota Power utilized the lowest cost resources from each of the baseload, intermediate and peaking resource categories to help determine the best fit for its power supply needs. Further, the Commission requested as part of the outcome of the baseload diversification study specific consideration of wind and natural gas technologies and that Minnesota Power include in its 2013 IRP:

> *Scenarios that add 100 to 200 MW of wind capacity in the 2014-2016 time frame.*
>
> *Scenarios that add 400 to 600 MW of natural gas capacity in the 2014-2016 time frame.*

Minnesota Power utilized the Strategist Proview software for expansion planning. The software allows a utility to offer many resources into an evaluation and optimizes which technologies best fit to meet projected customer needs over a defined study period. Through its resource screening and the requested scenarios from the Department, Minnesota Power allowed the Strategist Proview software to select from the following resource options:[44]

i. 200 MW share of a natural gas fired 1x1 combined cycle
ii. 198 MW natural gas fired combustion turbine
iii. 55 MW natural gas fired reciprocating internal combustion engine
iv. 105 MW wind farm located in North Dakota.
v. 50 MW bilateral bridge transaction

Using this approach and the selected resource options ensured that Minnesota Power would meet the request of the Department and allow the optimization process to choose from the lowest cost resources. A DSM peak shaving program was also considered as a supply side resource (see Appendix B) and as a specific sensitivity evaluation which will be discussed later in the section.

Minnesota Power's Preferred Plan for its coal-fired generation results in approximately 70 MW less capacity resource available due to the closure of THEC3.[45] Minnesota Power's updated capacity resource position from Section III is included below and was the starting point for the expansion planning (Step 3) of the evaluation. Minnesota Power has less than 200 MW of capacity need for the majority of the 15-year planning period, most of which is required after 2020 as shown in Figure 17.

[44] Note that more than one of each resource option can be chosen during the optimization process.
[45] The full nameplate capability of THEC3 is 75 MW, however, due to transmission system constraints only 66 MW of capacity is possible from the unit.

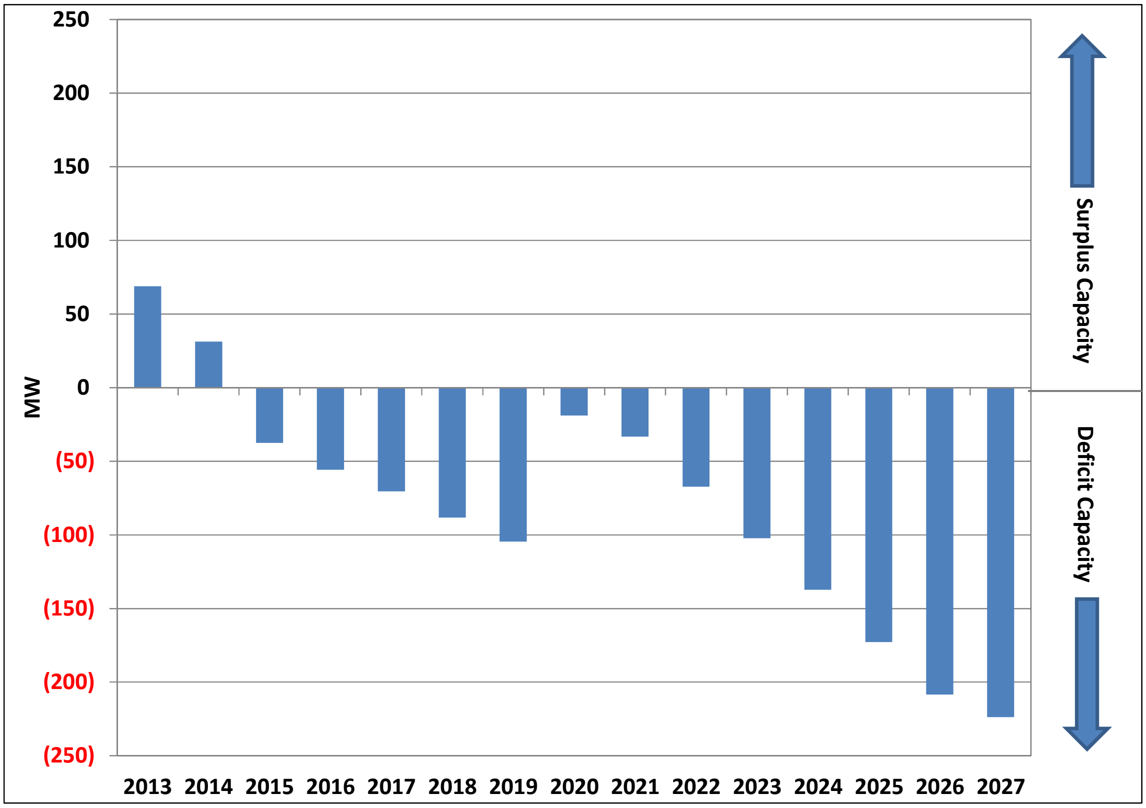


Figure 17--Updated Summer Season Capacity Position with preferred Coal Plan

The expansion plan optimization was conducted for two scenarios: 1) Minnesota Power's base assumptions (as defined in Appendix H) and 2) a carbon regulation penalty scenario where additional costs are placed on existing generating sources that emit CO_2 starting in 2017 of $21.50 per ton. The lowest cost power supply expansion plans are shown in Table 6 below.

Both expansion plans are very similar, identifying that in the short term wind and bilateral transactions are the most economic resource additions due to regional power market surpluses and the extension of the PTC for wind generation. The long-term expansion plan identifies that natural gas and additional wind would be beneficial if a carbon regulation penalty is enacted. The fact that these two expansion plans are similar, especially in the short term, provides confidence that these actions will be prudent in both a future with and without a carbon penalty regulation.

Table 6--Minnesota Power's Preferred Plan Resource Actions

	Preferred Plan	Preferred Plan *if CO_2 regulation implemented*
Short-Term (2013-2017) Actions		
Small Coal Shutdown/Refuel:		
Taconite Harbor 1-2		
Taconite Harbor 3	X	X
Laskin (Refuel to Gas)	X	X
Boswell 1-2		
Resource Additions:		
Combustion Turbine		
Combine Cycle (partial share)		
Reciprocating Engine		
Wind	X	X
Bilateral Bridge Transaction	X	X
Long-Term (2018-2027) Actions		
Small Coal Shutdowns:		
Taconite Harbor 1-2		
Taconite Harbor 3		
Laskin		
Boswell 1-2		
Resource Additions:		
Combustion Turbine		
Combine Cycle (partial share – 200 MW)	X	X
Reciprocating Engine		
Wind		X (2)
Strategist Power Supply Cost 2013-2034 NPV:	**$8.29 B**	**$9.73 B**

The expansion plan for the Preferred Plan also highlights the extreme difference in power supply costs that a carbon regulation penalty future could bring to customers. Over $1 billion dollars in cost is added to customers' power supply costs with essentially the same recommended power supply generation additions. As further described in Appendix E, the addition of a carbon regulation penalty does not always drive significantly different power supply outcomes and in many cases, unnecessarily increases costs of electric supply for customers.

Natural Gas

Minnesota Power has identified through both its baseload diversification study and now its 2013 Plan evaluation that natural gas technology is showing benefits for its long-term power supply diversification. The LEC refuel will provide Minnesota Power its first fully natural gas-fired unit in 2015 (110 MW) and provide valuable peaking generation and a MATS compliance solution for the facility. The 2020 and beyond time period in both expansion plans noted in Table 6, identified 200 MW natural gas additions to augment a growing customer base and renewable power supply. Natural gas fits well with intermittent generation like wind, as the technology is typically a flexible, fast acting resource that can be present to deliver energy when wind is not available. The expansion planning identified that an efficient and low cost natural gas product, such as a portion of a combined cycle ("CC") generating unit, should be considered over a combustion turbine ("CT"). Minnesota Power's high load factor and energy intensive customers gain value from generating resources that can produce efficient, low cost energy. It is important to note in this finding that a full sized 1x1 CC resource was not identified. This resource would have added over 400 MW of additional generation, much more than Minnesota Power's identified need in its base case outlook. The expansion plan demonstrates that a partial ownership share in a larger facility could provide benefit to customers over the smaller natural gas technologies; however, this will have to be carefully considered in the final stages of planning, as the CT technology is very close in size (200 MW) and could also be added to help meet Minnesota Power's long-term requirements.

Minnesota Power will conduct additional evaluation and planning for the specific size, type, location and timing of a new natural gas resource. As Minnesota Power's load growth materializes later this decade and as additional environmental regulations gain more certainty, Minnesota Power will be able to address the specifics of its next phase of natural gas strategy. Considerations will include procurement versus build options, transmission requirements, regional integration, and fuel procurement. The Company's long-term action plan identifies that Minnesota Power will advance its planning for a natural gas resource for the 2020 time period.

Wind Generation

Both expansion plans, with and without a carbon regulation penalty, identified the addition of wind generation in the pre-2020 timeframe. The extension of the PTC for wind in late 2012 was a late breaking development for consideration in Minnesota Power's 2013 Plan evaluation. With several unknowns of this PTC extension including the application and limitations, Minnesota Power, along with the rest of the industry, is still evaluating the full impact this will have on near term resource plans.

Minnesota Power's expansion plan under its base assumptions identified that 100 MW of additional wind could provide significant value for customers if the cost of the wind was below $50 per MWh with the PTC. This is a preliminary threshold and indicator utilized from the baseload diversification study.[46] Minnesota Power is already ahead of its implementation plan for meeting its renewable energy requirements for the state RES (see Appendix G) and it has done so economically to the benefit of its customers. However, the Company has identified that based on its projection for current load growth, additional renewable resources will be needed to meet the longer-term 2025 requirement of 25 percent. Consequently, Minnesota Power has identified a renewable strategy that includes the addition of 200 MW of high capacity factor wind energy similar to Minnesota Power's current Bison projects near Center, North Dakota to meet this requirement.

The expansion planning process identified that pursuing a minimum of 100 MW and up to 200 MW of low cost wind energy could have multiple benefits for Minnesota Power's customers. It could provide a least cost plan for meeting the 2025 RES requirement if it is possible to take advantage of the recent PTC extension.

A competitive request for proposal process will be initiated for up to 200 MW of wind as part of Minnesota Power's short-term action plan to determine what cost range is available for implementing additional wind on its system. If cost-effective and in the customers' interests, the Company will pursue Commission approval in the 2013-2014 timeframe to expand its supply portfolio with additional wind energy.

Bilateral Bridge Transactions

Another important component of a utility's power supply are contracted purchases and sales conducted within the industry to optimize the power surpluses and deficits that occur due to industry load and supply changes. These agreements are called bilateral transactions and they allow Minnesota Power to work with other entities to procure energy and capacity from existing resources (see Appendix C for a list of Minnesota Power's current bilateral transactions included in the Base Case).

A bilateral transaction is functionally different than the day-ahead regional energy and capacity markets represented by the MISO tariff construct. Bilateral transactions are typically forward, medium to longer-term contracts with defined pricing terms, while day-ahead markets operate in the 24-hour to 48-hour time frame with spot market prices (see Appendix H). Minnesota Power monitors the bilateral power markets to identify opportunities to contract with other entities when it is in the best interest of its customers. In the Preferred Plan, a short-term bilateral bridge purchase allows Minnesota Power to delay further investment in new generation resources until 2023. Around 2023, a 200 MW share of a CC resource is added in the Plan, providing significant savings to customers when compared to a wholly-owned resource while bilateral bridging agreements provide near term stability in power supply costs.

[46] Minnesota Power is still evaluating the full impact of the PTC extension and will engage in a request for proposal process to determine the wind costs for customers as part of its short-term action plan.

These bilateral purchases have a distinct role in meeting customers' energy needs and are not a standing approach to supplying customers in the long term. Rather, they are a distinct opportunity for very economical shorter-term (several year) energy supply given the current low demand for power in the wholesale energy market. This approach of using stably priced, bilateral purchases with strong counterparties for shorter-term power supply helps mitigate electricity requirements. It also allows for flexibility as large new customer loads materialize on Minnesota Power's system, given the wide range of load growth projections illustrated in the AFR2012.[47]

Demand Side Management

Minnesota Power currently has in place a significant amount of DSM capability (over 100 MW) on its system. Through its partnership with its Large Industrial Customers and its Dual Fuel Rate programs with its Residential and Commercial customers, these existing programs provide a valuable component of Minnesota Power's least cost supply strategy and help to ensure the reliability of the regional power system.

Minnesota Power is investigating additional demand response opportunities through the evaluation of a peak shaving program for air conditioning ("AC") customers. Minnesota Power's load forecast process (see Appendix A) identified an increasing trend in air conditioning saturation for its customers. Typically a winter peaking utility, Minnesota Power previously focused its residential and commercial demand response programs on electric heating characteristics of its load. However, with the emerging air conditioning use trend, an AC interruption program might benefit the power supply. Through a preliminary design process identified in Appendix B, Minnesota Power created an AC cycling program for consideration in its expansion planning.

Based on the AC peak shaving program design and the current projection of AC saturation on Minnesota Power's system, there is an estimated 7 MW available for this type of program by 2017. The net present value of the sample AC cycling program's costs is estimated to be $1,550/kW, as described in Appendix B. This is a higher cost resource option compared to other supply side alternatives Minnesota Power is utilizing in its expansion planning. Therefore, this demand side resource option was analyzed as a sensitivity and added to the Preferred Plan in the Strategist software in order to evaluate the cost and benefits of the AC cycling program.[48] Table 7 identifies the power supply costs with and without the AC cycling program and indicates that implementing this type of program under current outlooks would increase the cost to customers, rather

[47] As Minnesota Power has experienced in its past, surplus generating assets due to large industry cyclicality has wide-sweeping implications as was seen with the BEC4 commissioning (Docket No. E002, 015/PA-86-722). Minnesota Power believes a more paced resource addition strategy best serves its customers.
[48] If the demand side resource was added to the expansion planning optimization with other lower cost alternatives, it would be less likely for the option to be selected. Minnesota Power wanted to understand how a DSM peak shaving program would impact its power supply; therefore, it was analyzed as a sensitivity.

than reduce it. Due to the expected availability of lower cost capacity resources, the AC cycling program is not showing economic benefits at this time.

Table 7--AC cycling Program Sensitivity on Preferred Plan

	A Preferred Plan	B Preferred Plan w/ AC DSM Program	Customer Impact (B-A)
Strategist Power Supply Cost 2013-2034 NPV ($ Millions)	$8,288	$8,302	$13

The initial design and investigation of an AC cycling program is a good starting point for identifying beneficial DSM options for Minnesota Power's system. Along with a strong dedication to conservation, as demonstrated by its exceptional CIP performance, Minnesota Power has a significant amount of DSM capabilities developed through the longstanding commitment and relationships with its customers. Minnesota Power will continue to work to identify reasonable additions to its DSM programs that will most benefit customers.

Analysis and Insights - Comparison of Preferred Plan to Alternatives and Sensitivity Analysis

Minnesota Power considered its Preferred Plan plus three primary alternative paths for its coal-fired generation fleet to meet compliance with the MATS Rule as shown in Figure 16 on page 56. These paths also reflect the main alternatives expressed by external stakeholders:

1. Retrofit all Minnesota Power's coal-fired facilities with needed emission reducing technology to meet the MATS Rule
2. Close Minnesota Power's LEC and THEC entirely
3. Implement Minnesota Power's Preferred Coal Plan and close THEC1&2

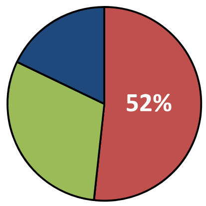
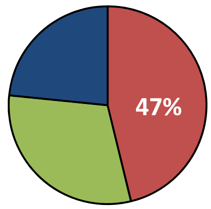
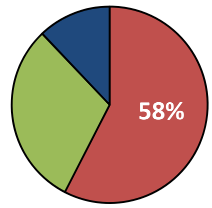
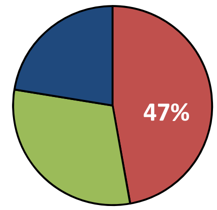
Minnesota Power wanted to verify whether or not these alternative paths, or swim lanes, were in the best interests of customers compared to the Preferred Plan and to further assess the benefits of its Preferred Plan for stakeholders. The three swim lane alternatives were first put through Minnesota Power's expansion planning process for direct comparison to the Preferred Plan. In this process, the least cost power supply additions were identified for each option (see Appendix I). The expansion plan for each alternative contains similar resource additions to Minnesota Power's Preferred Plan, demonstrating the resilient nature of Minnesota Power's short and long term action plans. These additions include:

- A 100 MW wind addition is made across all swim lanes, reflecting the benefit of the potential for reduced wind costs due to the PTC extension.

- With the exception of the Retrofit Small Coal Plan, all swim lanes utilize some amount of short-term bilateral bridge purchase, reflecting the benefit that economical short-term purchases provide to improving the timing of new generation additions.
- With the exception of the Retrofit Small Coal Plan, the next thermal generation resource alternative added is a 200 MW share of a CC facility, reflecting the benefit of additional efficient natural gas generation.

Table 8 provides an overview of each of the alternatives and gives the highlights of the initial Strategist evaluation for the options. The plans vary slightly in terms of generation mix and estimated emission reductions; however, the Preferred Plan is the lowest cost under the base assumptions utilized.

Table 8--Overview of Preferred Plan and Swim Lane Alternatives

Portfolio Name	Preferred Plan	Preferred Plan w/ THEC Station Shutdown	Small Coal Retrofit	MATS Shutdown
Energy Portfolio by 2027				
	Coal	Renewables	Natural Gas + Purchases	
2013 NPV of Plan Costs	**$8.29 B**	**$8.35 B**	**$8.32 B**	**$8.41 B**
Renewable: Installed Capacity & Contracts 2027 (MW)	**989**	**989**	**989**	**989**
Coal: Installed Capacity 2027 (MW)	**1,095**	**962**	**1,262**	**962**
Natural Gas: Installed Capacity 2027 (MW)	**296**	**494**	**198**	**453**
CO_2: Cumulative Reduction from 2013–2027 (Tons)	**15.8 M**	**21.3 M**	**4.9 M**	**24.4 M**
Mercury: Cumulative Reduction from 2013–2027 (lbs.)	**4,259**	**4,356**	**4,093**	**4,396**
Other Emissions: Cumulative Reduction from 2013–2027 (Tons)	**107,400**	**128,100**	**88,400**	**134,400**

Each swim lane alternative and the Preferred Plan were then put through a series of 21sensitivities that stressed the main drivers for resource decisions including fuel, capital, additional EPA regulation and carbon sensitivities. The sensitivities help determine whether the Preferred Plan and its resource actions would be the best option for customers if these drivers were to vary from the current base case outlooks.

The Preferred Plan provided the low cost power supply in over 50 percent of the sensitivities considered. The Preferred Plan represents a diverse generation portfolio fuel mix that allows flexibility for Minnesota Power to take advantage of changing fuel cost and/or carbon regulation trends in the future. Only an extreme drop in natural gas prices from the expected forecast or a carbon regulation penalty would favor a THEC facility shutdown along with the Preferred Plan. Minnesota Power considers an extreme drop in natural gas that is sustained for the long term unlikely given the current outlooks. Minnesota Power identified that THEC1&2 have no additional environmental capital requirements to meet the MATS Rule. This will keep future closure costs lower and provide the Company more flexibility when determining options for this facility if new regulations arise.

ensitivity Analysis: 2013 NPV of Alternative Cost with Sensitivities ($millions)

ties	Preferred Plan	Preferred Plan w/ THEC Station Shutdown	Retrofit Small Coal	MATS Shutdown
sumption	$8,288	$8,349	$8,318	$8,409
pital Cost (-30%)	$8,214	$8,213	$8,268	$8,242
pital Cost (+30%)	$8,455	$8,577	$8,460	$8,668
nalty $9/ton	$8,796	$8,835	$8,852	$8,890
nalty $21.50/ton	$9,733	$9,715	$9,861	$9,764
nalty $34/ton	$10,648	$10,574	$10,849	$10,620
l Forecast (-30%)	$7,650	$7,775	$7,596	$7,848
al Forecast (+30%)	$8,901	$8,910	$9,011	$8,959
mass (-10%)	$8,275	$8,336	$8,305	$8,396
mass (+10%)	$8,301	$8,361	$8,331	$8,422
atural Gas (-50%)	$8,032	$7,977	$8,187	$8,023
ural Gas (-25%)	$8,165	$8,184	$8,256	$8,234
tural Gas (+25%)	$8,396	$8,489	$8,388	$8,567
latural Gas (+50%)	$8,496	$8,601	$8,454	$8,701
ernality Values	$8,054	$8,124	$8,064	$8,190
ternality Values	$8,523	$8,574	$8,572	$8,629
olesale Market (-50%)	$7,868	$7,906	$7,951	$7,988
olesale Market (+50%)	$8,566	$8,629	$8,562	$8,680
lesale Market	$8,487	$8,456	$8,462	$8,536
lesale Mkt w/CO2 Penalty $21.50/ton	$9,962	$9,853	$10,059	$9,921
l Program	$8,302	$8,364	$8,333	$8,423
al Environmental Regulations	$8,456	$8,503	$8,509	$8,563
nt	**12 plans**	**6 plans**	**4 plans**	**Zero plans**

ding in Table 9 indicates the lowest cost alternative.

The MATS shutdown swim lane, which assumes a shutdown at both the LEC and THEC facilities, is not identified as the lowest cost option under any of the 21 sensitivities. In addition, the socioeconomic impacts that unit closures would have on communities is negative. According to initial evaluation, the two communities would see a total of approximately $28 million in loss of revenue and wages each year after shutdown, as well as a loss of up to 200 jobs. See Appendix K for additional details on the socioeconomic impact of unit closures Minnesota Power considered in this analysis.

The potential for additional EPA regulations was considered as a sensitivity to include costs for the coal ash residual and steam effluent guidelines currently being contemplated (see Appendix E). This sensitivity added costs to each generation facility under the current expectation for the rules. As Table 9 identifies, the Preferred Plan continues to be the lowest cost alternative for customers when compared to the other swim lane options.

Minnesota Power's customers would see unnecessarily increased costs if the Company were to take action in its Preferred Plan to protect against only a chance of extremely low natural gas prices or a mid to high carbon regulation penalty. Minnesota Power will have the flexibility through its ongoing resource planning process with the Commission and its stakeholders to consider alternate actions if these outcomes were to unfold in future resource plan cycles.

The sensitivities and consideration of the swim lane alternatives help solidify that the Preferred Plan will meet its goal to balance improving environmental performance, preserving reliability and protecting affordability for customers.

Characteristics of Minnesota Power's Preferred Plan

The Preferred Plan continues the transition of Minnesota Power's fleet to become more diverse, more flexible and less emitting. To accomplish this, the Company is taking major steps that address a changing energy business environment and responding to the Commission's Orders in the 2010 Plan Docket. The Preferred Plan implements both capacity and energy resource changes that will provide a more balanced supply portfolio with the least cost for customers reaching 50 percent coal-fired generation by 2027. The 2013 Plan will move Minnesota Power toward its *Energy**Forward*** resource strategy and a supply that is made up of a third renewable, a third coal-fired, and a third natural gas and purchases over the long term. It protects affordability, preserves reliability and sustains environmental stewardship.

Figures 18 and 19 demonstrate the resulting capacity and energy position of the Preferred Plan. The 2013 Plan reduces coal-fired generation by 20 percent and doubles renewables and introduces natural gas to meet the projected load growth in the planning period.

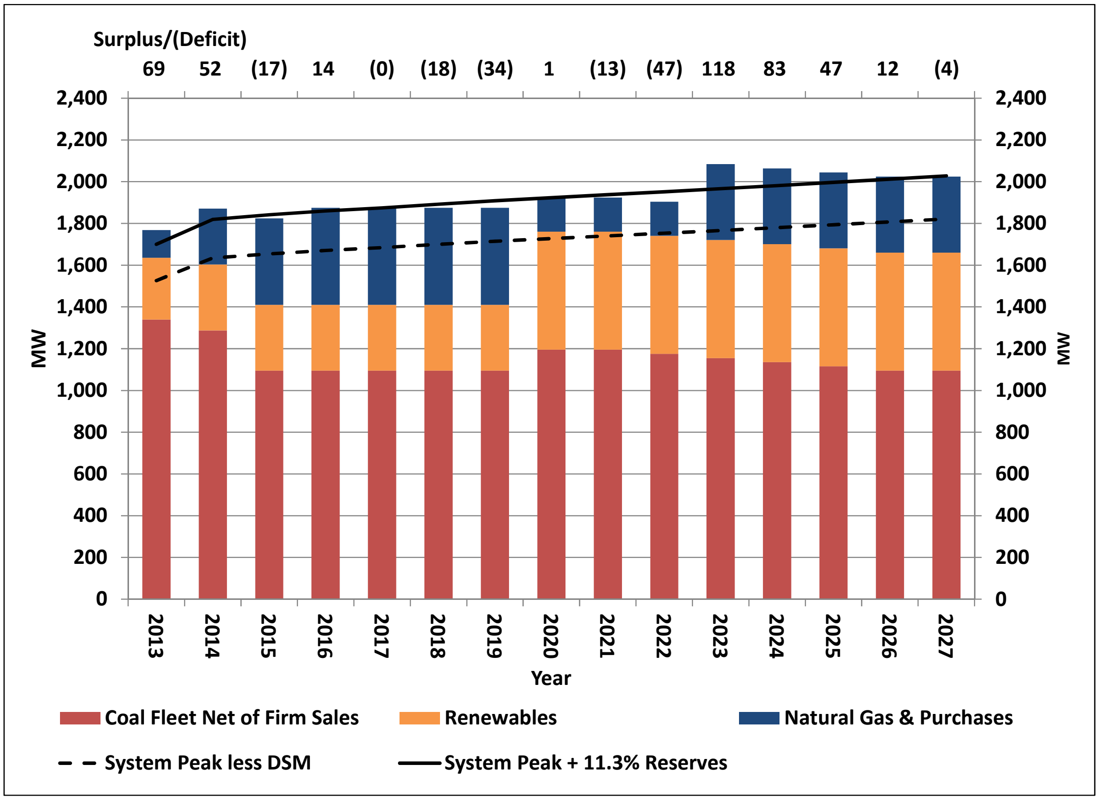


Figure 18--Preferred Plan Summer Season Capacity Outlook

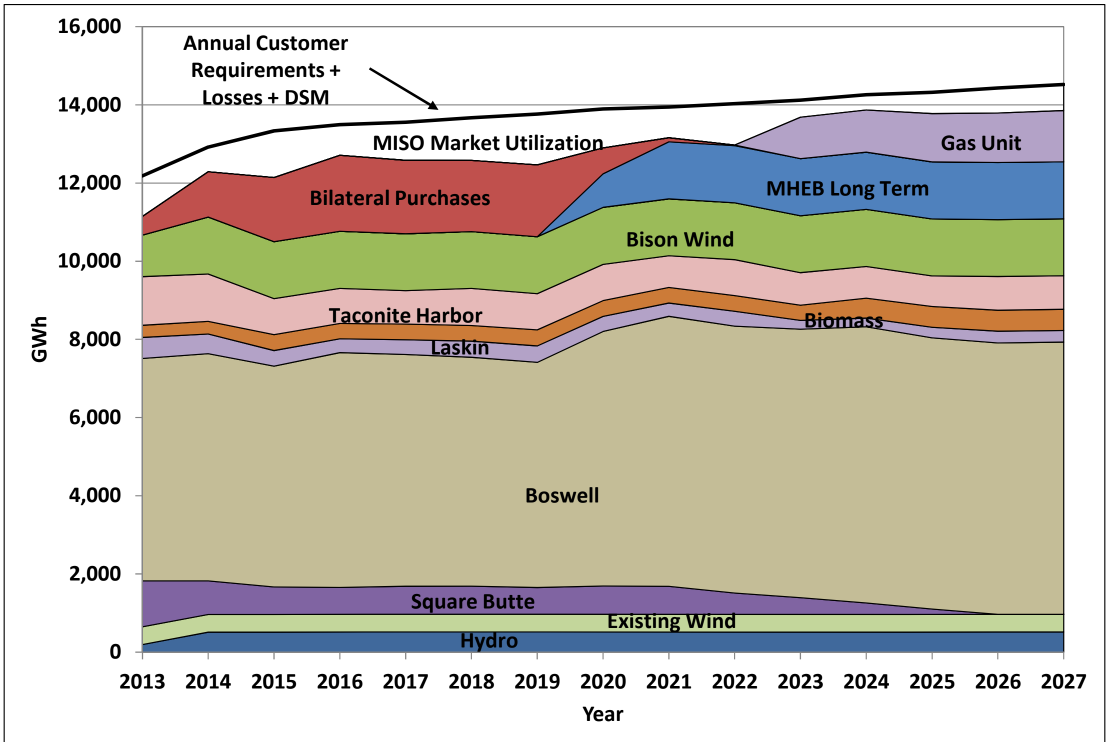


Figure 19--Preferred Plan Energy Position Outlook[49]

The Preferred Plan will add environmental benefits and help ensure rate stability for customers. The environmental compliance strategy included in the Preferred Plan to meet the upcoming MATS Rule will ensure Minnesota Power's fleet is prepared to meet the 2015 requirements in a reasonable manner for customers. Minnesota Power will achieve immense environmental reductions with the implementation of its Preferred Plan - over 75 percent reductions in overall emissions and over 80 percent for key air effluents like SO_2 and mercury (see Figure 20).

[49] This energy position represents the full capability of energy sources in Minnesota Power's Preferred Plan. Actual dispatch will vary in real time operations.

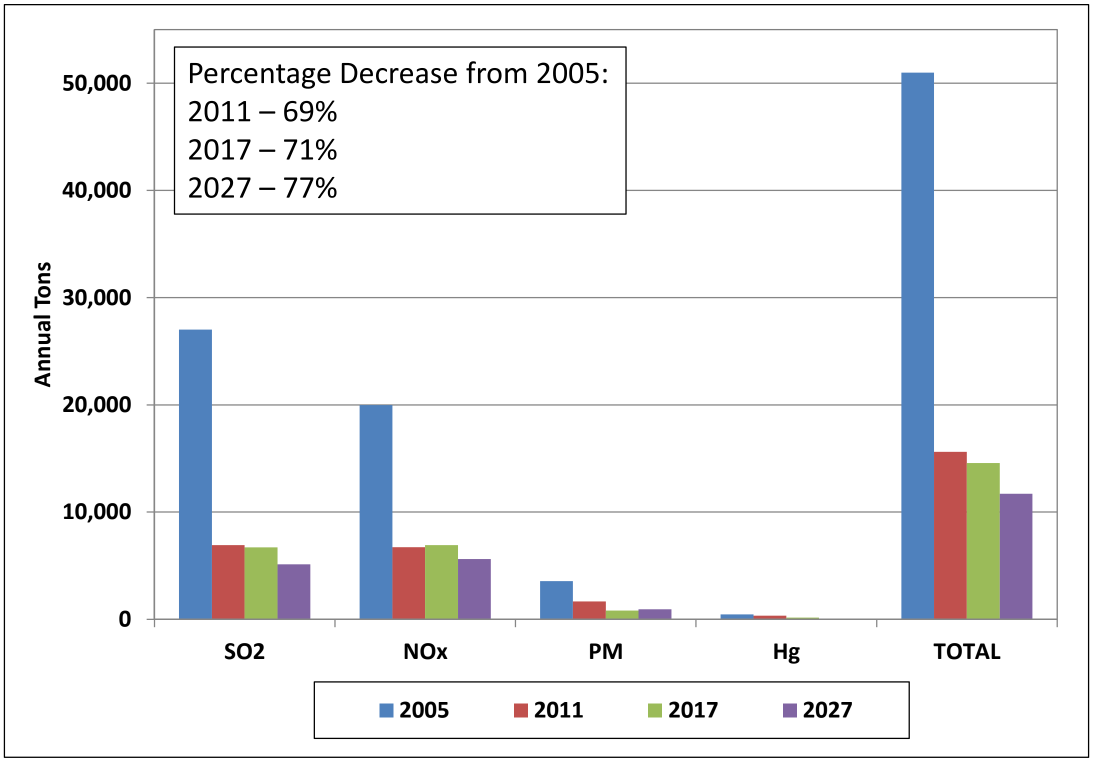


Figure 20--Emission Reductions Achieved and Projected with Preferred Plan

The most dramatic results of emission reduction will be with mercury. Minnesota Power's investment in mercury reductions since 2005 on its coal-fired facilities will contribute to Minnesota's power utilities being cited as the lowest source contributor to mercury in Minnesota by 2016.[50] Figure 21 includes the projected mercury reductions on Minnesota Power's system due to actions of its Preferred Plan.

[50] Letter dated February 11, 2013, from the Minnesota Pollution Control Agency addressing mercury emissions.

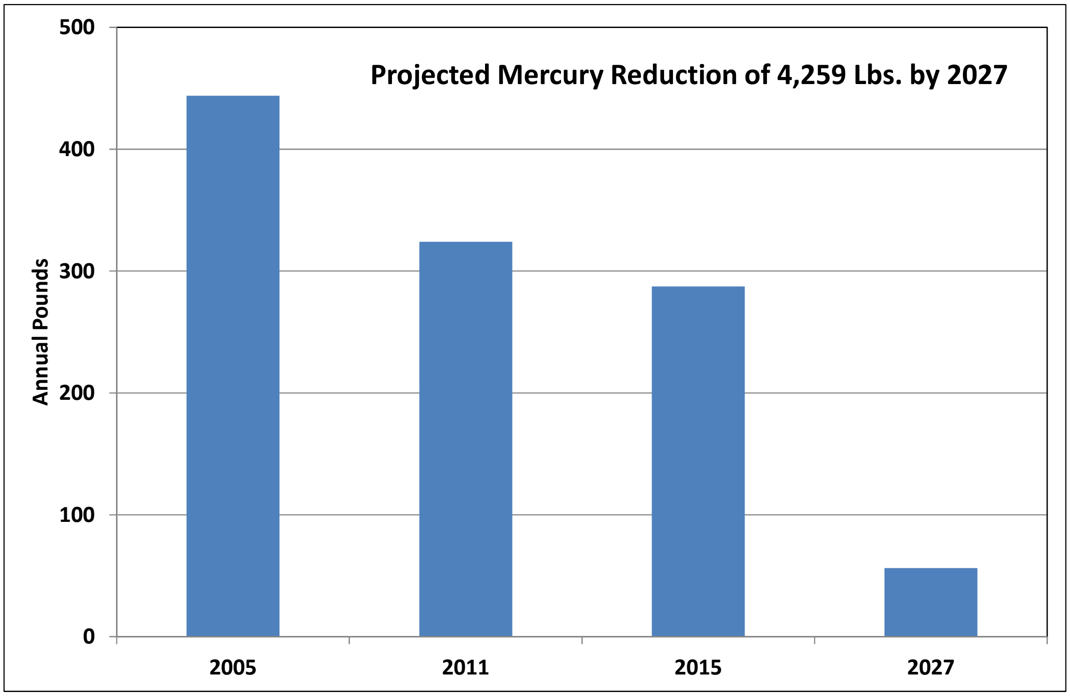


Figure 21--Mercury Emission Reductions Achieved and Projected with Preferred Plan

Minnesota Power has committed since 2005 to add only carbon-minimizing resources to its generation fleet. As load continues to grow, Minnesota Power has kept to this strategy and is continually reducing the carbon intensity of its power supply. Over 1,100 MW of generation reshaping will take place for Minnesota Power's supply portfolio by 2027: adding renewable energy such as wind (over 500 MW) and Manitoba Hydro hydroelectric power (250 MW), reducing coal-fired generation where prudent as through the phase out of its power purchase from Young 2 (227 MW), refueling LEC (110 MW) with natural gas and closing THEC3 (75 MW). This represents a significant transformation for a utility with a current peak demand of about 1,800 MW.

Figure 22 identities how the Company's Preferred Plan will help ensure its power supply is not only on track to meet the Minnesota state goals for greenhouse gas reduction, but will exceed the 2015 goal of a 15 percent reduction from 2005 levels. At the same time, Minnesota Power is planning for its largest growth in industrial customers since the late1970s. Minnesota Power remains committed to taking appropriate greenhouse gas actions as it makes its power supply decisions. To meet the long-term emission reduction goals of the state,[51] the Company will evaluate additional resource actions in the post-2020 time period as environmental regulations continue to evolve and gain clarity. Minnesota Power's cumulative resource actions, including those in the Preferred Plan, will reduce greenhouse gases by 30 percent in the 2005 to 2015 time period. This will be accomplished while concurrently serving a 20

[51] Minnesota's Next Generation Energy Act of 2007 measures set a goal for greenhouse gas emission reductions staging a 15 percent reduction in carbon dioxide equivalent emissions from all sources by 2015, 30 percent by 2025 and 80 percent by 2050 (see Minn. Stat. § 216H.02, Subd. 1).

percent increase in customer load requirements and maintaining competitive rates over the same period.

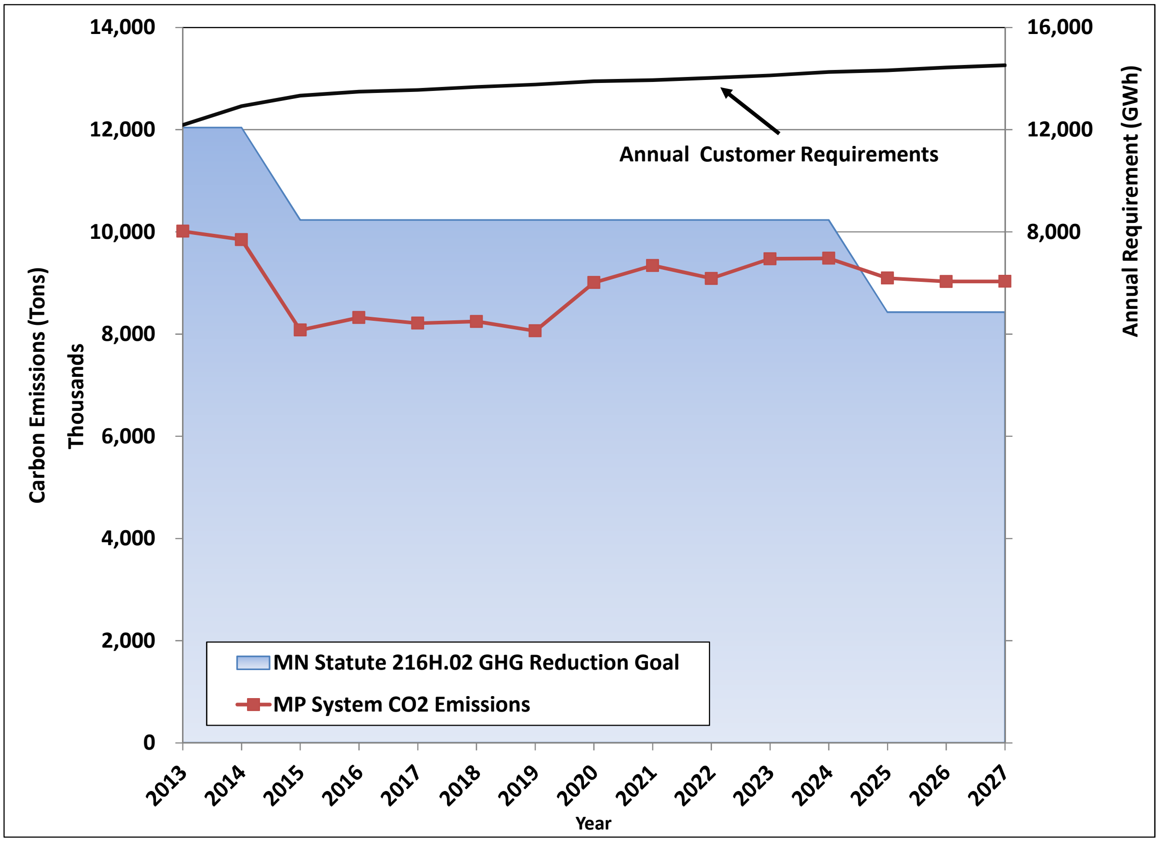


Figure 22--Greenhouse Emission Reductions Achieved with Preferred Plan

Minnesota Power was asked in Order Point 5.f. of the Commission's May 6, 2011, 2010 Plan Order[52] to include a "cost impact analysis by customer class" in its next resource plan. This analysis would help stakeholders identify how the proposed power supply actions could potentially impact their electricity costs into the future.[53] Minnesota Power worked diligently to identify the most efficient way of translating the forward-looking cost projections into an estimate for each customer class. Appendix J describes the methodology used to develop the calculations and includes projected customer cost detail for the Preferred Plan and swim lane alternatives.

For purposes of this analysis, the terms "cost impact" and "rate impact" are assumed to have the same meaning. However, the estimated rate impacts may not correspond with actual rates that the Commission sets for various rate classes in the future. In addition, numerous simplifying assumptions have been made in both the calculation methodology and the input variables, and these assumptions naturally cause imprecision in the estimates. Long-term resource planning is inherently uncertain, rather

[52] Docket E-015/RP-09-1088
[53] Minnesota Power utilized a five-year forward look for the rate impact estimation, as further projection would carry a significant level of uncertainty and be less meaningful for customers.

directional, and therefore causes additional uncertainty in these resulting rate impacts projections.

Power supply costs have inherently been increasing across the industry as new requirements and infrastructure are being incorporated. Minnesota Power has been diligent in its effort to protect affordability for its customers and has maintained some of the lowest electricity rates in the nation.[54] The Preferred Plan was evaluated to determine the potential future impact on average retail rates. The results indicate that future cost increases through 2017 would trend similar to the cost increases in its recent history. Implementation of the Preferred Plan is not indicating a dramatic shift in rates as can be the case during significant transformations. Figure 23 plots the recent average retail rates and identifies that an average 4.6 percent annual increase would be plausible if perfect ratemaking were to take place in the next five-year timeframe.

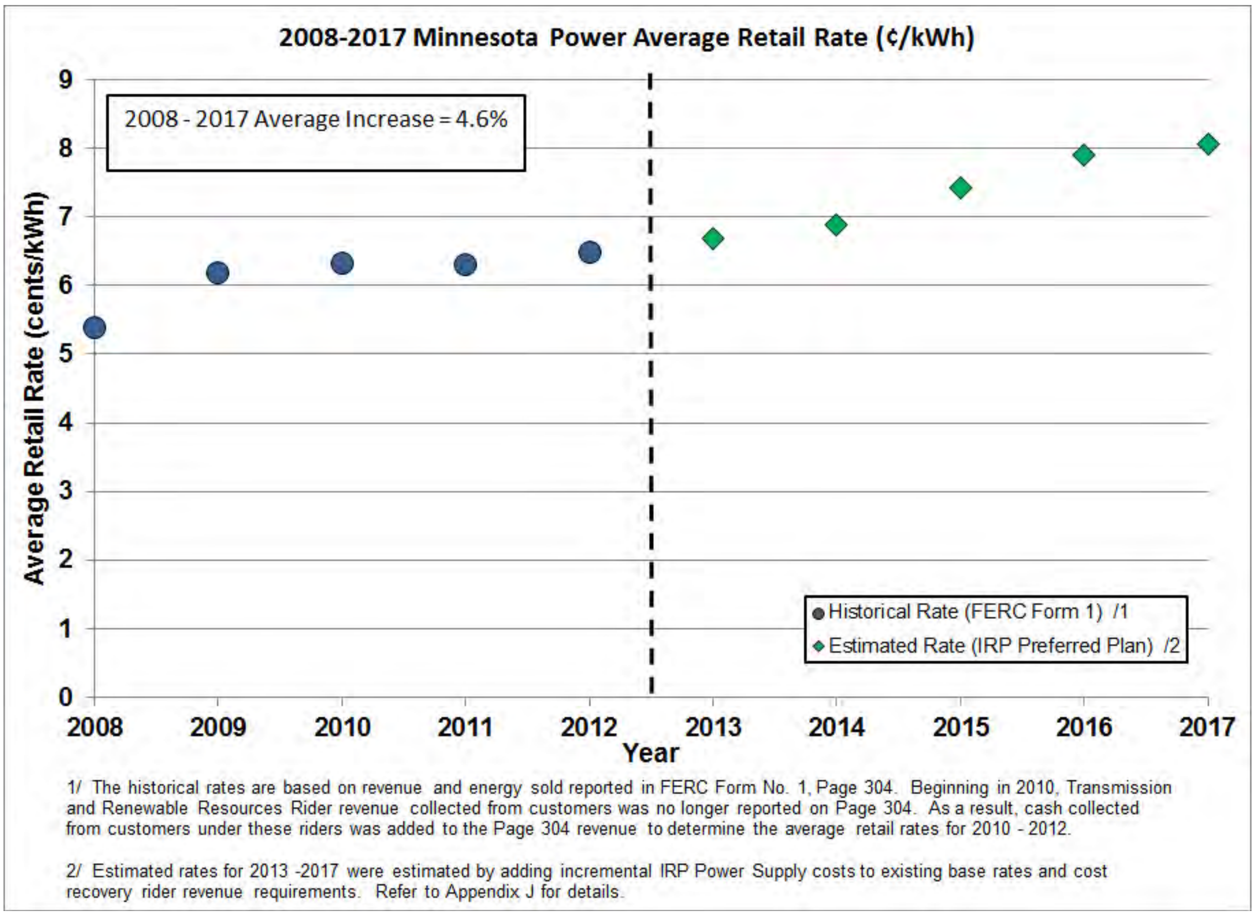


Figure 23--Average Retail Rate Recent History and Outlook with Preferred Plan

To gain more granularity and meet the intent of the Commission request, the rate impacts were estimated by customer class for the 2013-2017 time period (see

[54] Minnesota Power has most recently been noted as having the fourth lowest electricity rates out of 169 utilities by the Edison Electric Institute and second lowest in the region consisting of Iowa, Kansas, Minnesota, Missouri, North Dakota, South Dakota and Wisconsin.

Appendix J). As new resources are added as part of the Preferred Plan there are year-to-year fluctuations in costs. The resulting 2017 increases (compounded from 2013 levels) are identified in Figure 24 along with an estimate of the average customer impact per month in each class.

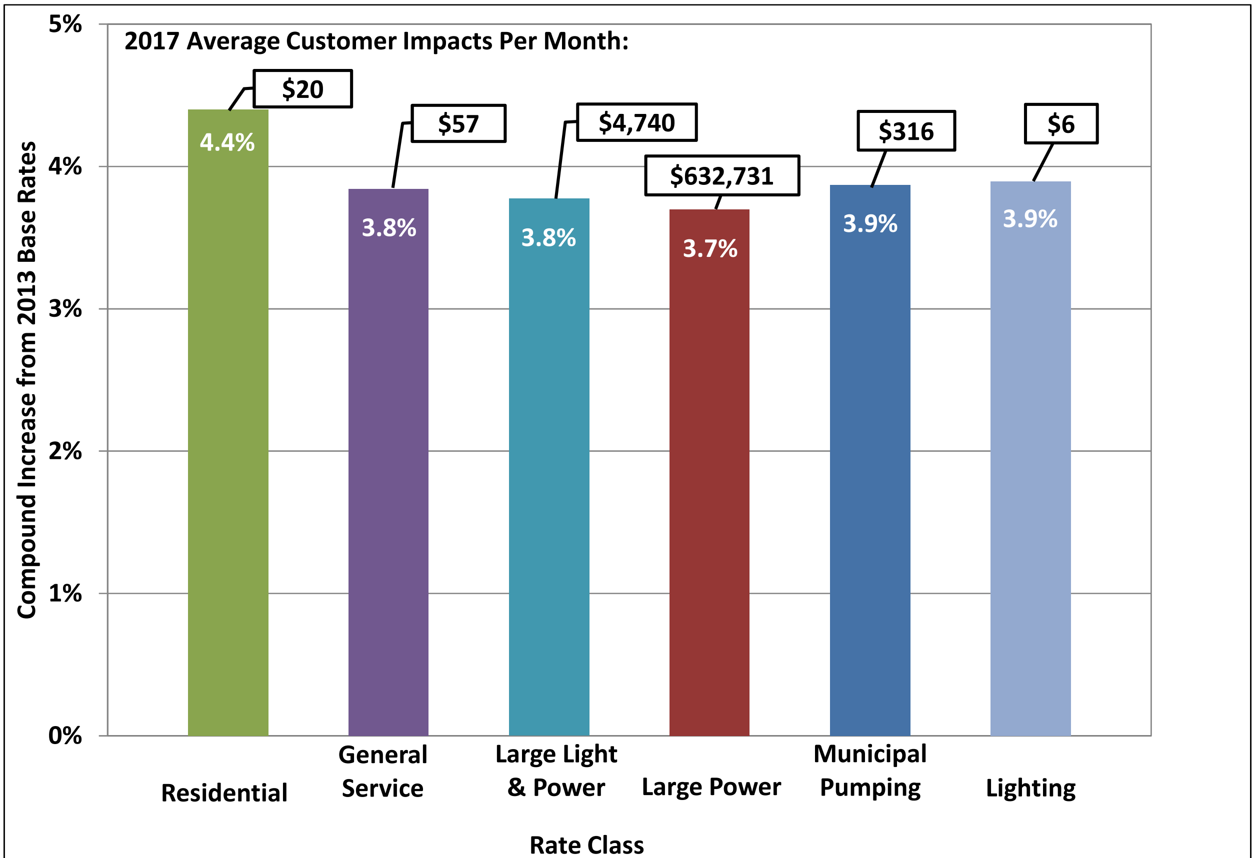


Figure 24--Estimated Rate Impact Outlook by Customer Class

Minnesota Power gained interesting insights when it incorporated the Preferred Plan under the scenario with the $21.50/ton carbon regulation penalty starting in 2017 into the rate impact evaluation. The rate impact outlook for this scenario is dramatic and immediate in 2017 for customers when the carbon regulation penalty is added. Figure 25 identifies that the average customer increase in 2017 would more than double if a carbon penalty was assumed. As identified above in Minnesota Power's expansion planning, there are almost no differences in the resource additions that Minnesota Power would make for its 2013 Plan under the carbon regulation scenario; however, there was over $1 billion in additional power supply costs under the scenario. Therefore, these cost increases, as shown by customer class in Figure 25, would be due to the burden of the additional carbon penalty on power supply costs.

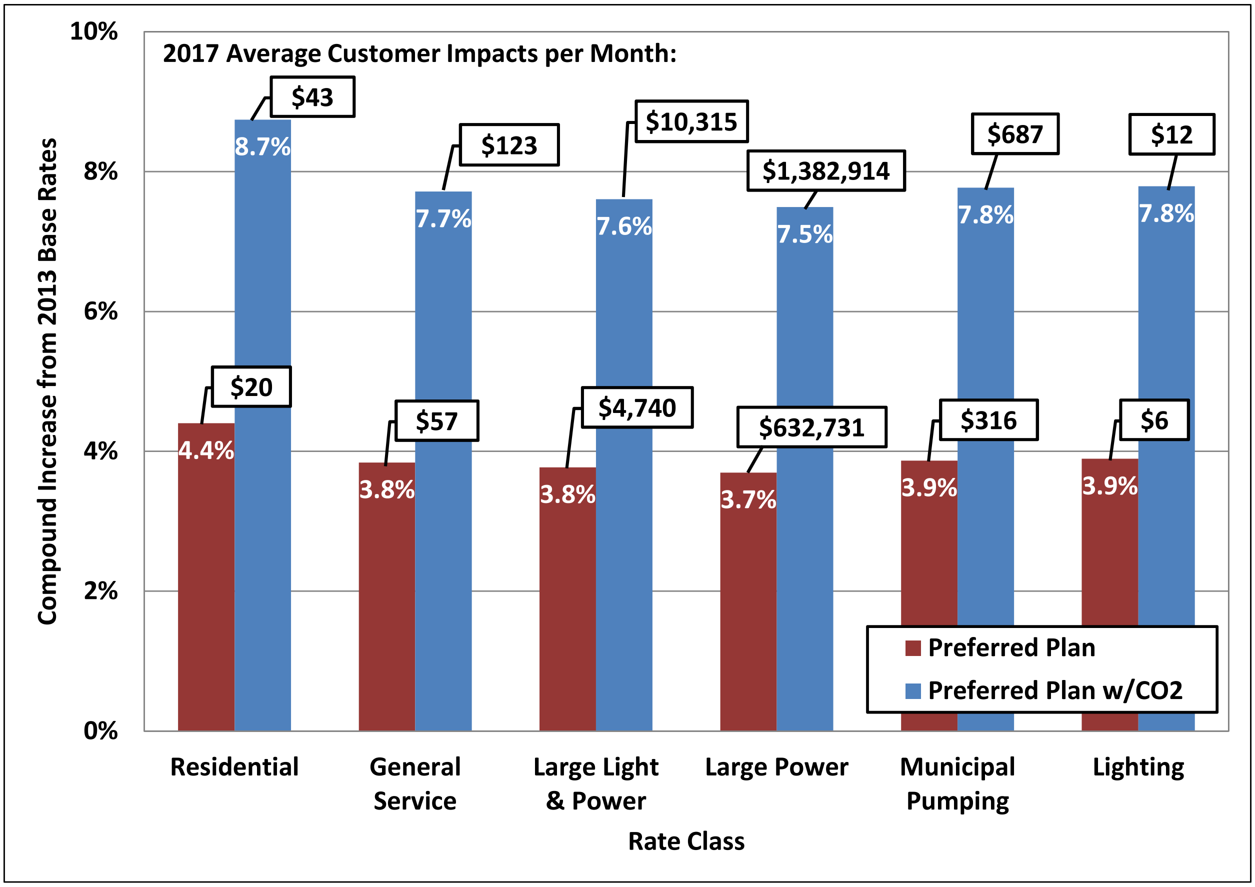


Figure 25--Estimated Rate Impact Outlook by Customer Class with Carbon Penalty

Minnesota Power continues to incorporate the power supply actions needed to reshape and transform its electric supply at reasonable customer costs. These actions are driven in part by Minnesota's RES, Conservation Improvement Plans and the Next Generation Energy Act of 2007. The actions taken to meet these standards are creating meaningful change on the power system and creating emission reductions that are outperforming even national goals (see Appendix E). At the same time, under this environment, Minnesota Power continues to carefully and prudently evaluate its system and protect affordability for customers.

The current Commission requirement to consider a carbon regulation penalty in 2017 in its resource planning evaluation is a speculative cost increase projection for Minnesota customers. Until a carbon regulation penalty is determined at the national or state level, impeding resource plans with an assumed carbon price penalty and taking premature actions that could increase costs to Minnesota electric consumers for speculative reasons without delivering commensurate environmental benefits.

V. Short-term Action Plan

Minnesota Power considered potential environmental and economic futures along with its sales forecast outlook to develop a resource plan that creates a more flexible and diverse power supply, while balancing cost, reliability and environmental impact for customers. The 2013 Plan continues the transformation of the Company's resource base by investing in renewable generation, adding natural gas to its fuels portfolio, installing more emissions-control technology at its core, coal-fired baseload generating facilities, and maintaining its strong energy conservation and DSM programs. Supported by the information and analysis in the appendices of this Plan, the resulting action plan outlined in the following sections identifies both short and long term measures that will help Minnesota Power continue to meet stakeholder needs in the near term and be poised to deliver safe and reliable service at the lowest possible cost to customers for many years.

Plans to Meet Short-term Need (2013-2017)

Minnesota Power's short-term action plan during the five-year period of 2013 through 2017 is comprised of steps that will: a) preserve competitive base load generating resources while reducing emissions, b) continue implementation of least cost demand side resources including conservation, c) reduce reliance on coal-fired generation, and d) add renewable energy and transmission infrastructure to the benefit of customers. The specific strategic and necessary actions to achieve these steps include:

1. Reducing emissions associated with converting coal energy to electricity through a series of actions that assures environmental compliance and a sound energy supply for customers. Minnesota Power has identified that LEC and THEC3 (185 MW) are not cost effective to retrofit with additional environmental controls. LEC will become a gas peaking station; THEC3 will be retired. The Company also has confirmed a robust plan to retrofit BEC4, its largest generating unit (585 MW).

2. Minimize short-term rate impacts for customers while meeting increased demand for electricity, as the northeast Minnesota economy is forecasted to grow in the next several years, by taking advantage of a lower cost power market. Minnesota Power plans to use economical, bilateral market purchases to flexibly help bridge needs in the period between 2014 and 2020, as it continues to examine its load projections and adapts to the ultimate timing of new large industrial loads on its system as well as any significant downward business cycles that may affect demand from existing large industrial customers.

3. Continue optimization of Minnesota Power's renewable energy supply. With over 400 MW of competitive wind projects already present in its portfolio, Minnesota Power is ahead of its RES requirements and is closely monitoring the need for additional intermittent renewable energy. With the extension of

the PTC, Minnesota Power will solicit a request for proposal for a minimum of 100 MW and up to 200 MW of competitive wind to be installed in the next two to three years, plans subject to maximizing the benefit of the PTC for customers.

4. Consider enhancements to selected CIP and DSM programs, while continuing to apply best practices from the conservation industry and developing leading-edge programs. Minnesota Power has maintained a strong record of conservation performance and been a state leader in meeting the Minnesota 1.5 percent energy savings conservation standard. Along with this strong dedication to conservation, Minnesota Power will continue to work to identify reasonable additions to its DSM programs where it is most beneficial for customers.

5. Prepare Minnesota Power's transmission system for the longer term addition of new power supply resources. The Company will, subject to Commission approval, begin implementation of the Great Northern Transmission Line to deliver its approved 250 MW energy purchase from Manitoba Hydro for the term 2020-2034 (a critical element of Minnesota Power's long-term action plan). The Certificate of Need will be initiated in 2013 as part of project development.

6. Complete its 2013 Load Research study Advanced Metering Infrastructure Project to better understand customer energy use, providing a robust basis for future customer conservation projects and sound rate design.

7. Execute an industrial distributed generation/renewable project at REC and continue to explore energy efficiency distributed generation projects with large customers. Additionally, Minnesota Power will develop a fair, equitable and customer-facing distributed generation program that best leverages unique customer and regional attributes to deliver valued and cost effective energy solutions for customers.

8. Continue fleet maintenance programs to sustain the economic viability, availability and reliability of Minnesota Power's generating units. A continuing Company priority throughout this planning period will be to carefully maintain its generation fleet to ensure productivity and efficiency in operation. A rigorous process is in place to sustain existing production across Minnesota Power's wind-water-wood-coal sources of energy conversion while maintaining an excellent environmental record and meeting more stringent environmental standards.

9. Continue participation in M-RETS as provide for by the Commission's October 9, 2007 Order,[55] as well as establishing a program and protocols for

[55] Docket No. E999/CI-04-1616

tradable, renewable energy credits.[56] Minnesota Power will leverage the value of renewable energy credits that the M-RETS program certifies to deliver RES compliance in Minnesota at the lowest possible cost to customers. Minnesota Power will utilize renewable energy credits generated across the years in order to optimally meet the 25 percent RES by 2025.

Three Key Contingencies

The planning process and analysis discussed in this Plan allowed Minnesota Power to consider several sensitivities that address the uncertainty that is present with the state of the economy and environmental compliance policy. Each sensitivity evaluated gave Minnesota Power the insight needed to be prepared for the potential paths each of these can take in the near term. Three key contingencies that Minnesota Power will continue to monitor and anticipated implications of these contingencies are:

1. *Extensive customer load additions or expansions do not materialize in the short term.* Minnesota Power would have excess capacity after its supply side action plan and will consider making commitments for long-term power sales to mitigate the effect of the unrealized customer load. This is made easier with Minnesota Power's plan to utilize the bilateral power market rather than a large new resource investment to optimize the power supply costs while integrating the new customer load.
2. *Carbon regulation policy implementation is expedited on a national level for existing generating resources.* Minnesota Power would accelerate its long-term actions to reduce carbon and consider the addition of new carbon minimizing generation resources and/or secure additional bilateral purchases until a resource could be placed into service.
3. *Economic recession or industry contraction.* If the recession re-emerges or key industries are forced under additional economic pressure impacting our largest customers, Minnesota Power will have significant amounts of excess capacity and will consider making commitments for power sales to mitigate the effect of the reduced customer load.

Minnesota Power will continue to closely monitor the economic and environmental control outlooks and evaluate its short-term action plan as the landscape unfolds to ensure that customers and stakeholders are served in a reliable and forward-looking way during the planning period.

[56] Docket Nos. E999/CI-04-1616 and E999/CI-03-869

VI. Long-term Action Plan

Plans to Meet Long-term Need (2018-2027)

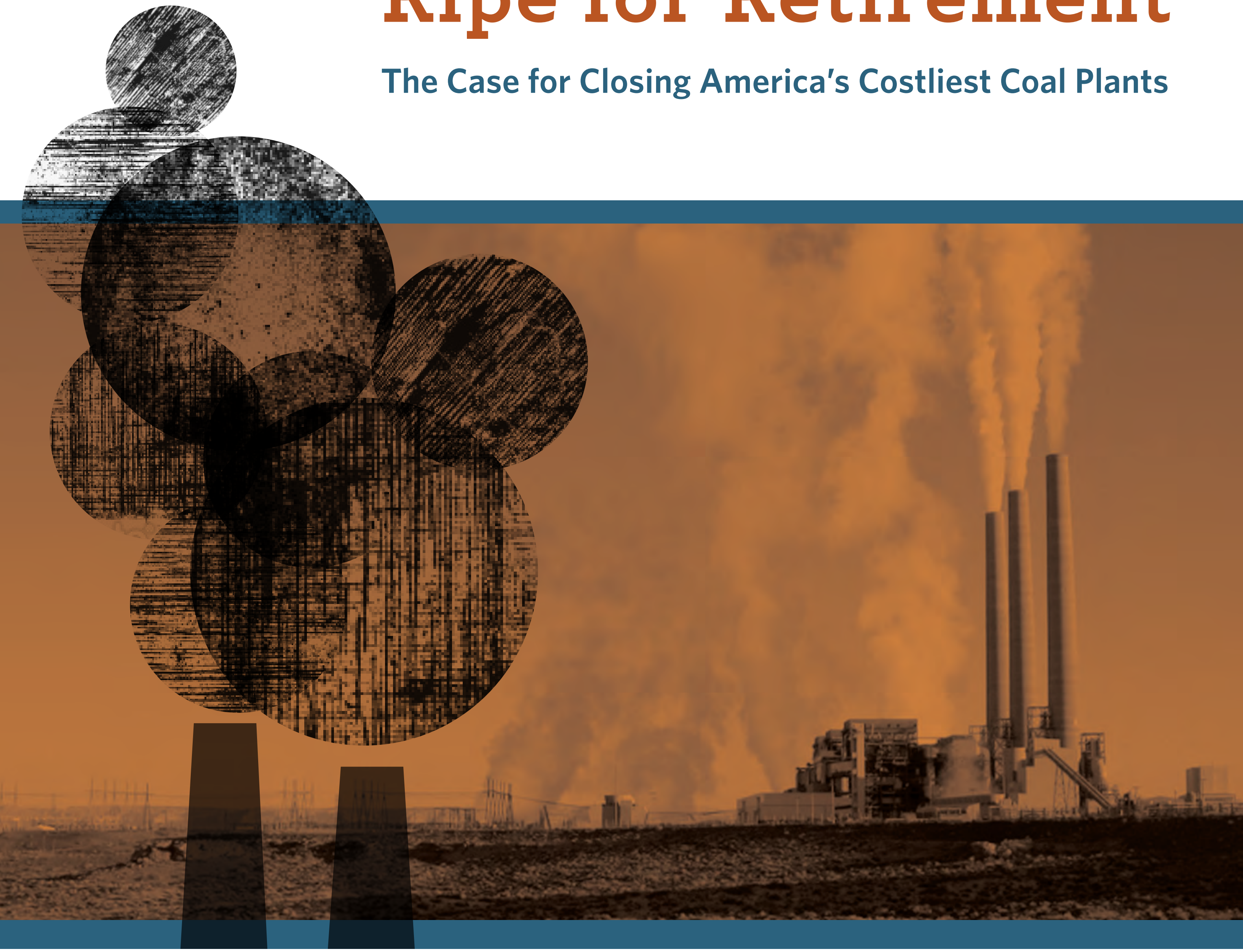
Minnesota Power will focus its long-term plan on a strategy to further reduce carbon emissions in its portfolio and diversify its generation mix towards a balance of approximately one-third renewable resources, one-third natural gas/other, and one-third efficient coal-fired generation. This long-term strategy will position Minnesota Power to be able to successfully adapt to a range of economic and environmental futures while maintaining service to its customers at a competitive cost. Each component of this long-term plan has been proven through the planning process analysis to be flexible and robust to proceed towards the Company's strategic resource goals in a variety of future scenarios. Planned components include:

1. Continue implementation of the 250 MW Manitoba Hydro PPA and Great Northern Transmission Line in the 2020 timeframe (250 MW).
2. Optimize the timing of implementing the remaining renewable projects to meet the state renewable energy standard by 2025.
3. Investigate opportunities to further diversify Minnesota Power's power supply including, further reducing reliance on coal-based generation. Minnesota Power will continue to closely assess THEC1&2 economics during this period to determine these units' competitive position within the fleet.
4. Begin investigation of an intermediate natural gas generation resource for Minnesota Power's generation fleet to meet expected capacity and energy needs in the 2020 timeframe.

APPENDIX 10

Ripe for Retirement

The Case for Closing America's Costliest Coal Plants



Union of Concerned Scientists

Citizens and Scientists for Environmental Solutions

Ripe for Retirement

The Case for Closing America's Costliest Coal Plants

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Jeff Deyette
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November 2012

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Contents

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The opinions and information expressed herein are the sole responsibility of the authors.

EXECUTIVE SUMMARY

For decades, coal has powered America. Coal mined from Wyoming to West Virginia is burned in hundreds of power plants across the United States to generate electricity. In 2011, approximately 42 percent of our nation's electricity was produced by burning coal (EIA 2012a). But today, more than three-quarters of U.S. coal-fired power plants have outlived their 30-year life span—with 17 percent being older than half a century. Most are inefficient, operating far below both their power generation potential and the most efficient coal units on the power grid.

They lack essential modern pollution controls, so they damage public health. The sulfur they emit causes acid rain. The mercury they release poisons waterways and fish and causes neurological damage in children (EPA 2012). The soot they emit creates smog that causes lung disease, premature death, and triggers asthma attacks (EPA 2010a; NRC 2010). Burning coal demands billions of gallons of cooling water from vulnerable rivers and lakes, and leaves behind vast quantities of toxic ash residuals, while coal mining causes extensive and lasting damage both to human health and the natural environment (Gentner 2010; NRC 2010). Coal-fired power plants are also our nation's largest single source of heat-trapping carbon dioxide (CO_2) emissions, the primary contributor to global warming (EIA 2012b).

These well-documented drawbacks are reason enough to reduce the nation's dependence on coal. Less widely appreciated is that many of these coal plants have reached the end of their useful life—it simply makes no economic sense to keep them running when cheaper, cleaner alternatives are available.

As of May 31, 2012, a total of 288 coal-fired generating units (a power plant comprises one or more generating units or generators) totaling 41.2 gigawatts (GW) of coal-fired generating capacity have been scheduled for closure;[1] those power generators supplied 3.8 percent of total U.S. electricity used in 2009 (the most recent year of available data). The owners of these soon-to-be-retired generators have concluded that paying for costly upgrades to keep their outdated coal plants running is a bad investment—particularly now that there are many cleaner, lower-cost alternatives that can replace old coal units while maintaining the reliability of the electric system. Whether natural gas, clean renewable energy from the wind and sun, or cost-effective efficiency measures to reduce electricity use, energy options that are abundant, cheaper, and cleaner are making it harder for dirty coal to compete.

Closing old, inefficient, and uneconomic coal plants is a historic opportunity to accelerate the transition to a cleaner energy future.

This report examines and evaluates the economic viability of our nation's remaining coal-fired electricity generating units. We find that there are many more uncompetitive coal generators that should be considered for closure. Their retirement would create an opportunity to accelerate our nation's transition to a cleaner energy future by shifting more of the electricity sector's investment dollars away from old coal plants and toward new renewable energy resources, energy-saving technologies, an expanded and modernized electric grid, and—to a more limited extent—natural gas power plants.

The Economic Test: Can America's Aging Coal Plants Compete?

To evaluate the economic competitiveness of coal generators, we compared the cost of electricity from individual coal-fired electricity generating units with the cost of electricity generated from an average natural gas power plant. Specifically, if a coal-fired generator—after installing any needed pollution controls—would be more expensive to operate than a typical cleaner-burning and more efficient natural gas combined-cycle[2]

[1] One gigawatt equals 1,000 megawatts (MW) of power generation capacity; typical coal plants range in capacity from 250 to 1,500 MW or more.

[2] NGCC plants are relatively efficient because they generate electricity not only by burning natural gas to turn a turbine but also by converting the heat from natural gas combustion into steam that powers a second electricity-generating turbine.

(NGCC) plant, then we consider that coal generator ripe for retirement. Our analysis is not an evaluation of the coal industry's compliance with federal clean air standards; instead, we estimate the cost of modernizing the coal fleet to protect public health by installing the most effective pollution control technologies available.[3]

UCS identified up to 353 coal generators in 31 states—totaling 59 GW of power generation capacity—that are ripe for retirement.

Many older NGCC plants have already largely paid off their capital costs, whereas other newer plants are still recovering their initial investment. Thus, we calculated a range for the total capacity of coal generation considered ripe for retirement. The high end of that range was defined by comparing the operating costs of a coal generator—assuming it was upgraded with modern pollution controls—to the operating costs of a typical existing NGCC plant whose capital costs were already largely recovered. This comparison of coal generating units to existing NGCC plants yielded the greatest number of uneconomic coal generators that could be retired; this we call our Ripe for Retirement high estimate.

The low end of our range was defined by comparing the operating costs of a coal generator—again, assuming it was upgraded with modern pollution controls—with the operating costs of a typical *new* NGCC plant whose capital costs were not yet recovered. This comparison of coal generating units to *new* NGCC plants yielded the fewest uneconomic coal generators that could be retired; this we call our Ripe for Retirement low estimate.

In both the high and low estimates, the costs of pollution controls were added to the costs of individual coal-fired generators as needed so that the economic analysis included the cost of controlling four major air pollutants: sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM, or soot), and mercury (detailed methodology appears in Appendix A). These costs were then compared with the operating costs of the NGCC plants.

We also examined the effect of several variables that could influence the economic competitiveness of the remaining operational coal fleet. In these alternative scenarios, we compared the operating costs of a coal generator upgraded with added pollution controls with NGCC plants using a higher and lower natural gas price, and with the cost of new wind projects both with and without federal tax credits. Lastly, we examined how a $15-per-ton price on carbon emissions would affect the economic viability of coal-fired power compared with cleaner alternatives.

Why a comparison with NGCC plants to establish a range to our estimates? In many parts of the country, natural gas is currently the most readily available low-cost power generation option capable of rapidly replacing coal-fired power plants in the near term, and many utilities are already taking steps to make this switch. However, we believe that retiring coal capacity could and should be replaced by a mix of alternatives including renewable energy technologies and reduced demand due to energy efficiency. We did not consider new nuclear or coal with carbon capture and storage (CCS) plants as near-term alternatives because of their long construction lead times, high costs, and limited number of proposed projects. The closure of old, inefficient, and uneconomic coal plants is a historic and important opportunity not only to make smart economic investments, but also to transition to the lowest-carbon energy resources to reduce global warming emissions significantly from the power sector.

The Ripe-for-Retirement Generators

Using our economic criteria, we find that a significant number of additional coal generators nationwide are ripe for retirement, ranging from a low estimate of 153 to a high estimate of 353. Collectively, the units represent 16.4 to 59.0 GW of generating capacity; they thus supplied 1.7 to 6.3 percent of total U.S. electricity used in 2009. Notably, the units we identify are in

[3] For every coal generator that lacks pollution controls for any of four specific pollutants—sulfur dioxide, nitrogen oxides, particulate matter, and mercury—we calculate the cost to install that control technology.

Key Findings

- Using economic criteria, we have identified a range of 153 to 353 coal-fired electric utility generating units (from a national total of 1,169) as ripe for retirement; all are good candidates for closure because they are economically uncompetitive compared with cleaner, more affordable energy sources. These coal units collectively represent 16.4 to 59.0 GW of generation capacity and 1.7 to 6.3 percent of total U.S. electricity used in 2009 (the most recent year of available data).
- The potential closure of these units would be in addition to the 288 units representing 41.2 GW of coal-fired generating capacity already scheduled by their owners for closure, which produced 3.8 percent of U.S. electricity use in 2009. Together, the ripe-for-retirement units plus the already announced closures would constitute a combined 100.2 GW of potential coal plant retirements.
- Like the announced retirements, the coal generators that are ripe for retirement are typically older, less utilized, and dirtier than the rest of the nation's coal fleet.
- The ripe-for-retirement generators can be closed without jeopardizing the reliability of the national electricity system because the United States is projected to have 145 GW of excess capacity by 2014 above and beyond reserve margins required to maintain reliability at the regional power grid level.
- Every region of the country has the potential to replace the generation from the ripe-for-retirement generators by increasing the use of renewable energy, implementing energy efficiency to reduce electricity demand, and ramping up underused natural gas plants.
- The states with the most ripe-for-retirement generators are primarily in the Southeast and Midwest, with the top five (in order) being Georgia, Alabama, Tennessee, Florida, and Michigan.
- The ripe-for-retirement generators are owned by some of the nation's largest power companies, with the top five (in order) being Southern Company, the Tennessee Valley Authority, Duke Energy, American Electric Power Company, and First Energy.
- Replacing a combined 100.2 GW of coal generators could reduce heat-trapping CO_2 emissions and provide other significant public health and environmental benefits. Emissions could be cut by anywhere from 245 million tons to 410 million tons annually, depending on what resource replaces the coal. These reductions account for 9.8 to 16.4 percent of CO_2 emissions from the power sector in 2010.

addition to the 288 coal units previously announced for retirement by utility companies and power generators, which supplied 41.2 GW or 3.8 percent of the nation's electricity.

For all of the ripe-for-retirement generators identified in this report, the power they produce—after being upgraded with modern pollution controls—is more costly than electricity generated from existing natural gas power plants, and many are more expensive than wind power. Our analysis shows that many of these ripe-for-retirement units may already be uneconomic even *before* considering the cost of pollution controls. Indeed, even without considering the cost of needed pollution controls, 23.4 GW are *already* more expensive to operate than existing natural gas plants.

It is no coincidence that the ripe-for-retirement coal generators may be good candidates for closure.

Ripe-for-retirement coal generators are older, less utilized, and dirtier than the rest of the nation's coal fleet.

Table ES-1. Older, Underutilized, and Dirtier: Ripe-for-Retirement Coal Generators Are Similar to Those Already Announced for Retirement

	Announced Retirements	Ripe-for-Retirement Generators	
		High Estimate	Low Estimate
Number of coal generators	288	353	153
Total capacity[a] (gigawatts)	41.2	59	16.4
Percent of total U.S. electricity consumption	3.8%	6.3%	1.7%
Average generator age (years)[b]	50	45	45
Average generator capacity factor[c]	44%	47%	47%
Average generator size (megawatts)	143	167	107
Percent of generators lacking three or more pollution control technologies[d]	88%	71%	83%
Avoided annual CO_2 emissions if all identified generators are retired (million tons)[e]	88–150	157–260	52–75

[a] Capacity is the amount of electricity a coal generator (or group of generators) can produce operating at full (100%) power. One gigawatt is equal to 1,000 megawatts.

[b] Age is as of 2012. Results reflect average of the age of the units, weighted by each unit's total potential generation capacity.

[c] Capacity factor is as of 2009 (the most recent year of available complete data), which measures how often and intensively a generator is run over time, calculated as the ratio of actual power output to potential output if the generator had operated at full (100%) capacity over the same period. Results reflect weighted averages based on total generating capacity.

[d] Pollution control technologies evaluated include scrubbers (for sulfur dioxide), selective catalytic reduction (for nitrogen oxides), baghouses (for particulate matter), and activated carbon injection (for mercury).

[e] The low end of the avoided annual CO_2 emissions range reflects replacement of coal with natural gas (existing NGCC units for the high estimate and announced retirements, new NGCC units for the low estimate); the high end of the avoided annual CO_2 emissions range reflects replacement of coal with zero-carbon-emitting resources such as wind, or reduced energy demand due to increased energy efficiency.

As Table ES-1 indicates, the coal units we identified are, on average, similar to the coal generators that utilities have already scheduled for closure according to three important metrics:

They are old. Ripe-for-retirement units average 45 years in age, close to the 50-year-old average of the generators recently announced for retirement. Both figures are well beyond the 30-year expected life span for a typical coal generator. Old coal generators are typically less efficient and have higher operating costs compared with newer plants.

They are not heavily used. Ripe-for-retirement generators are underutilized because they are not the workhorses of the electricity industry: they operate at an average of just 47 percent of their power generation capacity, compared with an average of 64 percent for the total U.S. coal fleet. The generators already slated for closure have a similarly low average capacity factor of 44 percent. Conversely, a large, recently built coal unit typically operates at approximately 80 to 85 percent of its design capacity.

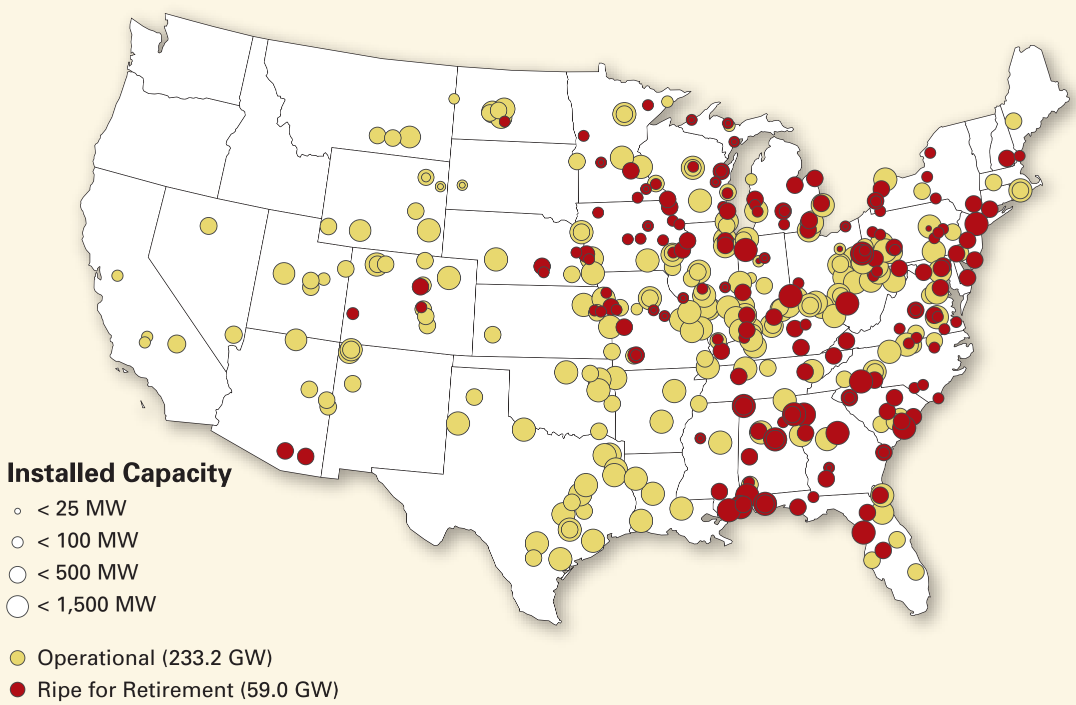
Nearly 40 percent of ripe-for-retirement coal units are more expensive to operate than existing natural gas plants—before considering the cost of needed pollution controls.

They are dirty. More than 70 percent of the generators identified as ripe for retirement in our analysis lack at least three of the four major pollution control technologies used to reduce the environmental and health effects of coal-fired power generation. The same is true of 88 percent of the units already scheduled to be shut down.

As Figure ES-1 indicates, the nation's coal-fired generators are concentrated in the eastern half of the country, primarily in the Southeast, Midwest, and Mid-Atlantic. Those areas have been dependent on coal for many decades, with many plants built a half-century ago, so it is not surprising that they also host the largest concentration of plants that are ripe for retirement. In general, coal plants in the western United States tend to be younger and more likely to have pollution controls installed.

Our analysis found that 19 states are each home to more than one gigawatt of coal generating capacity whose power costs exceed those of existing NGCC plants (Figure ES-2, p. 6, and Table 3 in Chapter 3) and are thus ripe for retirement. Four of the top five states are in the Southeast—Georgia, Alabama, Tennessee, and Florida (in order of capacity that is ripe for retirement)—with 79 generating units totaling more than 21.6 GW. Although Michigan ranks fifth in capacity, it has the greatest number of coal generators ripe for retirement: 39 mostly smaller units averaging 94 MW each. Elsewhere in the Midwest, Wisconsin, Indiana, and Ohio are also among the top states, with 7.1 GW of coal capacity spread over 50 generators that are uneconomic when compared with existing natural gas plants.

Figure ES-1. Ripe-for-Retirement Generators Located in 31 States (High Estimate by Size of Generators: 353 Generators Totaling 59 GW*)



As many as 353 coal generators in 31 states are ripe for retirement (red dots) according to our high estimate, which compares the cost of operating coal-fired generating units with the cost of operating existing NGCC generating plants. These 353 units total 59 GW of capacity, about 6.3 percent of electricity generated nationwide.

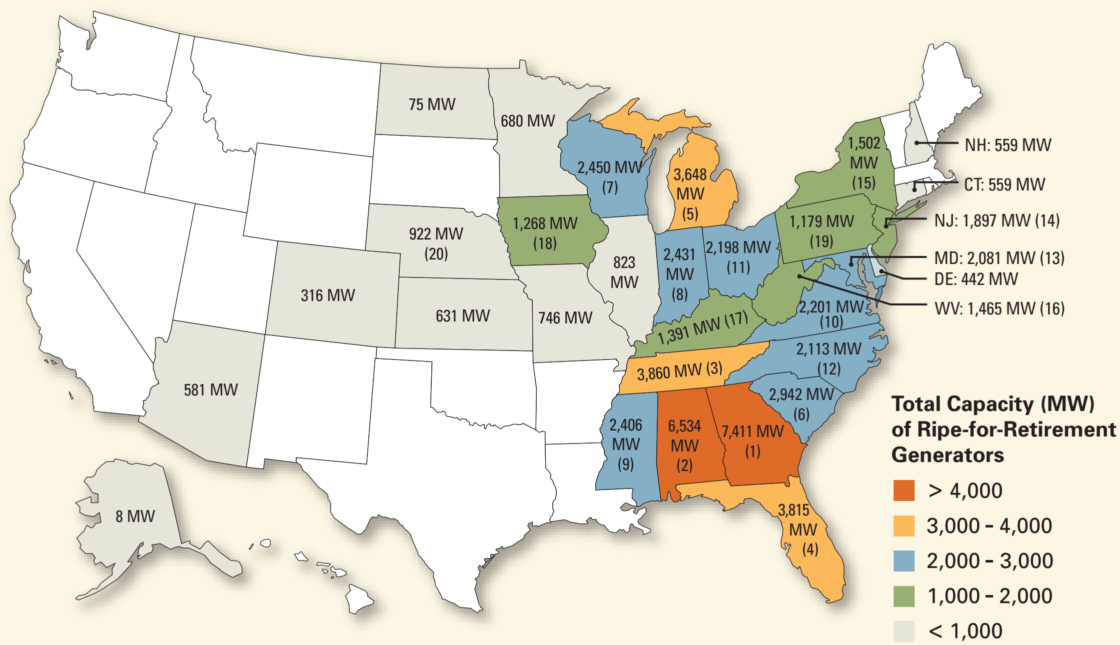
* Includes all utility-scale generating units using coal as a primary fuel source, except those that have already been announced for retirement. Each dot represents an individual generator (some dots represent multiple generators at the same power plant); the size of the dot depicts its generating capacity. Capacity is the amount of power a generator is capable of producing when operating at full (100%) output, typically measured in megawatts or gigawatts (1 gigawatt = 1,000 megawatts). A gigawatt of coal generating capacity is capable of producing enough electricity to power approximately 1 million typical U.S. homes.

The ripe-for-retirement generators are owned by dozens of different utilities and independent power producers. Some owners have been less forthcoming than others in scheduling the closure of economically uncompetitive coal units. Southern Company, for instance, has by far the most generation capacity deemed ripe for retirement—15.6 GW—but it has announced less than 1.4 GW of plant closures (Table ES-2). Duke Energy, American Electric Power, and FirstEnergy, by contrast, have fewer plants deemed ripe for retirement, in part because these companies have already announced plans to close a larger portion of their coal fleet.

Economic Variables

A variety of factors will determine the future economic viability of the nation's coal fleet relative to other electricity sources. Such factors include the price of coal relative to alternatives such as natural gas and renewable energy, the cost of complying with existing and

Figure ES-2. Ripe-for-Retirement Generating Capacity Is Concentrated in Eastern States* (High Estimate: 59 GW)



UCS identified up to 353 coal-fired generators nationwide that are uneconomic compared with cleaner alternatives and are therefore ripe for retirement. These units are in addition to 288 coal generators that utilities have already announced will be retired. Under the high estimate, there are 19 states with more than 1,000 MW of ripe-for-retirement coal-fired generating capacity, all in the eastern half of the United States. Georgia leads all states with more than 7,400 MW of ripe-for-retirement capacity; several other Southeast states also top the list. However, if previously announced retirements were added to the high estimate, the state rankings would shift. For example, several Midwest states would move up in rank as a result of significant recent coal retirement announcements. As a result of nearly 6,800 MW in announced retirements—more than any other state—Ohio tops the rankings in total coal-fired generating capacity both scheduled for retirement and ripe for retirement.

* Rankings for top 20 states are given in parentheses. State totals of ripe-for-retirement coal capacity do not include announced retirements.

pending pollution standards, and whether a price is placed on carbon dioxide. As our analysis shows, wind is already cost-competitive with coal and natural gas in some parts of the country. With additional policy support such as tax incentives, considerably more wind and solar energy facilities could compete with existing coal plants, particularly given the environmental and health costs that coal or utility companies do not shoulder but are borne by the public.

To assess how economic variables would alter the number of coal generators deemed ripe for retirement, we repeated our analysis under the following additional potential future scenarios: both a 25 percent increase and a 25 percent decrease in the price of natural gas from our core-case price of \$4.88/MMBtu;[4] a \$15 per ton price on CO_2 emissions, which is consistent with more conservative price forecasts from several government, industry, and expert analyses (Johnston et al. 2011); and both the extension and expiration of federal tax credits for wind power (Figure ES-3, p. 8). The core-case natural gas price is a national 20-year levelized price delivered to the electricity sector based

Table ES-2. Top 10 Power Companies with Most Ripe-for-Retirement Generators (High Estimate)

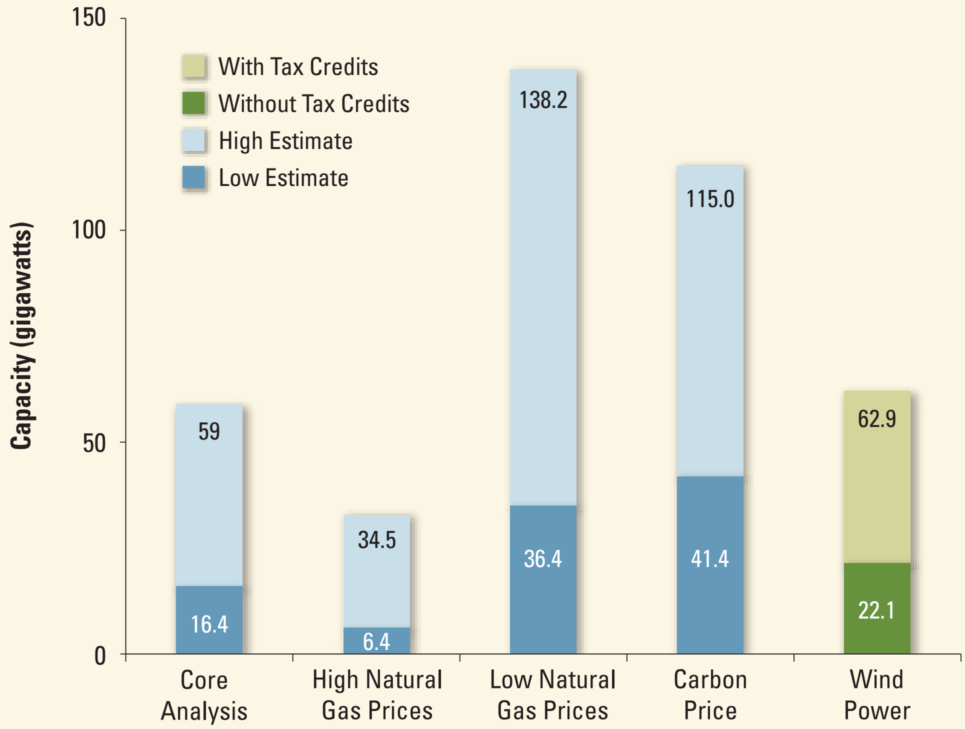
Rank	Power Company	Ripe-for-Retirement Generators			Capacity of Announced Retirements (MW)
		Capacity (MW)	Number of Generators	Location (State)	
1	Southern Company	15,648	48	Alabama, Florida, Georgia, Mississippi	1,350
2	Tennessee Valley Authority	5,385	28	Alabama, Kentucky, Tennessee	969
3	Duke Energy Corp.	2,760	17	Indiana, North Carolina	3,230
4	American Electric Power Company, Inc.	2,355	4	Indiana, Virginia, West Virginia	5,846
5	FirstEnergy Corp.	2,075	7	Ohio, Pennsylvania	3,721
6	Public Service Enterprise Group Inc.	1,713	4	Connecticut, New Jersey	0
7	Progress Energy, Inc.	1,685	3	Florida, South Carolina	2,532
8	Wisconsin Energy Corp.	1,653	10	Michigan, Wisconsin	384
9	SCANA Corp.	1,405	3	South Carolina	883
10	GenOn Energy, Inc.	1,385	6	Maryland, West Virginia	3,882

[4] One million British thermal units (MMBtu, a unit of measure of the energy content of fuel) is equivalent to 1,000 cubic feet of natural gas.

on the U.S. Energy Information Administration's (EIA's) reference case projections from its *Annual Energy Outlook 2012* (EIA 2012c). The low-price case, which is a 25 percent decrease in the EIA's reference case projections, leads to a natural gas price of $3.66/MMBtu. The high-price case, which is a 25 percent increase, leads to a natural gas price of $6.10/MMBtu.

In comparing this set of alternative scenarios we find that varying the natural gas price has the most dramatic effect on how many coal units are deemed uncompetitive. Wind power with a continuation of existing federal tax credits has a similar level of impact on the economic viability of coal generators as does the high estimate in our core case of comparing the operating costs of coal generators with the operating costs of existing natural gas plants. Placing a price on carbon dioxide emissions would also have a significant impact on the economics of coal generators. It is important

Figure ES-3. Coal Generating Capacity Deemed Ripe for Retirement under Alternative Scenarios



Our analysis reveals that low natural gas prices and a price on carbon dioxide have the greatest impact in expanding the pool of coal-fired generators deemed ripe for retirement, and that extending the federal tax credits for wind power is also significant. Alternative scenarios explore three external economic factors that could influence the coal-fired generating capacity deemed ripe for retirement. In the core analysis (far left), the low estimate (dark blue alone) compares the operating cost of coal generators with the operating cost of a new NGCC plant; the high estimate (combined dark blue and light blue) compares the operating cost of coal generators with the operating cost of existing NGCC plants. The middle three bars repeat the analysis for hypothetical scenarios where natural gas prices might be 25 percent higher or 25 percent lower, or where a $15/ton price might be put on carbon dioxide emissions. For the wind power scenario (far right), the analysis illustrates the capacity of coal-fired generators deemed ripe for retirement if federal tax credits for wind power are allowed to expire (dark green) or are extended (combined dark green and light green).

to note, however, that although these comparisons set analytical bounds on our analysis, they do not prescribe which energy resources should in fact replace coal.

This report attempts to characterize which coal generators are most economically vulnerable under current and possible near-term economic and regulatory conditions in the power market. It can help utilities, state and federal regulators, and banks decide whether it makes more economic sense to retire certain coal-fired generators, and potentially replace them with cleaner energy alternatives, instead of sinking hundreds of millions—and in some cases billions—of dollars in additional capital into retrofitting them with modern pollution controls.

We recognize that factors other than operating costs can and will influence which coal generators are retired. Such factors include whether the coal units are located in regulated or deregulated electricity markets, which can greatly influence whether power plant owners can pass coal plant upgrade costs on to ratepayers. Other key factors include where the coal units are located on the power grid, what cleaner alternative energy sources are available nearby, and whether power transmission lines are available to deliver those cleaner alternatives to customers. The trend, however, is clear: collectively, these factors are leading to an accelerated retirement of coal generating capacity in the United States.

A Boon for Public Health

Retiring many or all of the coal units identified as ripe for retirement within this decade would improve public health by cutting the amount of dangerous pollution that coal-fired power plants emit into the air we breathe and water we drink, including sulfur dioxide, nitrogen oxides, particulate matter, mercury, and other toxic substances. Such pollutants have been linked to numerous health problems including aggravated asthma attacks, breathing problems, neurological damage, heart attacks, and cancer. Moreover, closing those plants would cut emissions of carbon dioxide, the principal contributor to global warming, and reduce the risks of heat stress and ozone pollution, which are both linked to higher temperatures, among other health-related concerns (EPA 2012; CATF 2010; EPA 2010a; Gentner 2010; NRC 2010; Trasande, Landrigan, and Schechter 2005).

A wholesale switch to natural gas is not a long-term solution to the climate problem: natural gas is cleaner-burning than coal but still leads to significant carbon dioxide emissions.

Basing our assessment on the 2009 emissions profiles for all 353 coal generators in our high estimate, shutting down all the ripe-for-retirement coal generators could annually avoid approximately 1.3 million tons of SO_2 and 300,000 tons of NO_x emissions, as well as significant amounts of mercury, particulates, and other toxic emissions—depending on the emissions profile of the power resources that replace them. Replacing 100.2 GW of coal generators (the total sum of the 41.2 GW of announced retirements plus the additional 59 GW of ripe-for-retirement generators) by ramping up existing natural gas facilities (many of which are underutilized) would reduce annual carbon dioxide emissions from power generation by approximately 245 million tons—equivalent to 9.8 percent of U.S. power sector CO_2 emissions in 2010. Carbon dioxide emissions at the plant level would be substantially reduced because new natural gas power plants emit about 40 percent of the carbon dioxide that existing coal-fired plants do per unit of electricity produced (EIA 2012c; EIA 2011a). Even bigger reductions could be realized if all 100.2 GW of coal generators were replaced entirely with wind power and other zero-emissions sources, and energy demand were reduced due to greater energy efficiency. In that case, CO_2 emissions could be cut by 410 million tons annually—equal to a 16.4 percent reduction in 2010 U.S. power sector global warming emissions.

A Reliable Transition

While we rely on the economics of natural gas facilities for comparison with coal in our analysis, we are not suggesting that retiring coal generators should simply be replaced with natural gas—they should be replaced by a mix of cleaner energy resources (including wind, solar, geothermal, and biomass) in addition to natural gas. Moreover, some of the reduction in coal generation would not need to be replaced at all if states put in place measures that reduce electricity demand (through energy efficiency, for example). Investments in new transmission lines could be targeted to bring renewable energy to market. Investments in advanced energy technologies that better balance supply and demand, and integrate large amounts of variable resources into the electricity grid, could also help enable a smooth transition to a low-carbon energy future in the long run.

Increased electricity supply from natural gas could come from two sources: greater use of the nation's abundant and underutilized existing natural gas generation capacity, and the development of a limited number of new natural gas power plants. The nation's natural gas power plant fleet operated at only 39 percent of its design capacity in 2010. The amount of additional electricity that could be generated by running these plants at 85 percent capacity would exceed the amount (100.2 GW) of electricity generated by all coal generators already announced for retirement plus all 353 additional generators we deem ripe for retirement in our high estimate. Indeed, the power supply would be adequate in every region of the country (Figure ES-4), although a more detailed analysis of the electricity grid would be needed to identify potential supply and demand imbalances that could result from coal-unit retirement. In addition, analysis of natural gas pipeline capacity would be needed to determine the adequacy of pipeline infrastructure to support increased natural gas generation. But the abundance of underutilized *already existing* natural gas generating capacity across the country suggests that any need for replacement generating capacity would not be a barrier to retiring coal units in most areas.

Over the next eight years (that is, by 2020), we project that existing state policies requiring the use of renewable electricity and energy-saving technologies will generate or save more electricity than would be lost (100 GW) through the closure of retired coal generators (UCS 2012). Such clean energy gains would exceed the amount of power generated in 2009 by these coal units in most regions of the country, as shown in Figure ES-4.

Retired coal generation should be replaced by a mix of cleaner energy resources, including wind, solar, geothermal, and biomass in addition to natural gas.

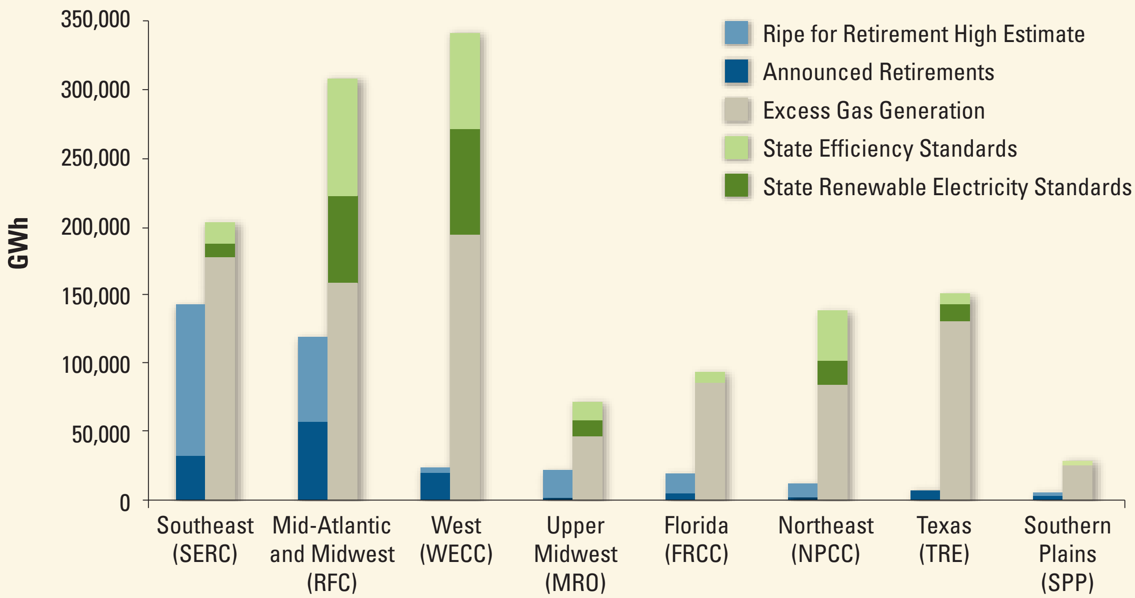
Our Clean Energy Future

Apart from the uneconomic coal-fired generating capacity that is already planned for shutdown or ripe for retirement based on current economic considerations, we need to consider the long-term implications of continuing to operate the remaining 229 GW of coal-fired generation capacity that still appears economically viable in the short term. The stark reality is that avoiding the worst effects of climate change requires profound and aggressive action to decarbonize our power sector, and rapidly. Many studies have demonstrated that a smooth transition to low-carbon or carbon-free sources of energy is technically feasible and can be affordable, given stable and supportive long-term clean energy and climate policies (e.g., Specker 2010; UCS 2009).

While the current policy landscape is challenging, the risks of unchecked climate change are becoming ever clearer. Policy makers should consider the significant health and economic risks of unchecked climate change and take broad action to cut carbon dioxide emissions, which could include putting a price on carbon dioxide pollution. With this future cost in mind, making expensive investments to upgrade the remaining coal fleet with needed pollution controls is financially risky, as it may simply be postponing the inevitable: these newer coal plants will also eventually need to be shut down (or retrofitted with very expensive, and as yet untested, carbon dioxide capture and sequestration technology) to meet climate policy goals. Cleaner, low- or no-carbon energy sources are far better long-term investments.

A wholesale switch to natural gas is not a sustainable solution to the climate crisis. Although cleaner-burning than coal and with less than half the carbon content, natural gas is still a fossil fuel; burning it

Figure ES-4. Renewable Energy, Energy Efficiency, and Existing Excess Natural Gas Can Readily Replace Retiring Coal Generation by 2020*



Old, inefficient coal-fired generators deemed ripe for retirement can be shut down with minimal impact on the reliability of the nation's electricity grid. Every region of the country has the potential to replace the generation from both announced retirements (dark blue) plus units we identify as being ripe for retirement (medium blue). They can do so through a combination of ramping up underused natural gas plants (gray), and making use of new renewable energy generation (dark green) and energy efficiency savings (light green) that are projected to be developed over the next eight years as a result of existing policy requirements, including existing state-level renewable electricity standards and energy efficiency resource standards.

* The North American Electric Reliability Corporation (NERC) oversees reliability for a bulk power system that includes the United States and Canada. In this effort, NERC coordinates with eight regional entities to maintain and improve the reliability of the power system. These entities are composed of utilities, federal power agencies, rural cooperatives, independent power marketers, and end-use customers. Excess gas generation was estimated by determining the amount of generation that would be produced if existing gas facilities increased electricity production to 85 percent of their capacity. State efficiency standards and renewable electricity standards are the GWh of savings or generation that would occur if state policy goals are met through 2020.

still leads to significant emissions of carbon dioxide. Moreover, natural gas itself (mainly composed of methane) is a far more powerful global warming gas than carbon dioxide, and methane leakage associated with drilling, processing, and transporting natural gas raises its life-cycle global warming emissions. Drilling practices such as hydraulic fracturing also lead to significant environmental and health concerns, such as the potential contamination of drinking water supplies.

Thus, investments in renewable energy and reducing electricity demand through greater efficiency, supported by sustained federal and state policies, will be critical to transitioning to a low-carbon electric system over time.

Recommendations

In states with a large number of economically vulnerable coal generators, the closure of ripe-for-retirement units presents a historic opportunity to accelerate a transition to a clean energy economy that will improve environmental quality, reduce carbon dioxide emissions, protect public health, and create new jobs.

National and state policies and regulations have a crucial role in promoting and supporting a transition to a clean energy economy.

Clean air standards. The Environmental Protection Agency (EPA) has already finalized strong standards for several harmful pollutants from coal-fired plants, including NO_x, SO_2, mercury, and other toxic pollutants. It is also expected to finalize, for both new and existing power plants, standards for carbon dioxide emissions, coal ash disposal, and wastewater and cooling-water intake structures—and should implement them without delay to level the playing field for cleaner generation sources and reduce investment uncertainty. These standards will require plant owners to install pollution control technologies at many conventional coal plants that will significantly reduce their harmful impacts to the environment and public health. Plants where upgrades are not economic may then be shut down. Power plant owners may also choose to shift generation to cleaner sources that are able to comply with the standards. The EPA has already signaled that it will use existing flexibilities in the Clean Air Act to ensure that power plant operators have reasonable time to comply with the EPA's standards, and that it will coordinate closely with the Federal Energy Regulatory Commission (FERC) and regional reliability authorities to ensure that the implementation of the standards has minimal effect on the reliability of the electric system.

Energy efficiency and renewable electricity standards. Twenty-nine states have already adopted renewable electricity standards requiring utilities to gradually increase their use of renewable energy, and 27 states have established targets for energy savings achieved through investments in energy efficiency (UCS 2012; ACEEE 2011). Those states can accelerate the transition from coal by strengthening such standards. Other states that have not yet implemented such policies should take the lead from the forward-thinking majority of the nation and enact similar provisions. Even more effective would be a strong federal standard that sets minimum national targets for renewable energy and energy savings—although states should not wait for the federal government to act. In addition, Congress should extend by at least four years federal incentives for renewable energy and energy efficiency, including the federal production tax credit (PTC) for wind power and other renewable sources. Congress should also reduce federal incentives for fossil fuels and nuclear power, as these mature technologies have already received enormous subsidies for decades that continue to give these unsustainable resources an unfair market advantage.

By 2020, existing state policies requiring the use of renewable electricity and energy-saving technologies will generate or save more electricity than would be lost by closing ripe-for-retirement coal plants.

Electric system planning. Transmission planning entities such as regional transmission organizations (RTOs) and independent system operators (ISOs) that operate large sections of the nation's power grid are uniquely positioned to help shape our clean energy future, assuming they function in an inclusive and transparent manner. Utilities and transmission planning authorities should make public their analyses about what transmission system improvements or additions to the energy resource mix may be needed when coal-fired power plants shut down. In addition, transmission planning authorities must fully comply with FERC Order 1000, which requires all transmission planning entities to consider all relevant state and federal clean energy policies and pollution standards when determining what mix of infrastructure investments will be needed to meet projected customer demand while maintaining reliability. Likewise, regulators in traditionally regulated cost-of-service states should require the utilities they regulate to conduct system-wide planning that evaluates all available alternatives to meet electricity needs in their state, including energy efficiency and clean energy technologies. State regulators should allow a utility to recover the cost of pollution controls from ratepayers only if the utility has demonstrated that the public interest could not be better served by retiring the coal plant and replacing it with more affordable clean energy alternatives. In deregulated states, merchant power producers, who may not be able to recoup an investment in expensive pollution controls in competitive wholesale power markets, are already finding that the bankers who finance investments to retrofit old coal plants are increasingly skeptical about whether such capital investments are financially prudent.

State regulators should not allow a utility to recover the cost of pollution controls from ratepayers if a coal plant can instead be retired and replaced with more affordable clean energy alternatives.

Renewable energy and efficiency as the primary replacement for coal. Historically low natural gas prices and a lack of steady federal policy support for renewable energy and energy efficiency could result in natural gas replacing much of the retiring coal capacity. Simply shifting our reliance on coal to a new reliance on natural gas would be a huge missed opportunity to transition the electric system to truly low- or no-carbon resources that have less impact on the environment and public health. Deliberate policy support at the federal, state, and regional levels is needed to ensure that renewable energy and energy efficiency are not crowded out by a hasty, risky, uncontained rush to natural gas.

Near-term policies are only the beginning of the journey toward achieving a clean, sustainable energy system that will protect public health and achieve the reductions in carbon dioxide necessary to avoid global warming's worst consequences. The nation can and must expand these and other policies to ensure that we achieve these emissions reductions at the lowest possible cost and with the greatest benefits to society. Closing coal plants that are ripe for retirement and replacing them with cleaner, low-cost alternatives, particularly with renewable energy and reduced energy demand through energy efficiency, is a good start.

CHAPTER 1

Introduction: Pulling the Plug on Uneconomic Coal Plants

In the spring of 2009, executives at Public Service of New Hampshire (PSNH) had a choice: clean up or shut down the utility's 52-year-old Merrimack Station power plant. Reducing the plant's harmful emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), fine particles (soot), mercury, and other pollutants as required by state law would mean spending hundreds of millions of dollars to install modern pollution controls. The controls would have many public health and environmental benefits such as reducing acid rain, smog, lung cancer, asthma, and diseases caused by mercury. But, as a coalition of businesses, ratepayers, and nonprofit groups[5] argued, greater benefits could be achieved at a lower cost by retiring the plant and replacing it with cleaner and cheaper power (Hirschberg 2009).

Despite arguments to the contrary, the leaders of PSNH, which provides power to more than 500,000 homes and businesses, opted to retrofit the plant. Three years and $422 million later, emissions from Merrimack Station's smokestack are cleaner, but the plant still emits far more mercury and climate-warming carbon dioxide (CO_2) than would any non-coal alternative (Northeast Utilities 2012). The plant also has not been running much. In February 2012, PSNH announced that it expected to idle Merrimack Station for months at a time over the course of the year because it costs the utility substantially more to run the plant than to buy electricity from cleaner-burning natural gas power plants elsewhere in New England (Loder 2012).

Unfortunately, the utility's customers will be reimbursing PSNH for its costly retrofit of Merrimack Station through their electricity bills for many years—even when the plant does not run. That is because, as with many publicly regulated utilities across the country, PSNH was able to raise power rates to pass the full cost of the pollution controls on to its ratepayers.

Today, the owners of hundreds of coal-fired power plants across the United States face a similar choice of whether to retrofit or retire their dirty, decades-old, economically uncompetitive plants. Much is at stake, including huge costs to ratepayers, additional decades of mercury emissions and associated harm to public health and the environment, hundreds of millions of tons of avoidable carbon dioxide emissions, and the continued environmental impacts of coal extraction, processing, transportation, and disposal. Also at stake are missed opportunities to invest in cleaner and more affordable technologies, including renewable energy sources (such as wind power), greater efficiency that reduces energy demand, and even natural gas.

Owners of coal-fired power plants must choose whether to retrofit or retire their dirty, decades-old, economically uncompetitive plants.

In this report, we present the results of an economic analysis that identifies the old, inefficient, and economically marginal coal generators nationwide that deserve particularly rigorous scrutiny before their owners commit to—and regulators agree to—spending huge sums of utility ratepayer money or investor funds to upgrade them. For each coal-fired generating unit (for definition, see box, p. 16) that produces power for the U.S. electric system, we estimated the cost of upgrading the unit with four commonly used pollution controls. Then we compared the cost of continuing to operate the unit with the pollution controls with the cost of generating electricity from two cleaner and readily available sources: natural gas and wind. What we found is that, in hundreds of instances, the economics of old coal generators are indefensible. For at least 353 coal-fired generators—nearly a third of those across the nation—it would be less expensive to build and operate a new array of wind turbines than it would be to retrofit and run these old coal units.

[5] The Union of Concerned Scientists was among the groups urging regulators and the utility to consider retiring the plant rather than retrofitting it.

For nearly a third of coal-fired generators across the nation it would be less expensive to build and operate new wind turbines than it would be to retrofit and run these old coal units.

One factor in the declining competitiveness of coal-fired power plants is that coal itself has become more expensive. The average cost per ton of coal delivered to U.S. electric utilities has increased each year since 2002, even after adjusting for inflation (EIA 2012a).[6] Rising international demand, particularly from China and India, is pushing domestic coal prices higher and is already creating extreme uncertainty in global coal markets, according to the International Energy Agency (IEA 2011). The United States is increasingly exposed to international coal markets: coal exports more than doubled from 2006 to 2011, reaching the highest levels since 1991 (Brown 2012).

The burden coal places on human health and environmental quality is also a major liability. Emissions of SO_2, NO_X, and fine soot particles from coal plants cause more than 13,000 premature deaths annually and 20,000 additional heart attacks in the United States, imposing an estimated $100 billion in annual adverse health effects (CATF 2010). Coal-burning power plants are the source of at least half of the nation's human-caused emissions of mercury, a known neurotoxin that can impair brain development (EPA 2012). Coal mining operations level mountaintops and pollute streams. The ash left over after coal is burned contains highly toxic and persistent poisons that must be handled carefully and at great expense to avoid contaminating waterways and aquifers. These and other public health

Coal-fired Generation: An Introduction

Nearly all coal-fired power plants in the United States burn coal to heat water in a boiler that creates high-pressure steam. The steam turns a turbine, which drives an electrical generator. A power plant may be composed of multiple steam boilers driving multiple generators. In this report, we analyze coal-fired power at the generator, or "unit," level and use those terms interchangeably.

Definition of Terms

Boiler: An enclosed vessel (containing water or another liquid) that converts heat from a furnace into steam.

Turbine: A machine that converts steam generated in the boiler into mechanical power (a rotating series of blades connected to a central shaft) and is connected to a generator.

Generator: A device that converts the mechanical energy of a spinning turbine into electrical energy. Generators are rated by the maximum number of watts of electrical power they can produce.

Unit: The power production components of a power plant, comprised of a generator and the turbine and steam loop that drive it. Many power plants have multiple units that can be operated independently.

Watt: The standard unit of electric power. A typical compact fluorescent lightbulb uses 15 to 20 watts, while a hair dryer might use 1,500 watts.

Megawatt (MW): 1 million watts.

Gigawatt (GW): 1 billion watts, or 1,000 megawatts.

Kilowatt-hour (kWh): The typical unit used to measure the amount of electricity used by consumers (households and businesses), equal to 1,000 watts used in one hour.

Megawatt-hour (MWh): 1 million watt-hours or 1,000 kilowatt-hours.

Gigawatt-hour (GWh): 1 billion watt-hours or 1,000 megawatt-hours.

[6] The cost of transporting coal from the mine to the coal plant, typically by rail or barge, varies by coal type. Appalachian coal, while relatively expensive to mine, is cheaper to transport than Wyoming coal, which is cheaper to mine but more expensive to transport, because Appalachian mines are generally closer to the coal plants they serve.

and environmental problems have prompted a variety of state and federal regulations that require coal-plant owners to install pollution control equipment—although hundreds of plants have yet to be cleaned up.

Further, coal plants face the substantial financial risks associated with their status as the nation's top source of the carbon emissions that are disrupting the climate and raising temperatures around the globe. As clarified in a 2007 Supreme Court ruling and the subsequent endangerment finding issued by the Environmental Protection Agency (EPA) in 2009,[7] the agency has the authority and the obligation under the Clean Air Act to regulate these emissions (Massachusetts v. Environmental Protection Agency, 549 U.S. 497(2007)). The agency has recently proposed rules governing carbon emissions from new coal plants, and limitations on emissions from existing plants are in the regulatory pipeline. As the severity of climate change becomes increasingly apparent, policy makers will be under growing pressure to enact more aggressive policies to cut coal-generator carbon emissions.

With all these drawbacks, coal's dominance in the U.S. electricity sector has been eroding and will likely continue to do so. Coal's share of domestic electricity generation fell from 56 percent in 1990 (EIA 1996) to 52 percent in 2000 and 42.2 percent in 2011 (EIA 2012a), a trend the U.S. Department of Energy's Energy Information Administration (EIA) expects to continue. Planning for new coal plants is at a virtual standstill (EIA 2011b). As coal declines, new and increasingly competitive renewable energy and natural gas installations have been making up the difference; the electric industry is projecting major expansions of those cleaner technologies in the next five years (NERC 2011).

Next to such technologically advanced, fast-growing lower-carbon alternatives, the nation's coal fleet looks decidedly over-the-hill. More than three-quarters of U.S. coal generating units (262 gigawatts, or GW, of the nation's 344 GW), as measured by their power generation capacity, have exceeded their expected life span of 30 years, and 41 percent are more than 40 years old (Figure 1, p. 18).

With natural gas prices near historic lows, costs of renewable energy technologies continuing to fall, and investments in energy efficiency slowing the growth of electricity demand, many utilities and independent power providers are determining that spending money to keep old, inefficient coal generators running makes no economic sense. Closures totaling 41.2 GW—12 percent of the U.S. coal fleet—have been announced since 2009.

More than three-quarters of U.S. coal generating units have exceeded their expected 30-year life span.

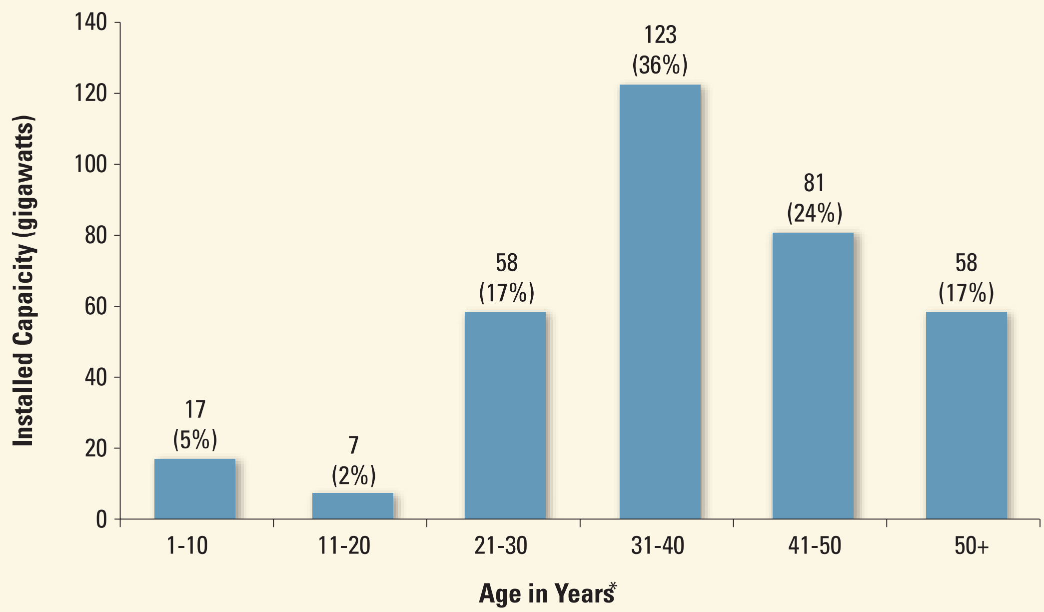
In dozens of other cases, however, plant owners appear ready to choose the same costly path taken by PSNH's executives at Merrimack Station.

This report demonstrates why power plant owners must take a hard look at whether that course makes economic sense for them—or for the customers they serve—before they install pollution controls that would effectively extend the life of old coal plants by decades, but only at the expense of investing potentially billions of dollars. Pressure from state public utility commissions, elected officials, and the general public can force coal plant owners to reconsider spending money on an old coal generator and instead invest in cleaner, more sustainable power options.

Chapter 2 examines the common characteristics of the current slate of retiring coal generators. It also explains the analytical methods we used to identify additional coal generators with similar common characteristics that are uneconomic, and that we therefore deem ripe for retirement. Chapter 3 presents the results of that analysis: how many ripe-for-retirement generators there are, why we deemed them economically uncompetitive, where they are located, what characteristics they have in common, how much electricity they generate, and how much carbon dioxide and other pollutants they emit. In Chapter 4, we show why the orderly retirement of most or all of these coal generators likely would cause no significant shortfalls in electricity supplies, thanks to the current abundance of unused natural gas generation capacity plus the

[7] The endangerment finding was strongly reaffirmed in a 2012 decision by the U.S. Court of Appeals for the District of Columbia Circuit, which said the EPA's "interpretation of the … Clean Air Act provisions is unambiguously correct."

Figure 1. Age of U.S. Coal Generators in 2012, by Capacity



Today's U.S. coal fleet is advanced in age, with 262 GW or 77 percent of total capacity already exceeding the normal 30-year life expectancy. Seventeen percent of the coal fleet was brought online before 1962 (more than 50 years ago).

*Percent of total U.S. coal fleet in parentheses.

expected growth in natural gas, renewable energy, and energy efficiency in the coming years. Finally, in Chapter 5, we recommend policies at the state, regional, and federal levels that would facilitate the transition from coal to these cleaner alternatives.

How the Grid Works: A Simplified View

The electricity grid has been called the world's most complex machine. It connects generators, or sources of power, to consumers in homes, offices, factories, and schools through thousands of miles of transmission wires. The generators must supply exactly as much electricity as consumers demand every second of every day as cities wake up and return to sleep, large factories and consumer appliances switch on and off, and generators and transmission lines are placed into and out of service.

Large baseload generating stations such as nuclear and coal power plants typically operate 80 percent to 90 percent of the time because they are expensive to build but relatively cheap to run. Intermediate or cycling plants, which are more expensive to run but also more flexible than baseload plants, are turned up or down to follow hourly changes in demand. Peaking plants, which are typically cheap to build but expensive to run, are used only to meet maximum daily or seasonal demand, such as on hot summer days. While natural gas power plants can be operated as baseload plants, they are more frequently used as intermediate and peaking plants because they can be ramped up and down very quickly.

Some renewable energy technologies, such as hydroelectric, bioenergy, geothermal, landfill gas, and concentrating solar power plants with thermal storage, can be operated as baseload or intermediate generation just like fossil fuel (coal, oil, and natural gas) and nuclear plants. Electricity from variable renewable energy sources, such as wind and solar power, generally is used whenever it is available; it has very low operating costs because the "fuel" (the wind and the sunlight) is free. Energy-saving strategies that can affect customers' electricity demand enable grid operators to manage electricity use and costs by reducing power consumption particularly during high demand and peak pricing periods. Such demand-side measures include efficiency, conservation, and demand-response programs, which can control a customer's demand for power in response to market prices and/or system conditions.

Grid operators, also called balancing authorities, balance energy demand and the generating and transmission resources available within a control area. The grid operators signal to power plants in a control area whether to increase or decrease their power output as needed. As electricity demand increases, power plants are generally turned on, or dispatched, in order of increasing cost or prices the plant operator bids into the power market. When operating or transmission constraints emerge, some plants may be dispatched out of economic or market order so as to maintain power grid reliability. The last generator that is "turned on" to meet demand at a particular location and time sets the price for the rest of the market.

Automatic generation control (frequency regulation) fine-tunes generating output to respond to changes in demand over seconds and minutes, while spinning reserves (plants in operation but not "connected" to the grid) must be ready to respond within minutes to an hour if needed. Cycling and peaking plants respond to hourly changes in demand. The system must maintain an operating reserve at least large enough to replace the sudden loss of the biggest resource on the system, whether it is a generating plant or a transmission line. Finally, system operators must maintain an annual reserve margin sufficient to meet the forecast peak demand, plus an added percentage to cover for unexpected demands or plant outages.

CHAPTER 2
What Makes a Coal Generator Ripe for Retirement?

Economics typically drive the decision either to upgrade and continue operating a coal generator or to retire it. Based on this premise, our analysis evaluates the economic competitiveness of the generators in the operational coal fleet, and identifies the ones that are most ripe for addition to the growing list of plants already slated to retire. We do so by answering one simple question for each coal generator in the United States: When modernized with current pollution control technologies, does the coal generator produce power at a cost that is competitive with cleaner alternatives? If the answer is no—meaning that it is more expensive to retrofit and continue operating the coal generator than it is to switch to a cleaner energy source—then we consider it ripe for retirement.

Of course, other factors also influence the economic viability of coal generators. Some of these factors we were able to evaluate, such as the volatility of natural gas prices and potential policies to reduce carbon dioxide emissions. However, we did not evaluate other factors, including reliability constraints, the availability and proximity of alternative resources, the costs of upgrading cooling-water intakes and coal ash disposal systems to modern standards, or the increasing maintenance costs and performance problems associated with aging generators. While some of these unevaluated factors could lead plant owners to continue operating specific coal generators, on balance, we believe they are weighted toward a more conservative estimate of uneconomic units.

This chapter describes our methodology for assessing the characteristics of the coal generators already scheduled for retirement and evaluating the economic competitiveness of the remaining units in the nation's coal fleet (for a detailed description of our methodology, including data sources and cost assumptions, see Appendix A). The analysis included the following four key steps:

When modernized with current pollution control technologies, does the coal generator produce power at a cost that is competitive with cleaner alternatives?

Current operating costs. We first calculated the current operating costs of each coal generator and identified several important factors that contribute to higher operating costs.

Pollution control technology and costs. We then identified which coal generators are currently lacking key pollution control technologies to reduce emissions of sulfur dioxide, nitrogen oxides, particulate matter, mercury, and other toxic air pollution, and calculated the costs of installing such controls on each generator.

Comparing coal against cleaner energy sources. Next, we compared the costs of operating each coal generator with—and without—these pollution controls to the costs of cleaner alternatives, notably new and existing natural gas plants and wind power. This comparison allowed us to analyze the potential contribution that pollution control costs may have on retirement decisions and to estimate a range of ripe-for-retirement generating units in the remaining operational fleet.

Alternative scenarios. Last, we examined the effect of several variables that could influence the economic competitiveness of the remaining operational coal fleet, including fluctuations in natural gas prices, a price on carbon dioxide emissions, and the availability of federal tax credits for wind power.

A similar modeling approach was employed by Synapse Energy Economics in a recent analysis of the economic merit of coal-fired power plants in the western United States (Fisher and Biewald 2011).

Examining these four steps of our methodology in detail:

Current Operating Costs

As the first step in our methodology, we calculated the current operating costs of each coal generating unit supplying utility-scale power by adding the cost of the coal itself (including transportation) to fixed and variable operations and maintenance (O&M) costs, measured in dollars per megawatt-hour of power production. Fixed O&M costs typically include ongoing costs that are not affected by the electricity output of the generator, such as staff salaries and routine maintenance. Variable O&M costs, by contrast, are influenced by the generator's electricity output, and include fuel and other materials consumed, equipment and labor costs associated with unforeseen repairs, and other non-routine maintenance needs.

If it would be more expensive to retrofit and continue operating a coal generator than to switch to a cleaner energy source, we consider that generator ripe for retirement.

Characteristics of coal generators that affect operating costs include:

Age. Coal generating units have traditionally been built with an assumed design and economic life span of about 30 years, with the implicit assumption that the generators would be replaced after that period. As they age, generators face substantial reliability, efficiency, and performance problems, which in turn increase operating costs. Older generators also require significantly more maintenance unless they undergo costly, life-extending overhauls (U.S. v. Ohio Edison Co. 2003).

Size. Across the United States, the size of coal generators varies significantly, with power capacities ranging from under 5 MW (typically for industrial purposes) to well over 1,000 MW. Smaller units tend to have higher fixed and variable O&M costs per megawatt-hour of electricity generated. In addition, due to economies of scale in installing some pollution control technologies, it is more difficult for smaller generators to recover the cost of upgrades. Smaller units also tend to be older: the average size of operational coal generators more than 40 years old is less than half that of newer generators.

Capacity factor. The simplest measure of a coal generator's performance is its output, or the number of megawatt-hours supplied to the electric grid. Output is determined both by the size of the generator and by its capacity factor, which is how often and how intensively it is run over time. A generator operating at full power every hour in a year would have a 100 percent capacity factor, although this does not occur in practice because of routine shutdowns for maintenance, variations in electricity demand, unexpected outages, and other reasons. Because coal plants historically have had relatively low operating costs, they are often run at high capacity factors to produce electricity around the clock, often referred to as "baseload" power.

While a typical new, efficient coal power plant has a capacity factor of approximately 85 percent, the average capacity factor for the entire U.S. coal fleet was 64 percent in 2009,[8] and a significant number of coal generators operated at much lower levels. For example, 30 percent of all U.S. coal generators reported capacity factors of less than 40 percent. Many of the underperforming generators are older and require more downtime for maintenance, repairs, and overhauls, or they are not efficient enough to produce power at economically competitive prices during most times of the year.

Many underperforming coal generators are older and not efficient enough to produce power at economically competitive prices during most times of the year.

Heat rate. Fuel efficiency plays a significant role in the operating costs of a coal generator. Heat rate is the measure of how efficiently a generator produces electricity from the fuel it consumes. The lower the heat rate, the more efficient the coal generator is, requiring less fuel to produce a kilowatt-hour of electricity. Older

[8] Due to a large number of smaller generating units that could skew a simple average downward, this result reflects a weighted average based on total generating capacity.

coal generators typically have higher heat rates than newer facilities. A higher heat rate means they have higher fuel and operating costs, and are thus less economic to run, resulting in lower overall capacity factors in today's power markets; it also means they emit more pollution per unit of energy produced.

Older coal generators have higher fuel costs and emit more pollution per unit of energy produced.

Pollution Control Technology and Costs

Burning coal is one of the leading sources of dangerous air pollutants such as SO_2, NO_x, particulate matter, and mercury (EPA 2012; CATF 2010; EPA 2010a; NRC 2010; Lockwood et al. 2009). The EPA is required under the Clean Air Act to develop and enforce standards for these and other pollutants (for more information on the details and status of some recent and upcoming EPA power plant pollution standards, see Appendix B).

These standards do not necessarily require the installation of specific pollution control technologies or that every plant be controlled for every pollutant. Newer coal generators and some upgraded older units are likely to be fitted with equipment that limits harmful emissions to meet specific EPA standards. But until now the owners of many older facilities have been able to avoid making these life-saving upgrades because of grandfathering provisions in the Clean Air Act, which have exempted some existing power plants from strong standards. For example, older plants were not required to be retrofitted with the best available pollution control technologies unless state or local rules required it or the plant was undergoing major modifications. This provision has served as a major loophole allowing existing plants to continue to pollute, and has also created a perverse incentive for power plant owners to extend the lives of these plants far beyond original expectations.

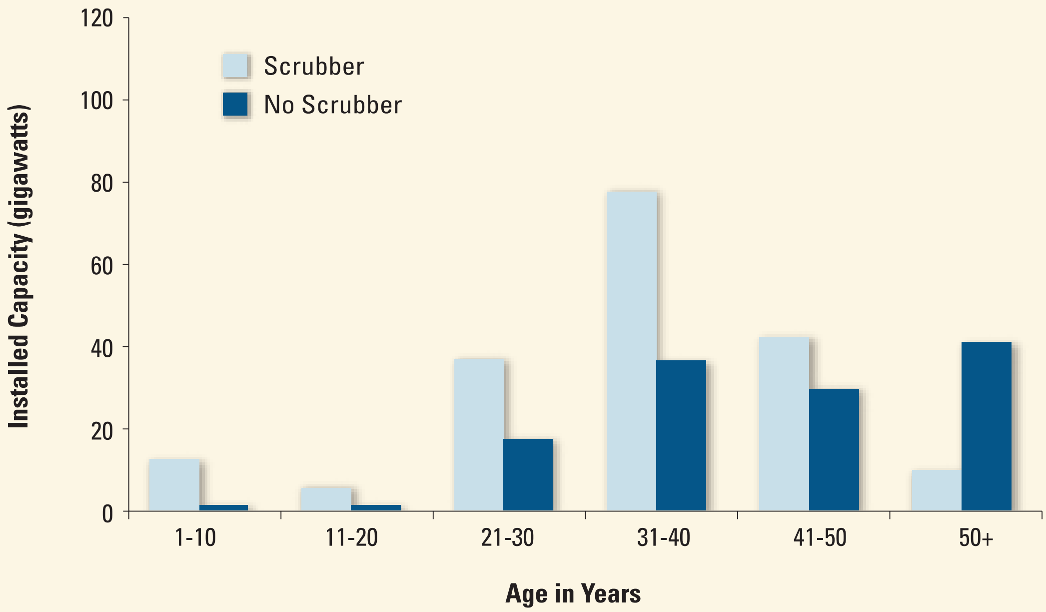
Recently issued EPA standards—such as the mercury and air toxics standard and emissions limits for SO_2 and NO_x—will finally start to reduce the impact of these loopholes. In some cases EPA standards may be met by installing pollution control technologies that are able to reduce the emissions of more than one pollutant. Such co-benefits can cut the emissions of multiple pollutants sufficiently to meet EPA standards, but not necessarily to the lower levels achieved by the most effective individual pollution controls. Further, under existing cap-and-trade programs to curb acid rain and NO_x pollution, plant owners could opt for other means of compliance rather than installing pollution controls, such as switching to cleaner-burning types of coal, operating dirty plants less often, or purchasing pollution allowances (McCarthy and Copeland 2011).

Our analysis does not specifically model the EPA's pollution standards, which will apply to every individual generating unit. Instead, as the second step in our methodology, we evaluate the installation status of pollution controls for four specific pollutants—SO_2, NO_x, particulate matter, and mercury—at each coal generator. For units that do not already have controls for all four pollutants, we calculate the cost to install the control technologies the generator lacks as a means of modernizing the coal fleet. Cost and performance assumptions for all pollution control technologies are based on data from the EPA (EPA 2010b).

Burning coal is one of the leading sources of dangerous air pollutants such as sulfur dioxide, nitrogen oxides, soot, and mercury.

Sulfur dioxide. Burning coal to generate electricity is the largest source of SO_2 pollution in the United States, emitting about 5.7 million tons in 2009. SO_2 takes a major toll on public health, including by contributing (along with other coal plant pollutants such as nitrogen oxides) to the formation of small acidic particulates that can penetrate into human lungs and be absorbed by the bloodstream. This category of particulate pollution—known as $PM_{2.5}$—is linked to the premature deaths of thousands annually through heart and lung disease, as well as to thousands more

Figure 2. Older Coal Generators Are Less Likely to Have SO_2 Controls*



Older coal generators are typically the ones that lack wet or dry scrubbers for controlling SO_2 pollution. According to the EPA, more than 40 percent of U.S. coal generating capacity between 41 and 50 years old, and more than 80 percent of the capacity older than 50 years, lacks this important pollution control technology.

* Results include wet and dry scrubbers installed or planned to be installed through 2013.

Source: EPA NEEDS 2012.

non-fatal heart attacks and hospital admissions (EPA 2010a; NRC 2010). SO_2 emissions also cause acid rain, which damages crops, forests, and soils, and acidifies lakes and streams.

One of the most effective ways to reduce SO_2 emissions is to install a scrubber on the power plant's smokestack. However, nearly half of the coal generating capacity in the United States lacks this long-available equipment for controlling SO_2 pollution. Instead, many plant owners have been able to comply with EPA standards by switching to using lower-sulfur coal, primarily from the Powder River Basin in Wyoming. The oldest generators are typically the most deficient. According to the EPA, more than 40 percent of the U.S. coal generating capacity between 41 and 50 years old, and more than 80 percent of the capacity older than 50 years, lacks SO_2 scrubbers (Figure 2).

For coal generators without a scrubber, our analysis adds the cost of installing wet flue gas desulfurization (FGD) technology, also referred to as a wet scrubber. Wet scrubbers use limestone or other liquid sorbents (a material used to absorb gases) to create a chemical reaction with SO_2 in the flue gas (the combustion exhaust gas in the smokestack). This method absorbs the sulfur from the exhaust gas rising through the smokestack to create a wet slurry waste containing sulfur and other pollutants that requires treatment and proper disposal. This process can achieve a reduction in SO_2 emissions of 95 to 99 percent (Eggers et al. 2010).[9]

[9] Older scrubbers typically using a dry sorbent injection process can achieve capture rates of up to 80 percent, and may require upgrades. However, we have not attempted to capture the costs of upgrading existing scrubbers in this analysis.

Nitrogen oxides. After vehicles, coal power plants are the leading NO_x polluters in the United States, releasing nearly 2 million tons annually. NO_x pollution causes ground level ozone, or smog, which can burn lung tissue and can exacerbate asthma or make people more susceptible to asthma, bronchitis, and other chronic respiratory diseases (Freese et al. 2011; CATF 2010). Like SO_2, NO_x also contributes to acid rain and the formation of particulate matter.

More than half of U.S. coal generators lack post-combustion NO_x pollution controls (EPA 2010b). For these coal generators, our analysis adds the costs of controlling NO_x pollution with a proven and reliable technology called selective catalytic reduction (SCR). Within the smokestack, SCR uses a chemical catalyst to convert NO_x to nitrogen and water, and can cut NO_x pollution by 90 percent or more (Eggers et al. 2010).

Particulate matter. In addition to causing particulate formation through their SO_2 and NO_x emissions, coal plants directly emit particulates from their smokestacks in the form of fly ash. Alarmingly, nearly 80 percent of U.S. coal generators either have no controls for particulate matter, or use outdated methods that do not meet modern standards (EPA 2010b). Our analysis incorporates the costs of installing baghouses inside the smokestack. Baghouses use tightly woven fabrics to capture as much as 99 percent of the particulates released in the flue gas. When baghouses are combined with SO_2 and NO_x pollution control equipment, pollution from both direct and indirect particulate matter is greatly reduced.

More than 80 percent of coal generating capacity older than 50 years lacks SO_2 scrubbers.

Mercury. Coal plants are responsible for more than half of the U.S. human-caused emissions of mercury, a heavy metal that is toxic even in extremely small quantities (EPA 2012). Once emitted to the atmosphere, mercury falls back into the environment and accumulates in water bodies where it is chemically converted into methyl mercury, which builds up through the food chain. Human exposure to methyl mercury comes primarily from eating contaminated fish. Children and pregnant women are particularly susceptible to the neurological impacts of mercury exposure, which can cause brain damage or heart problems (Trasande, Landrigan, and Schechter 2005). Yet until very recently, there have been no federal standards requiring coal plants to limit mercury emissions.

Nearly 80 percent of U.S. coal generators either have no controls for particulate matter, or use outdated methods that do not meet modern standards.

While the equipment for controlling SO_2 and NO_x also removes some mercury from coal generators, the most effective technology for reducing mercury emissions is through activated carbon injection (ACI). Mercury attaches to activated carbon powder that is injected into the flue gas and the particles are then collected by a baghouse or an electrostatic precipitator (ESP). ESP technology was first used in the 1920s, and is an older, less effective way to control particulate matter from coal generators. When ESP is combined with ACI, mercury emissions can be reduced by up to 70 percent. However, when ACI and a baghouse are used, up to 90 percent of mercury emissions can be removed (Eggers et al. 2010). As a result, we assume that a baghouse and ACI equipment are necessary to modernize the coal fleet and sufficiently protect public health and the environment from mercury and particulate matter emissions. Our analysis adds the cost of installing ACI technology, which is currently found on just 8 percent of U.S. coal generators (EPA 2010b).

Water use and coal ash. Addressing SO_2, NO_x, particulates, and mercury emissions are not the only pollution control hurdles owners may face as they consider the costs of extending the lifetimes of older coal plants.

For example, a typical coal plant using "once-through" cooling withdraws hundreds of millions of gallons of water daily from adjacent lakes and rivers to cool its steam for re-use. While most of the water is returned to the water body, the withdrawals kill fish and their eggs and larvae, and the hot water returned to the lake or stream can harm aquatic ecosystems (Gentner 2010). Cooling towers, which release heat to the atmosphere so the same water can be recycled to cool the plant again, increase water consumption through evaporation. However, they reduce power plant *withdrawals* from lakes and rivers by more than 90 percent compared with once-through systems. Nationwide, about 40 percent of the coal generating capacity still uses once-through cooling.

> *Activated carbon injection technology to control mercury pollution is found on just 8 percent of U.S. coal generators.*

Coal plants also create vast quantities of ash, a solid waste that contains arsenic, selenium, cadmium, lead, mercury, and other poisons, which can leak into ground or surface water when disposed. Plant owners can significantly reduce the risks of contamination by upgrading the facility's ash-handling systems, which may include converting from wet to dry ash handling, employing lined landfills, and installing new wastewater treatment equipment.

Ideally, an analysis of whether a coal generator is ripe for retirement would consider the costs of lower-impact cooling systems and ash handling, which are both subject to new rules from the EPA in 2012 (see Appendix B). However, because of a lack of consistent data at the generator level, we did not include these costs in our analysis.

Comparing Coal against Cleaner Energy Sources

For those individual coal generators lacking SO_2 scrubbers, post-combustion NO_X controls, particulate baghouses, or ACI for mercury, the third step of our analysis adds the capital and operating cost of each respective control technology to that unit's operating costs. (Such costs are already embedded in the operating costs of the rest of the generators in the nation's coal fleet, which already have such pollution control equipment.)

Our analysis then compares the estimated total cost to operate each coal generator—including those generators with existing pollution controls—at its 2009 capacity factor against the cost of producing power from several competitive energy resources: existing natural gas combined-cycle (NGCC) plants, new NGCC plants, and new wind power facilities.[10] We did not consider new nuclear or coal with carbon capture and storage (CCS) plants as near-term alternatives because of their long construction lead times, high costs, and limited number of proposed projects. We also did not consider new solar, biomass, or geothermal projects, which are currently more expensive than wind power, but could make modest near-term contributions in some parts of the country.

The capital, operating, and fuel (including transportation) costs for new and existing NGCC plants are based primarily on assumptions from the *Annual Energy Outlook* published by the EIA (EIA 2012c; EIA 2011a). The costs and capacity factors for building and operating new wind projects, which is currently the most cost-competitive renewable energy technology on average nationwide, are based on data from a large sample of actual U.S. wind projects collected by Lawrence Berkeley National Laboratory (Wiser and Bolinger 2011).

If a coal generator's total cost of power production is higher than at least one of these competing energy alternatives, we deem that generator ripe for retirement. In Chapter 3, we establish a range of results for our core scenario that compares the operating costs of coal generators with the operating costs of average new and existing NGCC plants. The lower bound of that range is defined by comparing the costs of each coal generator to new NGCC plants, which are more expensive to operate because they are still amortizing their capital and financing costs. The upper bound of that range is defined by comparing the costs of each coal generator to existing NGCC plants, which are less expensive to operate because their capital and financing costs have been largely recovered.

[10] Our analysis compares the costs of individual coal generators with the typical national average cost of alternatives. It does not consider regional cost and performance differences. This is a static analysis comparing a snapshot of these costs as they currently exist, and does not consider potential cost reductions or increases for different technologies over time. In reality, retiring uneconomic plants and replacing them with cleaner alternatives will happen over a period of several years.

Alternative Scenarios

As the last step in our analysis, we present several alternative scenarios to examine the effect of key external variables that could each influence the relative economic competitiveness of the operational coal fleet.

Natural gas prices. Fluctuations in the price of natural gas have a substantial impact on the entire electric power industry. While natural gas prices are currently low, a significant increase in natural gas demand for electricity, heating, and other uses could put upward pressure on those prices. The United States experienced such a price increase between 2004 and 2008 after a significant increase in natural gas power plant construction. For our core analysis, we assume a national 20-year levelized natural gas price of $4.88 per million British thermal units (MMBtu) for both existing and new NGCC units, based on the EIA's reference case projections for the electricity sector in its *Annual Energy Outlook 2012* (EIA 2012c). However, to account for uncertainty in fuel supply and demand, we also examined the effect on the economics of coal generators using a low and high natural gas price forecast for both new and existing natural gas facilities. Our low natural gas price case assumes a 25 percent decrease in the EIA's reference case projections to $3.66/MMBtu, while the high price case represents a 25 percent increase in the EIA projections to $6.10/MMBtu.

Wind production tax credit (PTC). The federal PTC currently provides a 2.2-cent-per-kilowatt-hour benefit for the first 10 years of a wind power facility's operation.[11] This policy, which has contributed to the significant growth of domestic wind power, is set to expire at the end of 2012. Our analysis compares the economics of coal generators with the cost of a new wind facility at an average wind resource location (with a 35 percent capacity factor) both with and without the PTC. The PTC scenario assumes that the tax credit will be renewed.

Reducing carbon dioxide emissions. Nationally, coal plants are one of the largest sources of the carbon dioxide emissions driving global warming. While Congress has yet to adopt a national policy to reduce carbon dioxide emissions, the EPA is moving forward with its legal responsibility under the federal Clean Air Act to set standards that limit carbon dioxide emissions from power plants. While the timing and ultimate structure of any such standards or any future climate legislation remain uncertain, we analyze the effect of putting a price on carbon as a generic proxy for a constraint on carbon dioxide emissions. We assume a carbon price of $15 per ton, which is consistent with more conservative price forecasts from several government, industry, and expert analyses (Johnston et al. 2011).

288 coal generators in 34 states have announced plans to retire or convert to natural gas, totaling 41.2 GW of capacity (about 12 percent of U.S. coal generating capacity).

Analysis of Announced Coal Generator Retirements

From 2009 through May 2012, 288 coal generators (41.2 GW) have announced plans either to retire or to convert to natural gas (Figure 3, p. 28) (SNL Financial 2012). Retirements have been announced in 34 states, with the vast majority in the eastern half of the country. Some of the units have already shut down, while the rest are scheduled to be retired over the next several years. Other retirements may be added to the growing list in the coming months, as the pace of announcements has quickened since the beginning of 2011.

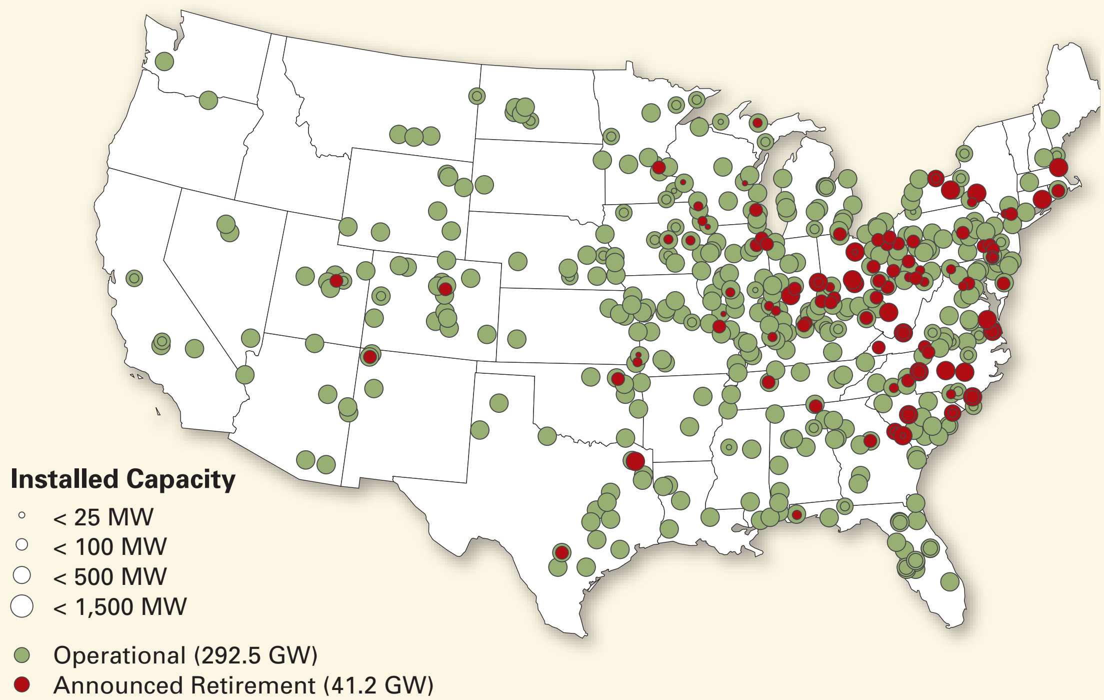
In 2009, retiring generators accounted for 7.7 percent of the electricity generated from coal and 3.8 percent of electric generation from all sources combined. These units emitted more than 886,000 tons of SO_2, 219,000 tons of NO_X emissions, and 150 million tons of CO_2 in 2009 alone, as well as significant amounts of mercury, particulates, and other toxic pollution.[12]

As we evaluate the retirement potential for the remaining operational coal fleet, there are several important common characteristics among the

[11] We assume the PTC has a 20-year levelized value of two cents per kilowatt-hour (Wiser and Bolinger 2011). This represents the present value of the PTC to a wind power project over its typical expected lifetime.

[12] Generation and emissions data are for 2009, the latest year for which reasonably comprehensive information was available. Some of the retiring generating units did not report generation and/or emissions, and were excluded from these summary results.

Figure 3. Location of 41.2 GW of Announced Retirements vs. Remaining Operational Fleet*



From 2009 through May 2012, 288 coal generators in 34 states have announced plans to retire or convert to natural gas, totaling 41.2 GW of capacity or about 12 percent of total U.S. coal generating capacity.

* Includes all utility-scale generating units using coal as a primary fuel source.

Source: Based on data from SNL Financial 2012.

announced retirements that help inform the premise and methodology of our analysis. For example, the announced retirements are some of the oldest, least utilized, and dirtiest coal generators in the United States.

Oldest: Eighty-seven percent of already retiring generators began operating before 1970. Their average age is 50 years, compared with 38 years for the U.S. coal fleet as a whole (Figure 4).[13]

Least utilized: In 2009, the average capacity factor of the retiring generators was 44 percent compared with 64 percent for the total U.S. coal fleet. Forty-three percent of the retirees reported capacity factors under 30 percent (Figure 4).

Dirtiest: Eighty-eight percent of retiring generators lack at least three of the four air pollutant control technologies evaluated in our analysis, while 56 percent lack all four.

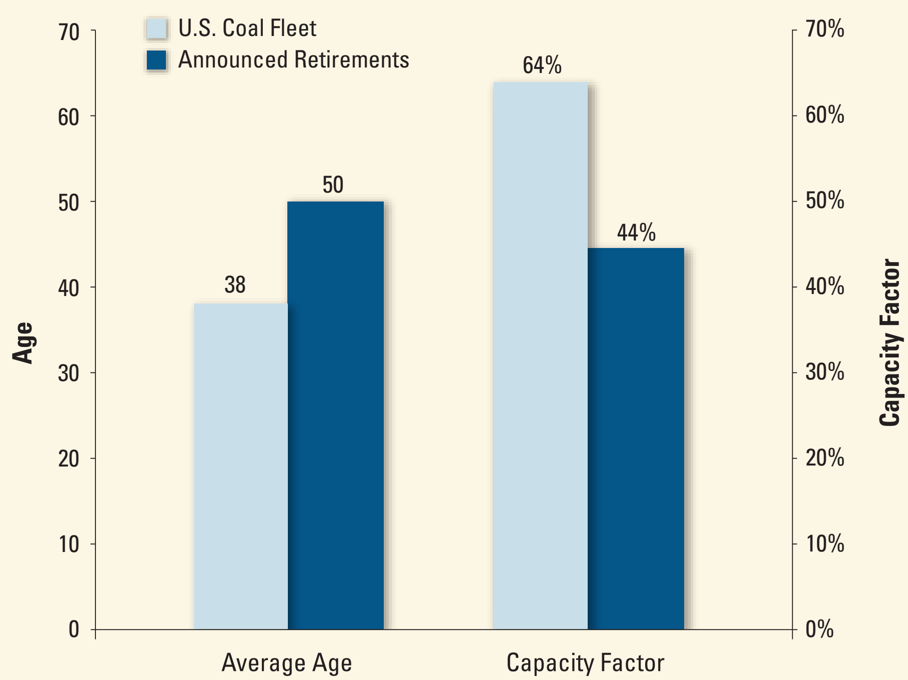
In addition, most of the retiring units no longer make the cut from an economic standpoint. To illustrate this point, we employed the same economic analysis for the list of coal generators that have already been slated for retirement as we used for the

[13] Results for age and capacity factor reflect a weighted average based on total generating capacity.

operational fleet.[14] We found that more than 30 percent of the retiring generators are not currently economically competitive with the average existing NGCC facility. The economics tilt further in favor of existing natural gas when factoring in the cost of upgrading the coal generators with modern pollution control technologies.

Figure 5, p. 30, shows the estimated operating costs of the retiring coal generators (black dots) if, instead of retiring, they were to add pollution controls and keep running, compared with the cost of operating an existing NGCC facility (red line). As the figure indicates, the vast majority of retiring coal generators (86 percent) falls above the red line, meaning they would be more expensive to operate than an existing NGCC facility. Furthermore, when compared with alternative scenarios, such as a low natural gas price case or wind power including tax credits, virtually all of the retiring coal generators are not economically competitive. Economic considerations like this help explain the decision that owners have made to retire the 288 coal generators rather than retrofit them.

Figure 4. Announced Retirements Are Older and Less Utilized than the Remaining Operational Fleet*

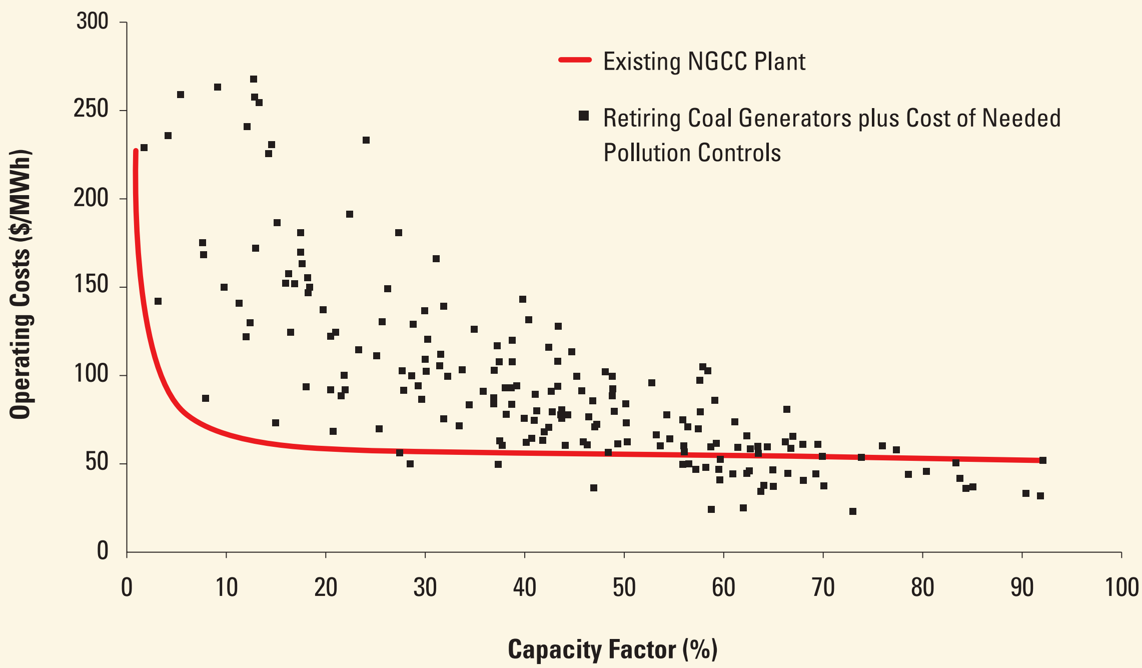


Compared with the total fleet of U.S. coal generators, the coal generating units that are scheduled to be retired are, on average, older and operated less frequently.

* Results reflect a weighted average based on total generating capacity.

[14] Sufficient data were available to conduct the economic analysis on 243 of the 288 coal generating units that have announced plans to retire. The remaining coal generators were removed from the analysis.

Figure 5. Operating Costs of 86 Percent of Announced Coal Generator Retirements Are Significantly Higher than Operating Costs of Existing Natural Gas Plants



Each black dot on the graph represents the operating costs of a coal generator in dollars per megawatt-hour—including the annualized cost of adding pollution control equipment when lacking—as a function of the generating unit's capacity factor. The red line reflects the cost of operating an average existing NGCC facility, with costs declining as the capacity factor increases. The operating costs of 86 percent of the retiring coal generators already announced cannot compete with the operating costs of existing natural gas generation plants.

CHAPTER 3
Ripe for Retirement Results

Like the 288 coal-fired electricity generators (or units) that are already calling it quits, there are still many more in the remaining fleet that are similarly old, dirty, unproductive, and increasingly uneconomic. Given the long overdue need to invest in modern pollution control technology for coal generators, plus stiff competition from cleaner, lower-cost resources such as wind power and natural gas, and technology to reduce demand through increased efficiency, the economics of keeping old coal generators operating has become harder and harder to justify. The trend is clear: if we want to continue a transition toward a cleaner, healthier, more sustainable energy system, it is critical to plan appropriately for the next wave of coal generator retirements while maintaining reliable and affordable electricity. The results of our economic analysis, which identify additional coal generators that are likely candidates for retirement, serve as a first step in that process.

National Findings

Nationwide, we identified between 153 and 353 additional coal generating units meeting our ripe-for-retirement threshold. Collectively, they represent 16.4 to 59.0 GW of coal generating capacity, equal to between 4.9 percent and 17.7 percent of total coal power capacity. Given their weak competitive position, investment in those coal generators should be subject to rigorous review, as regulators, utilities, banks and others evaluate whether they should be upgraded or shut down over the next several years. These additional generators, combined with the 41.2 GW of coal retirements already announced, represent between 17.3 and 30.0 percent of total U.S. coal-fired generating capacity. Although coal generators are scattered throughout the United States, most of those ripe for retirement are concentrated in the eastern half of the country, where most of the coal fleet is located (Figures 6 and 7, p. 32). This area has been dependent on coal for many decades, with many plants built a half-century ago, so it is not surprising that the eastern United States also hosts the largest concentration of plants that are ripe for retirement. In general, coal plants in the western United States tend to be younger and more likely to have pollution controls installed.

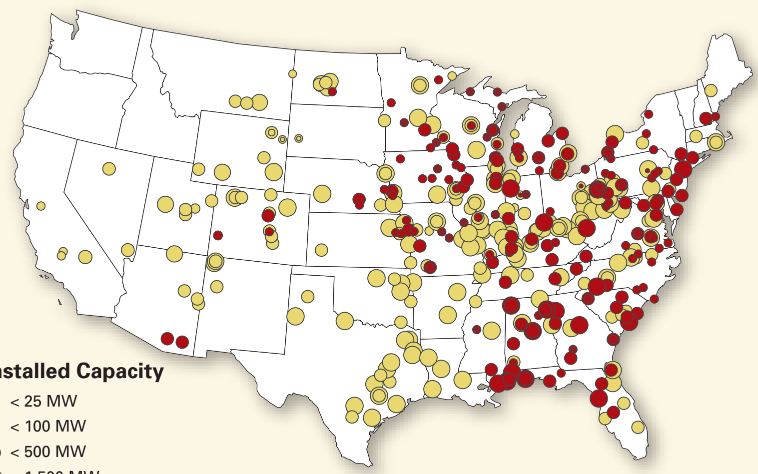
Nationwide, we identified between 153 and 353 coal generating units that meet our ripe-for-retirement threshold.

As described in the previous chapter, to determine low and high estimates of the number of coal generators ripe for retirement in the remaining operational fleet, we compared the costs of each coal generator (including costs for any missing pollution controls) with the costs of cleaner alternatives.

It is important to note that although for our core analysis we determined the low and high estimates by comparing a coal generator's operating costs with the operating costs of natural gas facilities, either new or existing (respectively), our analysis is not intended to suggest that natural gas would replace all coal generators deemed ripe for retirement. Initially, many of the coal generators could simply be retired and not replaced at all because of the large amount of excess capacity currently in the system, especially at recently built NGCC plants that are still operating at well below capacity (see Chapter 4). But over time, as electricity demand increases and more coal generators are retired, we expect the retiring capacity could be replaced through a combination of existing and new natural gas facilities, new renewable energy resources, plus reduced demand through investments in energy efficiency. For example, our analysis found a similar amount of ripe-for-retirement coal generating capacity when compared with new wind development or natural gas (see Findings from Alternative Scenarios section). This indicates that in many areas of the country, wind power offers a viable and affordable alternative to coal and natural gas generation.

Figure 8 illustrates the result of the economic analysis for our low and high estimates. Each black dot on the graph represents the operating costs of a coal generator in dollars per megawatt-hour—including the annualized cost of adding appropriate

Figure 6. 59 GW of Ripe-for-Retirement Coal Generators Located in 31 States (High Estimate vs. Remaining Operational Coal Fleet)



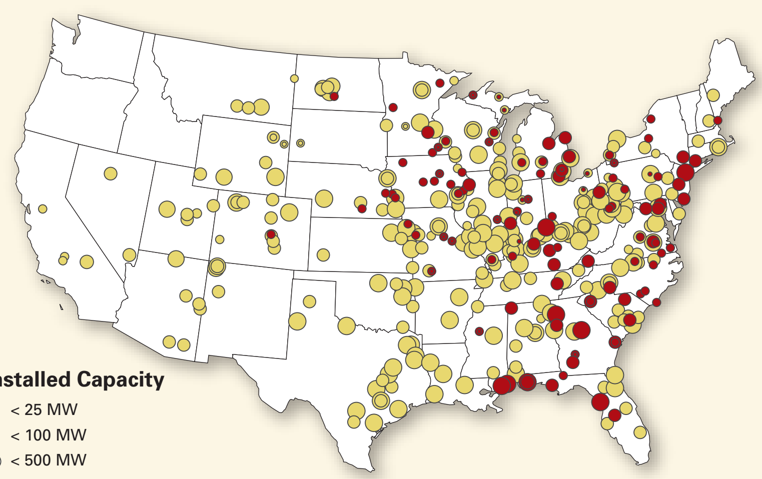
Installed Capacity

- < 25 MW
- < 100 MW
- < 500 MW
- < 1,500 MW

- Operational (233.2 GW)
- Ripe for Retirement (59.0 GW)

Under our high estimate, which compares the operating costs of coal generators that have pollution controls with the operating costs of *existing* NGCC plants, 353 coal generators in 31 states are uneconomic and thus ripe for retirement, totaling 59 GW of capacity.

Figure 7. 16.4 GW of Ripe-for-Retirement Coal Generators Located in 28 States* (Low Estimate vs. Remaining Operational Coal Fleet)



Installed Capacity

- < 25 MW
- < 100 MW
- < 500 MW
- < 1,500 MW

- Operational (266.0 GW)
- Ripe for Retirement (16.4 GW)

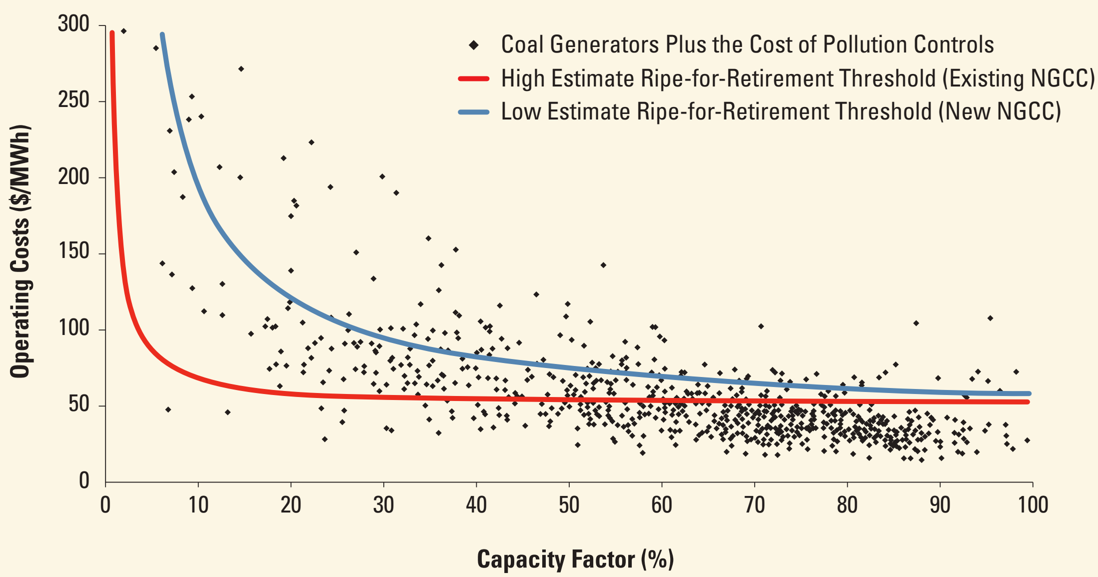
Under our low estimate, which compares the operating costs of coal generators that have pollution controls with the operating costs of *new* NGCC power plants, 153 coal generators in 28 states are uneconomic and thus ripe for retirement, totaling 16.4 GW of capacity.

* Includes all utility-scale generating units using coal as a primary fuel source, except those that have already been announced for retirement.

pollution control equipment—as a function of the generating unit's capacity factor. After excluding coal generators with missing data and those from outside the power sector (e.g., industrial units), we evaluated 862 coal generators with a combined power capacity of 292 GW. According to data from the EIA, the cost of operating an existing NGCC unit—shown as the red line—declines from $54.00/MWh at a 40 percent capacity factor (which is about the average capacity factor they operate at today) down to $51.60/MWh at a capacity factor of 85 percent (EIA 2012c; EIA 2011a). Operating costs decline as capacity factor increases because fixed costs are spread across more megawatt-hours of electricity production. The cost of building and operating a new NGCC unit—shown as the blue line—similarly declines from $80.40/MWh at a 40 percent capacity factor to $60.20/MWh at an 85 percent capacity factor.

Under our low estimate, 153 ripe-for-retirement coal generating units (accounting for 16.4 GW of coal-fired generating capacity) are above the blue line, indicating they are more expensive to operate than a new NGCC plant. Under our high estimate, an additional 200 coal generators are uneconomic (i.e., above the red line) compared with an existing NGCC unit, totaling 353 units (or 59 GW) identified as ripe for retirement. Most of the coal generators that are less expensive to operate than an average existing gas plant (i.e., below the red line) have capacity factors greater than 50 percent. These units operate more often in part

Figure 8. Operating Costs* of Ripe-for-Retirement Coal Generators vs. Operating Costs of Existing and New Natural Gas Plants



The scatter plot shows the operating costs of coal generators we deem ripe for retirement under our low and high estimates. Each black dot represents the operating costs of a coal generator in dollars per megawatt-hour, including the cost of pollution control equipment, as a function of its capacity factor. The blue line reflects the operating costs of a *new* NGCC facility; the 153 coal generators that are above the blue line are ripe for retirement under our low estimate. The red line represents the operating costs of an *existing* NGCC facility; the 353 coal generators above the red line are ripe for retirement under our high estimate. Many of the coal generators identified as ripe for retirement are underperformers that produce electricity at capacity factors well below the 2009 nationwide average of 64 percent.

* The operating cost of each coal generator includes the annualized cost of adding needed pollution control equipment.

because they are more economically competitive: they are typically larger, more modern and efficient generators currently capable of producing power at lower cost.

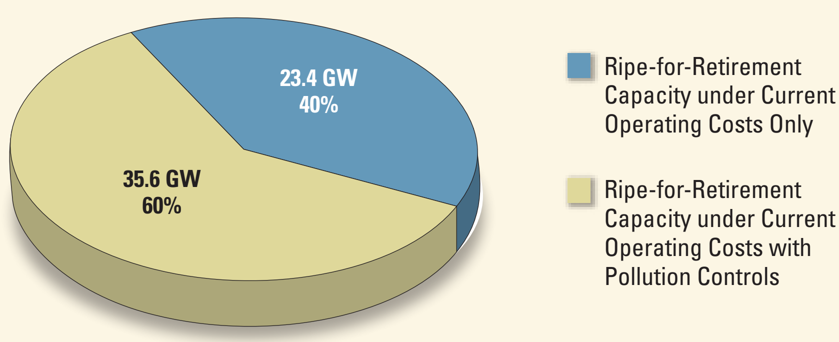
No single factor causes a coal generating unit to become ripe for retirement. In many cases, the combination of old age, inefficiency, and strong competition from alternative energy sources is enough to trigger the designation. For example, 40 percent of the 353 generators (representing a capacity of 23.4 GW) identified as ripe for retirement under our high estimate are not economically competitive even *without* adding the cost of installing modern pollution control equipment (Figure 9). For the additional 35.6 GW of coal generators that meet the ripe-for-retirement threshold, the cost of modernizing with vital pollution control equipment is an important factor but not the only one in determining their inability to compete economically. Age, performance, and the nearby presence of cheaper and cleaner energy alternatives are also substantial drivers of decisions to retire a coal generator.

Forty percent of ripe-for-retirement coal generators (23.4 GW) are not economically competitive even without the added cost of installing modern pollution controls.

Inefficient and Underperforming

Table 1 summarizes characteristics of the coal generators that we calculate as ripe for retirement, compared with the list of already announced retirements.[15] It is important to note that while the retirements in our high estimate represented 17.7 percent of the nation's total coal fleet and 12.9 percent of coal-fired power generation in 2009, these generators produced just 6.3 percent of U.S. electricity consumption from all sources. Combining the 288 generators already slated for retirement with the 353 generators we identify from our high estimate, represents a capacity of 100.2 GW, which accounts for 30 percent of coal

Figure 9. 40 Percent of Ripe-for-Retirement Coal Generators (Under the 59 GW High Estimate) Are Already Uneconomic Even Without Including Pollution Control Costs



Primarily because of age, inefficiency, and the nearby presence of cheaper and cleaner energy alternatives, 40 percent of the coal generating capacity (23.4 GW) deemed ripe for retirement under our high estimate is not currently economically competitive, even without the added cost of installing modern pollution control equipment. For the remaining ripe-for-retirement coal capacity, the cost of modernizing with vital pollution control equipment is an important factor but not the only one in determining its inability to compete economically.

[15] A full listing of generators deemed ripe for retirement can be found in Appendix E.

Table 1. Ripe-for-Retirement Coal Generators Compared with Already Announced Retirements

	Announced Retirements	Ripe-for-Retirement Generators	
		High Estimate	Low Estimate
Number of coal generators	288	353	153
Total capacity[a] (gigawatts)	41.2	59	16.4
Percent of total U.S. electricity consumption	3.8%	6.3%	1.7%
Average generator age (years)[b]	50	45	45
Average generator capacity factor[c]	44%	47%	47%
Average generator size (megawatts)	143	167	107
Percent of generators lacking three or more pollution control technologies[d]	88%	71%	83%
Avoided annual CO_2 emissions if all identified generators are retired (million tons)[e]	88 – 150	157 – 260	52 – 75

[a] Capacity is the amount of electricity a coal generator (or group of generators) can produce operating at full (100%) power. One gigawatt is equal to 1,000 megawatts.

[b] Age is as of 2012. Results reflect a weighted average based on total generating capacity.

[c] Capacity factor is as of 2009 (the most recent year of available complete data), which measures how often and intensively a generator is run over time, calculated as the ratio of actual power output to potential output if the generator had operated at full (100%) capacity over the same period. Results reflect weighted averages based on total generating capacity.

[d] Pollution control technologies evaluated include scrubbers (for sulfur dioxide), selective catalytic reduction (for nitrogen oxides), baghouses (for particulate matter), and activated carbon injection (for mercury).

[e] The low end of the avoided annual CO_2 emissions range reflects replacement of coal with natural gas (existing NGCC units for the high estimate and announced retirements, new NGCC units for the low estimate); the high end of the avoided annual CO_2 emissions range reflects replacement of coal with zero-carbon-emitting resources such as wind, or reduced energy demand due to increased energy efficiency.

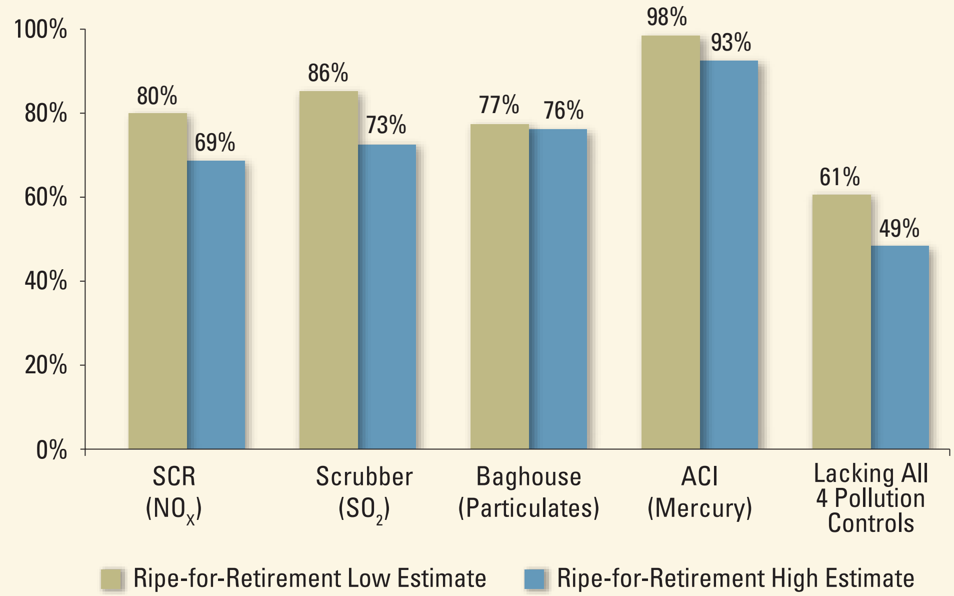
fleet capacity; that capacity, however, is equivalent to only 10 percent of total U.S. power consumption. In other words, the coal generators already shutting down and those on the ripe-for-retirement lists are not the workhorses of the electric power industry. They are largely underperformers that produce electricity at capacity factors well below the nationwide average of 64 percent for coal. Nearly a third of the generators in our high estimate of ripe-for-retirement generators reported capacity factors below 30 percent in 2009.

Old Age, Small Size, and a Lack of Pollution Controls

Like the fleet of announced retirements, the coal generators identified as ripe for retirement are among the oldest, smallest, and dirtiest in the country. The average first year that generators in our high estimate first began operating is 1967. Eighty-six percent of the 353 coal generating units in the high estimate have exceeded their 30-year expected lifetime. Furthermore, the average size of the generators in the high estimate is 167 MW, well below the typical 500 MW size of a modern coal generator.

In the high estimate, 73 percent of the generators lack a wet or dry scrubber to control SO_2 emissions and 93 percent have not installed activated carbon injection to reduce mercury pollution (Figure 10, p. 36). Many of the generators lack controls for more than one pollutant. More than 70 percent of the generators in the high estimate do not have proper controls for at least three of the four pollutants analyzed. Nearly half are missing proper equipment for all four types of pollution.

Figure 10. Most Ripe-for-Retirement Generators Lack Pollution Controls (by Control Type)



The 353 coal generators identified in the high estimate as ripe for retirement are among the dirtiest nationwide. The vast majority lack proper, modern equipment for controlling SO_2, NO_x, particulates, and mercury emissions. Nearly half the generators do not have proper equipment for all four types of pollution analyzed.

SCR = selective catalytic reduction; ACI = activated charcoal injection

Public Health and Environmental Benefits of Retiring Coal

Retiring some of the nation's dirtiest coal capacity would substantially cut many harmful emissions. For example, shutting down all 353 coal generators in the high estimate would annually avoid approximately 1.3 million tons of SO_2 and 300,000 tons of NO_x emissions, as well as significant amounts of mercury, particulates, and other toxic emissions, depending on the emissions profile of the resources that replace it.[16] Less pollution would provide important benefits to public health and the environment (EPA 2012; CATF 2010; EPA 2010a; Gentner 2010; NRC 2010; Trasande, Landrigan, and Schechter 2005), including:

- fewer incidences of asthma aggravation, bronchitis, and chronic respiratory disease, as well as premature deaths from heart and lung disease and stroke;
- greater protection of children's brain development;
- less damage to crops, forests, lakes, and streams;
- less danger to water supplies from toxic ash and sludge; and
- fewer fish kills and strains on water bodies from a reduction in water withdrawals and consumption for cooling power plants.

Shutting down the 353 coal generating units would also reduce CO_2 emissions, the primary contributor to global warming. Coal plants are the nation's top source of CO_2 emissions, emitting more than all cars, trucks, buses, and trains combined (EIA 2011c). Replacing 59 GW of coal generators with increased generation from existing natural gas facilities would reduce annual CO_2 emissions from power generation by approximately 157 million tons. If supplanted entirely with wind power, other zero-emissions sources, and reduced demand due to greater energy efficiency, CO_2 emissions from power

[16] Emissions reductions based on 2009 data as reported to the EIA. Forty of the 353 generating units listed in the high estimate, representing about 600 MW of capacity, did not report SO_2 and/or NO_x emissions, and were not included in the results.

generation would be cut by 260 million tons annually—equal to a 10.4 percent reduction in 2010 U.S. power sector emissions. Moreover, if the 59 GW of ripe-for-retirement coal generating capacity is added to the 41.2 GW of announced retirements, avoided CO_2 emissions would be between 245 million tons and 410 million tons, a reduction of between 9.8 percent and 16.4 percent. While this would mark an important step forward in addressing climate change, much deeper reductions will be needed in the power sector and across the economy. In order to get to emissions levels that are 80 percent below 2005 levels by 2050—cuts in global warming emissions that leading scientists say are necessary to avoid the most dangerous effects of global warming—many experts believe that the electric power sector will need to be fully decarbonized much sooner (Luers et al. 2007) (see box).

America's Most Ripe-for-Retirement Power Providers

The coal generators we identify as being ripe for retirement are owned by dozens of different utility companies and other power producers. However, in our analysis, several companies emerge as having considerably more coal generators that are ripe for retirement than others. For example, Southern Company, one of the nation's largest electricity producers—with operations in Alabama, Georgia, Mississippi, and the panhandle of Florida—ranks as the power provider with the most coal generators and the most total gigawatts of power generation capacity that are ripe for retirement (Table 2, p. 38). Southern Company owns more than 15.6 GW, or about 27 percent, of the 353 coal generating units deemed ripe for retirement under our high estimate. This is nearly triple the number of coal units owned by the second-ranked power provider: the Tennessee Valley Authority (TVA). TVA, a federally owned corporation that largely produces wholesale power, provides electricity to approximately 9 million customers in southeastern states. Both Southern Company and TVA also share the distinction of being the two power providers most dependent on coal imports from other states, according to a recent Union of Concerned Scientists analysis (Deyette and Freese 2010). In 2008, Southern Company and TVA spent

Ripe-for-retirement coal generators are among the dirtiest nationwide because more than 70 percent lack at least three of the four modern pollution controls analyzed.

What about Carbon Emissions and the Rest of the Coal-fired Generation Fleet?

Apart from the significant amount of coal-fired generation that is already ripe for retirement based on current economic considerations, the nation should consider the long-term implications of continuing to operate the remaining 233 GW of coal-fired generation capacity. The stark reality is that the vexing problem of climate change will require more profound and aggressive action to rapidly decarbonize the power sector to reduce the impact of this major source of global warming emissions (e.g., Specker 2010; Cleetus et al. 2009). With the health and economic risks of unchecked climate change becoming more and more apparent, policy makers should take broad action to cut emissions, including putting a price on carbon pollution. With this future cost in mind, making costly investments to upgrade the remaining coal fleet is financially risky and may simply be postponing the inevitable: that these plants will also eventually need to be shut down (or retrofitted with very expensive, and as yet untested, carbon dioxide capture and sequestration technology) to achieve emissions reduction targets (Freese et al. 2011). A better use of this large capital expense could be made by investing it in cleaner, low- or no-carbon alternatives (as outlined in Chapter 4).

Table 2. Top 10 Power Companies with Most Ripe-for-Retirement Generators (High Estimate)

Rank	Power Company	Ripe-for-Retirement Generators			Capacity of Announced Retirements (MW)
		Capacity (MW)	Number of Generators	Location (by State)	
1	Southern Co.	15,648	48	Alabama, Florida, Georgia, Mississippi	1,350
2	Tennessee Valley Authority	5,385	28	Alabama, Kentucky, Tennessee	969
3	Duke Energy Corp.	2,760	17	Indiana, North Carolina	3,230
4	American Electric Power Company, Inc.	2,355	4	Indiana, Virginia, West Virginia	5,846
5	FirstEnergy Corp.	2,075	7	Ohio, Pennsylvania	3,721
6	Public Service Enterprise Group Inc.	1,713	4	Connecticut, New Jersey	0
7	Progress Energy, Inc.	1,685	3	Florida, South Carolina	2,532
8	Wisconsin Energy Corp.	1,653	10	Michigan, Wisconsin	384
9	SCANA Corp.	1,405	3	South Carolina	883
10	GenOn Energy, Inc.	1,385	6	Maryland, West Virginia	3,882

nearly $4.2 billion and $2.0 billion respectively to import coal from outside the states they serve. Retiring their coal generators would cut each utility's dependence on coal imports and could help keep more energy dollars within local economies inside the states they serve.

One area where Southern Company and TVA differ from other power companies in the top 10 list is in their relatively modest commitments to begin shutting down some of their oldest and dirtiest coal generators. TVA has announced the retirement of seven coal units, representing close to 1,000 MW of capacity, while Georgia Power is the only one of Southern Company's four subsidiaries to announce the retirement of coal generators—five units adding up to 1,350 MW of capacity or about 5 percent of Southern Company's total coal fleet. By contrast, American Electric Power has announced the retirement of 25 coal generators that add up to more than 5,800 MW. Four other power companies on the list—GenOn Energy, First Energy, Duke Energy, and Progress Energy—have announced more than 2,500 MW of retirements each.

State-level Findings

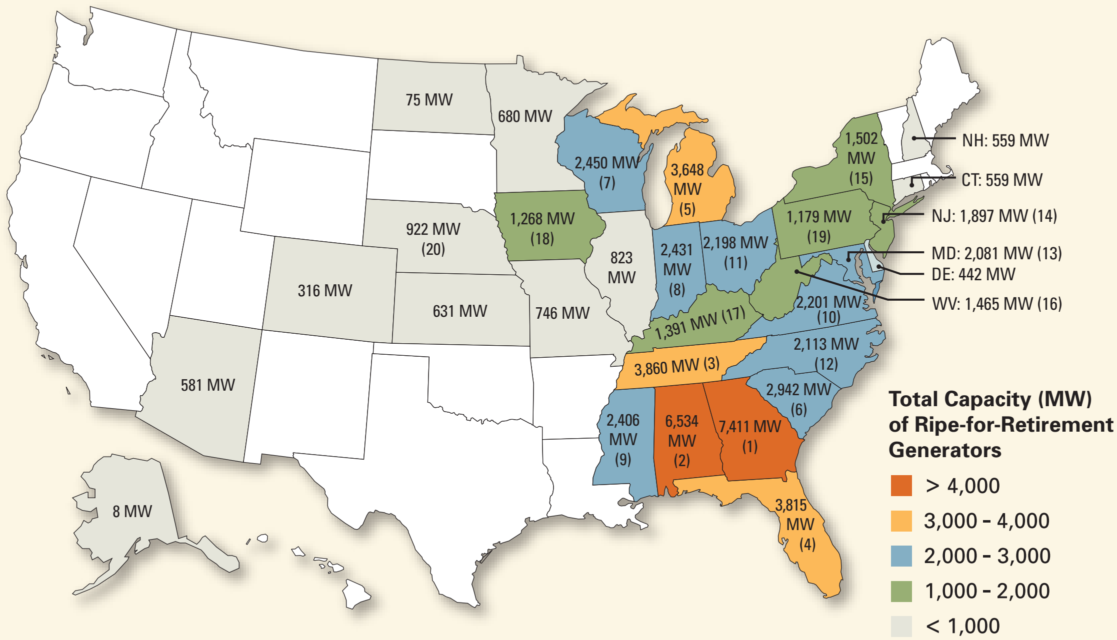
High-Estimate State Results

Under the high estimate, the 353 ripe-for-retirement coal generators are located in 31 states (Figure 11). The greatest concentration of uneconomic coal generators is in the eastern half of the nation, from the Southeast through the Midwest and Mid-Atlantic. Nineteen states—all from these three regions—each have more than 1,000 MW of coal capacity ripe for retirement.

Table 3, p. 40, ranks the top 20 states by total capacity of the 353 coal generators ripe for retirement under the high estimate and summarizes key state results.[17] Georgia tops the list, with more than 7,400 MW of capacity more expensive to run than existing natural gas power plants—12.6 percent of the total across all states. Georgia's coal fleet is one of the dirtiest in the country, with 77 percent of the 22 generators that made the list lacking modern control equipment for at least three of the four pollutants we evaluated. Yet, even without accounting

[17] See Appendix C for a table that ranks and summarizes results for all 31 states containing the 353 coal generators in our high estimate that are ripe for retirement.

Figure 11. Ripe-for-Retirement Generating Capacity Is Concentrated in Eastern States* (High Estimate: 59 GW)



Under the high estimate, 353 coal generators in 31 states were identified as being ripe for retirement. Nineteen states each have more than 1,000 MW of coal capacity ripe for retirement, all from the Southeast, Midwest, and Mid-Atlantic regions. Georgia leads all states with more than 7,400 MW of capacity more expensive to generate by coal than by existing NGCC power plants.

* Rankings for top 20 states listed in parentheses. State totals do not include announced retirements.

for the cost of installing pollution controls, nearly 60 percent of Georgia's capacity (4,406 MW) that is ripe for retirement is uneconomic compared with existing natural gas.

Michigan ranks fifth on the table in terms of total capacity (3,648 MW) ripe for retirement, but has the greatest number of coal generators on the list, with 39 units. Thus, most of these generators are small, averaging 94 MW, with all but one having power capacities of less than 200 MW. Most other states across the Midwest also have a high number of smaller generators that made the ripe-for-retirement list. For example, the average capacities of those generators in Indiana, Iowa, Minnesota, Ohio, and Wisconsin all range between 60 MW and 160 MW. By contrast, uneconomic generators in the Southeast tend to be larger. In Florida, Georgia, and Mississippi, the average capacity of uneconomic generators is 300 MW or greater. This regional difference is due, in part, to the fact that coal plant owners in the Midwest and Mid-Atlantic have already retrofitted some of their largest generators, something that typically has not been done in the Southeast.

> *The greatest concentration of uneconomic coal generators is in the eastern half of the nation, from the Southeast through the Midwest and Mid-Atlantic.*

Not surprisingly, the 31 states on the list are some of the most coal-dependent in the country. Twenty of the states produced more than 50 percent of their total

Table 3. Top 20 States With the Most Ripe-for-Retirement Coal Generation Capacity (High Estimate)

Rank	State	Capacity (MW)	No. of Coal Generators	Average Online Year[a]	Average Capacity Factor	Avoided CO_2 Emissions (million tons)[b]
1	Georgia	7,411	22	1969	58%	20.5 – 36.4
2	Alabama	6,534	24	1963	45%	15.1 – 25.8
3	Tennessee	3,860	22	1955	33%	6.4 – 10.8
4	Florida	3,815	11	1978	50%	10.9 – 18.0
5	Michigan	3,648	39	1961	52%	12.0 – 19.3
6	South Carolina	2,942	11	1970	46%	6.2 – 11.4
7	Wisconsin	2,450	18	1962	47%	7.2 – 11.9
8	Indiana	2,431	16	1966	39%	6.5 – 9.8
9	Mississippi	2,406	8	1976	51%	7.2 – 11.7
10	Virginia	2,201	20	1971	42%	5.2 – 8.6
11	Ohio	2,198	16	1964	31%	3.4 – 5.9
12	North Carolina	2,113	13	1968	40%	4.6 – 7.9
13	Maryland	2,081	9	1966	53%	5.5 – 9.6
14	New Jersey	1,897	6	1969	28%	3.5 – 5.4
15	New York	1,502	12	1962	51%	4.2 – 7.0
16	West Virginia	1,465	3	1975	49%	4.7 – 7.4
17	Kentucky	1,391	10	1965	42%	2.9 – 5.1
18	Iowa	1,268	17	1967	41%	4.2 – 6.2
19	Pennsylvania	1,179	14	1983	73%	4.5 – 7.7
20	Nebraska	922	8	1967	54%	3.5 – 5.5

[a] Data for average online year and average capacity factor reflect weighted averages based on total state capacity.

[b] The low end of the avoided annual CO_2 emissions range reflects replacement of coal with existing natural gas (still a carbon-based fossil fuel), and the high end of the range reflects replacement of coal with zero-carbon-dioxide-emitting resources such as wind, or by reduced demand due to energy efficiency.

in-state generation from coal in 2010. West Virginia, Kentucky, and Indiana each generated more than 90 percent of their electricity from coal, although some of that power is exported to other states. The states with the most ripe-for-retirement coal generators are also some of the most dependent on imported coal. In 2008, 25 of the states (81 percent) that are top users of coal were also net importers of coal from other states or even other countries (Deyette and Freese 2010). Indeed, 16 states were dependent on imports for virtually all of the coal their power plants burned.

Low-Estimate State Results

Table 4 ranks the top 20 states by total capacity of the 153 generators we deemed ripe for retirement under the low estimate, and summarizes key state results.[18]

[18] See Appendix C for a table that ranks and summarizes results for all 28 states containing the 153 coal generators in our low estimate that are ripe for retirement.

Table 4. Top 20 States With the Most Ripe-for-Retirement Coal Generation Capacity (Low Estimate)

Rank	State	Capacity (MW)	No. of Coal Generators	Average Online Year[a]	Average Capacity Factor	Avoided CO_2 Emissions (million tons)[b]
1	Georgia	3,997	14	1968	56%	11.9 - 18.7
2	Florida	1,628	6	1974	46%	4.4 - 6.6
3	Mississippi	1,438	4	1975	49%	4.3 - 6.3
4	Michigan	1,190	16	1962	40%	3.8 - 5.3
5	Alabama	1,159	7	1957	44%	2.9 - 4.4
6	South Carolina	907	6	1962	22%	1.1 - 1.7
7	Virginia	899	10	1970	48%	3.0 - 4.3
8	Wisconsin	678	9	1957	46%	2.5 - 3.6
9	Pennsylvania	651	10	1990	87%	3.2 - 4.9
10	Iowa	507.6	12	1965	28%	1.8 - 2.3
11	Missouri	446.5	8	1965	51%	1.6 - 2.4
12	New York	406.6	6	1960	36%	1.4 - 1.8
13	Minnesota	343.3	7	1961	37%	1.2 - 1.6
14	Ohio	283.5	5	1952	4%	0.1 - 0.2
15	North Carolina	251.7	5	1988	21%	0.5 - 0.7
16	Kentucky	216	4	1957	48%	0.7 - 1.1
17	New Hampshire	213.6	3	1957	71%	1.0 - 1.6
18	Colorado	204.3	3	1975	78%	1.4 - 1.9
19	Tennessee	175	1	1954	26%	0.2 - 0.4
20	Nebraska	167.8	2	1979	50%	0.7 - 1.0

[a] Data for average online year and average capacity factor reflect weighted averages based on total state capacity.

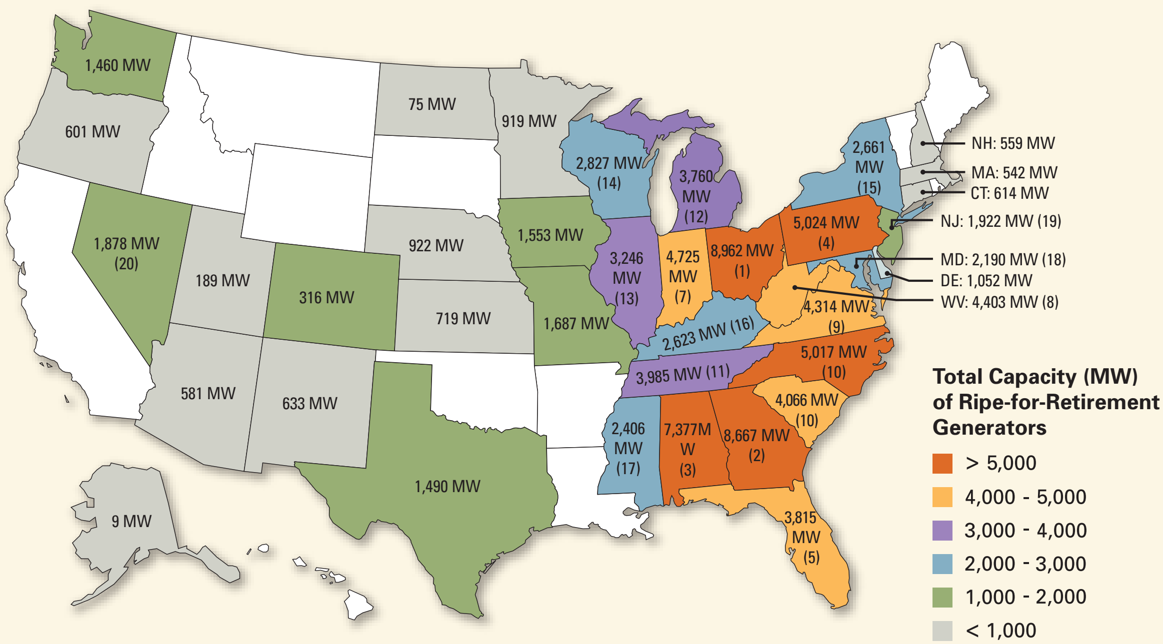
[b] The low end of the avoided annual CO_2 emissions range reflects replacement of coal with new natural gas (still a carbon-based fossil fuel), and the high end of the range reflects replacement of coal with zero-carbon-dioxide-emitting resources such as wind, or by reduced demand due to energy efficiency.

As in the high estimate, states from the Southeast and Midwest dominate the rankings, both in total capacity and the number of economically vulnerable generators. One of the key differences in the rankings is that three fewer states have generators that make the list under the low estimate: Arizona, Connecticut, and Delaware. In addition, Pennsylvania notably moves from nineteenth in terms of total capacity under the high estimate to ninth under the low estimate, indicating that a high percentage of its coal fleet is economically vulnerable compared with both new and existing natural gas power plants.

Combined Results

As discussed in Chapter 2, coal plant owners in many states have already decided to retire their most economically underperforming generators. When those 288 generators already slated for retirement are

Figure 12. 39 States* Ranked by Capacity of Coal Generators Announced to Be Retired or Identified as Ripe for Retirement (High Estimate)



Coal generators in 39 states have either been scheduled for retirement or identified as ripe for retirement under our high estimate. Eighteen states have more than 2,000 MW of generating capacity that falls under both categories. Ohio leads all states with nearly 9,000 MW of coal generating capacity that is ripe for retirement, followed by Georgia with nearly 8,700 MW.

* Rankings for top 20 states listed in parentheses.

combined with our list (the high estimate) of 353 additional generators that are economically vulnerable, there are 39 states with 100.2 GW of coal generating units that have either announced retirements or have been identified as ripe for retirement (Figure 12).

Table 5 ranks the top 20 states[19] by total combined capacity of coal generators already scheduled for retirement plus our high estimate of additional ripe-for-retirement generators. Eighteen of these states have more than 2,000 MW of generating capacity that fall under both categories. While many of the states in the top 10 remain the same as in our high estimate, several states moved up in rank as a result of significant recent announcements of uneconomic generators to be retired. For example, with nearly 6,800 MW in announced retirements—more than any other state—Ohio moves to the top of Table 5. Likewise, Pennsylvania moved up from nineteenth to fourth as a result of announcing

There are 39 states with 100.2 GW of coal generating units that have either announced retirements or have been identified as ripe for retirement.

[19] See Appendix C for a table that ranks and summarizes results for all 39 states, combining both the generators already slated for retirement with our high estimate of additional generators ripe for retirement.

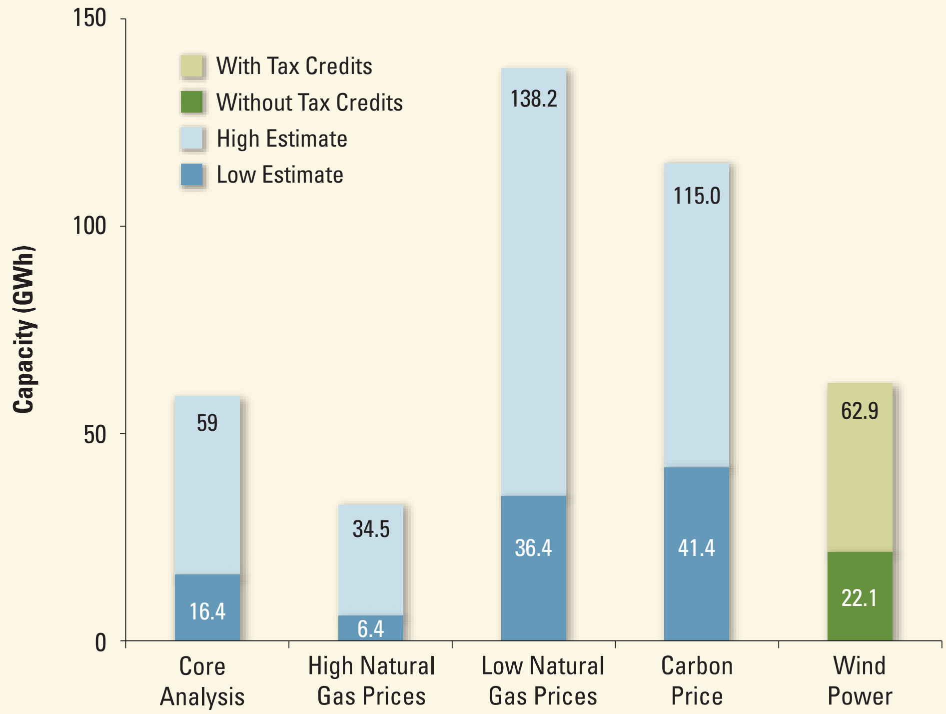
Table 5. Top 20 States Ranked by Combined Capacity of Coal Generators Announced for Retirement and Identified as Ripe for Retirement (High Estimate)

Rank	State	Combined Total		Announced Retirements		Ripe for Retirement (High Estimate)	
		Capacity (MW)	No. of Coal Generators	Capacity (MW)	No. of Coal Generators	Capacity (MW)	No. of Coal Generators
1	Ohio	8,962	59	6,763	43	2,198	16
2	Georgia	8,667	26	1,257	4	7,411	22
3	Alabama	7,377	30	844	6	6,534	24
4	Pennsylvania	5,024	40	3,845	26	1,179	14
5	North Carolina	5,017	39	2,904	26	2,113	13
6	Florida	4,998	15	1,183	4	3,815	11
7	Indiana	4,725	40	2,293	24	2,431	16
8	West Virginia	4,403	21	2,938	18	1,465	3
9	Virginia	4,314	34	2,114	14	2,201	20
10	South Carolina	4,066	26	1,125	15	2,942	11
11	Tennessee	3,985	23	125	1	3,860	22
12	Michigan	3,760	41	112	2	3,648	39
13	Illinois	3,246	25	2,423	17	823	8
14	Wisconsin	2,827	26	377	8	2,450	18
15	New York	2,661	21	1,160	9	1,502	12
16	Kentucky	2,623	19	1,233	9	1,391	10
17	Mississippi	2,406	8	-	-	2,406	8
18	Maryland	2,190	11	110	2	2,081	9
19	New Jersey	1,922	7	25	1	1,897	6
20	Nevada	1,878	3	1,878	3	-	-

3,845 MW in retirements, possessing a combined total of 5,024 MW in announced retirements and additional uneconomic, ripe-for-retirement generators.

Both Texas and Nevada each have more than 1,000 MW in announced retirements. In Texas, three generators totaling 1,490 MW are already slated for retirement. The state's remaining generators did not make our ripe-for-retirement list, despite the fact that more than half of them are missing adequate emissions controls for three or more pollutants. The Texas generators are typically larger, newer, and operated more frequently than the nationwide average, giving them a stronger competitive advantage in dealing with the cost of installing conventional pollution controls. However, other important factors should be considered that may lead some of their owners to retire them rather than retrofit them anyway, including the needs to cut carbon dioxide emissions and to install cooling towers to address significant water resource needs in a drought-prone state.

Figure 13. Coal Generating Capacity Deemed Ripe for Retirement under Alternative Scenarios



Alternative scenarios explore three external economic factors that could influence the coal-fired generating capacity deemed ripe for retirement. In the core analysis (far left), the low estimate (dark blue alone) compares the operating cost of coal generators with the operating cost of a *new* NGCC plant; the high estimate (combined dark blue and light blue) compares the operating cost of coal generators with the operating cost of *existing* NGCC plants whose capital costs are largely amortized. The middle three bars repeat the analysis for hypothetical scenarios where natural gas prices might be 25 percent higher or 25 percent lower, or where a $15/ton price might be put on carbon dioxide emissions. For the wind power scenario (far right), the analysis illustrates the capacity of coal-fired generators deemed ripe for retirement if federal tax credits for wind power are allowed to expire (dark green) or are extended (combined dark green and light green). Our analysis reveals that low natural gas prices and a price on carbon dioxide have the greatest impact in expanding the pool of coal-fired generators deemed ripe for retirement, and that extending the federal tax credits for wind power is also significant.

Findings from Alternative Scenarios

Numerous external factors could play a significant role in determining the future economic viability of the coal fleet nationwide and, by extension, the number of coal generators deemed economically ripe for retirement. We explored three factors: a high and low price for natural gas, a price on carbon, and the possibility of an extension or expiration of federal tax credits for wind power. Figure 13 compares the total capacity of ripe-for-retirement generators under each of these alternative scenarios with the high and low estimates from the core analysis.[20]

Natural gas prices. Although many experts project that natural gas prices will remain relatively stable over

[20] See Appendix D for a summary table of the alternative scenarios results.

the next several years, uncertainties in the power market as well as in fuel supply and demand could drive prices higher or lower in the future. Regional prices also differ from the national average. Our core analysis assumes a national 20-year levelized natural gas price of $4.88/MMBtu for both existing and new NGCC units, based on the EIA's reference case projections for the electricity sector in its *Annual Energy Outlook 2012* (EIA 2012c). The low natural gas price scenario assumes a 25 percent decrease in the EIA's reference case projections ($3.66/MMBtu), while the high price scenario represents a 25 percent increase in the EIA projections ($6.10/MMBtu).

Varying natural gas prices have a substantial impact on the amount of coal generating capacity that remains economically competitive with natural gas generating capacity. For example, when comparing coal with an existing NGCC facility under the low price scenario, the total capacity of economically vulnerable coal generators grows to 138.2 GW—more than double the high estimate of 59 GW in our core analysis results. The additional coal generators flagged as ripe for retirement under the low natural gas price scenario tend to be more productive, generating electricity at higher capacity factors than the core analysis retirements. Indeed, at an estimated 651 million MWh, the total annual coal generation designated as ripe for retirement in the low price scenario is nearly three times greater than the high estimate of the core analysis. In contrast, if natural gas prices were to increase compared with the core analysis, fewer coal generators would be economically vulnerable compared with natural gas. Under the high natural gas price scenario for an existing NGCC facility, the total capacity of generators deemed ripe for retirement declines by 41 percent (from 59.0 GW to 34.5 GW), representing a decrease in total generation of 50 percent (from 225 million MWh to 113 million MWh).

A price on carbon. The carbon price scenario uses a conservative CO_2 price of $15 per ton as a generic proxy for potential future policies or regulations to address global warming emissions.[21] Based on smokestack emissions only,[22] new NGCC plants typically produce approximately half the CO_2 emissions per megawatt-hour of power generated by new coal plants, and 36 percent of the average CO_2 emissions for the existing U.S. coal fleet. As a result, placing a price on carbon has a greater impact on the cost of electricity generated from coal than from natural gas. Conversely, zero-carbon renewable energy sources such as wind and solar would realize an even bigger cost advantage because they emit no carbon dioxide.

Low natural gas prices, a price on carbon, and extending the federal tax credits for wind power each have a great impact on expanding the pool of ripe-for-retirement coal-fired generators.

Under the carbon price scenario, the coal generating capacity that is economically vulnerable nearly doubles from 59 GW to 115 GW when compared with existing natural gas power generating capacity. If all that additional coal generating capacity were retired, annual CO_2 emissions would be reduced by 348 million tons, which is 14 percent of 2010 U.S. power sector emissions—more than twice the reductions in annual CO_2 emissions under the core analysis for existing natural gas power plants. The avoided CO_2 emissions would likely be even higher, assuming that wind power and new NGCC facilities replace some of the closed coal generators.

None of the potential reductions discussed above include the 88 million to 150 million tons of CO_2 emissions reductions that will occur from shutting down the 41 GW of coal generators already on the announced retirement list.

Extended tax credit for wind. Our analysis also evaluates the economic viability of coal compared with wind power. We found that wind power costs are competitive enough to force a significant number of coal generators over the threshold of being ripe for retirement, but how many depends greatly on the status of

21 Our carbon price assumption is based on the low-cost case from a 2011 meta-analysis by Synapse Energy Economics, which reviewed more than 75 different scenarios from recent modeling analyses of various climate policies (Johnston et al. 2011). It is also consistent with what the EIA assumes in its modeling and long-term energy projections for the United States when evaluating investments in coal plants and other carbon-intensive technologies, and with what many utilities and regulators use in resource planning (EIA 2010).

22 The extraction of natural gas using hydrofracking technology and the transport of natural gas in pipelines creates the potential for significant additional global warming emissions. For more information, see box, "What Are the Risks of an Over-Reliance on Natural Gas?" in Chapter 4.

the federal production tax credit for renewable energy. The PTC, which provides a 20-year levelized value of two cents per kilowatt-hour, is set to expire at the end of 2012 (Wiser and Bolinger 2011). Our core analysis compares the economics of coal generators with the cost of wind minus the tax credit (that is, assuming the PTC expires), while the alternative scenario assumes that the PTC is extended.

Without the PTC, 22.1 GW of coal generating units meet the ripe-for-retirement threshold. With the added financial support from extending the PTC, nearly triple that coal-generated capacity—62.9 GW—would become economically vulnerable compared with wind. These results are consistent with the findings from the low and high estimates of the core analysis, which compares the cost of generating electricity from coal versus from natural gas. That is because in an average wind resource area, the cost of producing electricity without the PTC is generally competitive with the cost of a new NGCC unit (the comparison threshold for our low estimate). Also, unlike coal (which must be mined and transported) and natural gas (which must be drilled and transported), the wind blows for free. However, additional transmission and integration costs, lower capacity values, and limited ability to control when wind turbines generate power all contribute to the need for additional incentives if wind power is going to compete on a level playing field with fossil fuels, whose environmental and health costs are not fully reflected in their power costs. With the PTC, wind power costs are generally more comparable to the costs of an existing NGCC facility (the comparison threshold for our high estimate).

Because wind generation emits no CO_2 or other harmful pollution, however, the avoided CO_2 emissions associated with replacing coal with wind are substantially higher than with natural gas. The scenario of wind including the PTC would reduce annual CO_2 emissions by 279 million tons, a more than 75 percent increase over the CO_2 reductions that would occur if all 353 coal generators identified in our high estimate were retired and their power replaced by existing natural gas facilities. In addition, the United States has tremendous wind resource potential, far exceeding the potential for excess existing natural gas capacity to replace coal generation (Bradley et al. 2011; EERE 2008).

The United States has tremendous resource potential for wind, far exceeding the potential for excess existing natural gas capacity to replace coal generation.

Limitations and Uncertainties

The U.S. electric power system is dynamic, complex, and constantly changing in response to various domestic and international influences. Any macro-level economic analysis seeking to determine the future decisions of individual power providers is inherently uncertain. Our analysis is not a prediction of what will happen to the U.S. coal power fleet, but rather an effort to identify which coal generators are most vulnerable to the current and near-term economic conditions in the power market. In pursuit of that goal, we note that four key factors limit our analysis or create uncertainty:

- Data limitations
- National-level assumptions
- Clean Air Act standards
- Dynamic power markets

Data limitations. Our analysis relies on generator-level data reported annually by facility operators to the EPA and the EIA. While these data are accurate and current to the best of our knowledge, errors in data reporting or processing could affect our results. Moreover, in several situations, relatively small amounts of incomplete, unreported, or inconsistent data limited the scope of the results or required us to make simplifying assumptions or other changes to our methodology. For example, there were 204 coal generators (30.3 GW) that lacked net generation or capacity factor data. As a result, their operating costs could not be estimated and we excluded these generators from our analysis. Based on their average age and size, some subset of these generators would likely be considered ripe for retirement if sufficient data were available to evaluate.

We also relied on EPA data to identify the presence of a specific pollution control technology at an individual generator and then merged that information with additional data about the generator from the EIA. However, the EPA bases its data on individual coal-fired boilers, whereas the EIA reports at the generator level (which could be tied to multiple boilers). In the few cases where boiler-level data from the EPA did not precisely match generator data from the EIA, we made attempts to reconcile the differences. Furthermore, some coal owners have more recently completed or made commitments to retrofit generators with pollution controls—data that have not been captured in the EPA's database. Where we had direct knowledge of such situations, we adjusted our analysis accordingly.

National assumptions. Our analysis evaluates the economics of coal at the generator level, but a lack of consistent and reliable unit-specific or regional data requires that many of our cost and performance assumptions be based on averages or other national-level information. For example, all cost and performance assumptions for natural gas and wind are for a typical, nationally representative facility. We also used national average heat content and fuel cost data depending on the type of coal burned to estimate base running costs when plant-level data were unavailable. While this methodology is generally consistent with other analyses, small changes in any assumption could have a significant impact on the results—potentially either adding or removing generators from our lists of ripe-for-retirement generators.

Our analysis does not examine compliance with Clean Air Act standards but instead estimates the cost effects of modernizing the coal fleet by installing the most effective pollution control technologies available.

Clean Air Act standards. Our analysis is not an evaluation of the coal industry's compliance with Clean Air Act (CAA) standards. Instead, it estimates the cost effects of modernizing the coal fleet to meet current public health standards by installing the most effective pollution control technologies available. While the technologies we selected are generally consistent with what most coal generators would need to comply with CAA standards, some plants could meet the standards by employing other combinations of control equipment or pursuing a variety of policy-related mechanisms (e.g., emissions trading markets) that we did not consider. In addition, while not all of the air regulations apply nationwide—for example, the Cross State Air Pollution Rule (CSAPR, see Appendix B) only applies to the eastern half of the nation, where most coal plants are located—we analyzed the cost of modernizing the coal fleet with pollution controls across all states.

Furthermore, while our analysis examines the cost of cutting emissions of SO_2, NO_X, particulate matter, mercury, and CO_2 (in an alternative scenario), we did not evaluate the costs associated with reducing the impacts from other environmental and public health concerns regulated by the federal government, such as toxic ash handling and cooling towers. Collectively, these factors differentiate the results of our analysis from what could occur under pending federal CAA standards, and consequently, introduce some level of uncertainty within the findings once the new standards take effect. To the extent that CAA regulations increase coal generator operating costs, our analysis may underestimate the number of economically vulnerable coal generators that should be considered ripe for retirement.

Dynamic power markets. Power markets are continually changing because of a host of economic, political, and consumer-driven influences. A change in consumer demand could increase or decrease the market price of electricity and subsequently alter the profitability of a given coal generator. For example, growing demand for power globally and other factors have contributed to rising coal prices in recent years. If that trend continues, additional coal generators could face economic constraints. Likewise, increased investments in efficiency or demand-side management could reduce consumer demand for electricity and influence decisions about retiring coal generators.

We did not analyze such dynamic power market fluctuations. Nor do we consider potential cost shifts for different technologies or other market changes over time. Ours is a static analysis, comparing a snapshot of costs and market conditions as they currently exist. In reality, however, retiring uneconomic plants and replacing them with cleaner alternatives will happen over a period of several years. In addition, factors other than operating costs will influence which coal generators actually end up being retired: including their location in the power grid, what alternative energy sources are specifically available to replace them, whether transmission lines are available to connect wind projects and other replacement resources, whether the generators are operating in regulated or deregulated electricity markets, and how investors are accounting for future costs. Each of these factors provides important opportunities for future research.

CHAPTER 4
We Can Do It!

Retiring as many as 641 coal-fired generators accounting for 100.2 GW—288 (representing 41.2 GW) already slated for retirement plus up to 353 in our high estimate (representing 59 GW) identified as ripe for retirement—is not trivial. Collectively, those generators supply enough power to meet 10 percent of national electricity use—more than enough to satisfy the combined needs of Florida and Georgia (EIA 2012d).

The nation's electricity system is well prepared to continue providing reliable, affordable power while retiring and replacing 100.2 GW of coal generators over the next several years.

The Good News

The nation's electricity system is well prepared to continue providing reliable, affordable power while retiring and replacing these coal generators over the next several years. There are several reasons the system can readily handle so many retirements:

Excess generating capacity. According to data from the North American Electric Reliability Corporation (NERC), the United States is projected to have 145.7 GW of excess capacity by 2014. That excess capacity is above and beyond the 12.5 to 15 percent reserve margins (excess capacity above peak energy demand) required to maintain reliability at the regional level (Bradley et al. 2011). Thus, in the near term, significant coal capacity can be retired without the need to replace it with any new generation. However, we recognize that local reliability constraints may require that some uneconomic units continue to run until other solutions, like new low-carbon generation or transmission system improvements, are made.

Underutilized natural gas capacity. The nation's 220 GW fleet of NGCC power plants operated at an average of just 39 percent of its design capacity in 2010 (SNL Financial 2012). Running those plants at higher capacity has the potential to immediately replace most of the retired coal generation projected under our high estimate in almost all regions of the country (discussed below).

State renewable energy policies. Renewable electricity standards in place in 29 states are driving major increases in wind, solar, geothermal, and bioenergy facilities. From 2012 through 2020, these standards are projected to spur the installation of 55 GW of new renewable energy capacity that will produce enough additional generation to meet 5 percent of U.S. electricity use by 2020 (UCS 2012).

Declining renewable electricity prices. Wind power is already competitive with new coal plants and with natural gas in the windiest parts of the country (Freese et al. 2011; Wiser and Bolinger 2011). The installed cost of solar photovoltaics (PV) has fallen 35 percent in the last two years, while solar panel prices have fallen by more than 50 percent (SEIA 2012).

State energy efficiency policies. Energy efficiency policies and goals now in place in 27 states are projected to reduce national electricity use 5.7 percent by 2020 (UCS 2012). Many studies show that energy savings exceeding 15 percent by 2020 are possible, using only energy-efficient technologies that pay for themselves (ACEEE 2012; Granade et al. 2009).

Maintaining reliability. Each coal generator will be retired in the context of regional and national grid management systems that require exhaustive reliability planning. Long before a coal plant stops producing power, grid operators will work with generation and transmission providers to ensure that electricity supplies will continue uninterrupted. In addition, we do not believe that coal generators would retire all at once, but would be shut down in an orderly manner over several years, consistent with regional reliability plans.

Transmission planning. New federal regulations such as Federal Energy Regulatory Commission (FERC) Order No. 1000 will help level the playing field for cleaner resources by requiring transmission planners to consider state and federal policies such as efficiency and renewable electricity standards, to provide comparable treatment to non-transmission alternatives (options that free up or create capacity without requiring transmission lines, such as energy efficiency, demand-response measures, distributed generation, and energy storage options), and to develop coordinated plans that more broadly allocate costs for transmission projects driven by public policies.

Both during and beyond the wave of coal retirements that will occur over the next decade, there is well-documented potential for the additional expansion of renewable energy sources and decreased demand for electricity through energy efficiency, while maintaining reliability and saving consumers money on their electricity bills (DOE 2012; Cleetus et al. 2009; SACE 2009; UCS 2009; EERE 2008; Nogee et al. 2007). Beyond 2020, renewable sources and decreased demand can steadily replace the remaining U.S. coal-fired generator fleet, and eventually power a shift away from most natural gas as well.

Change Is Already Under Way

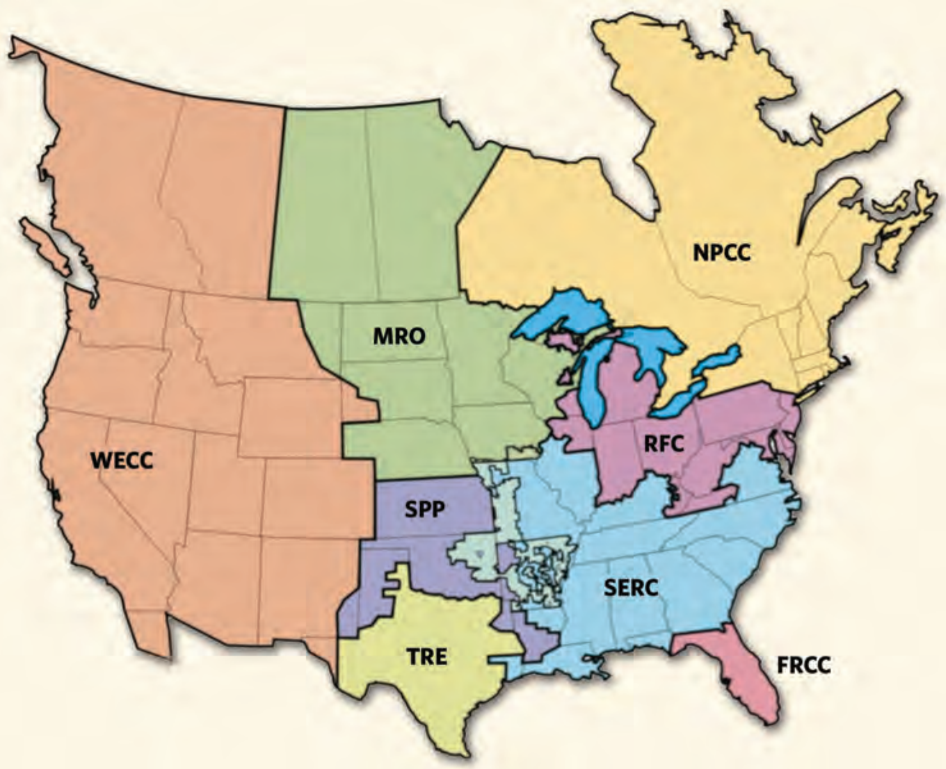
By the electricity industry's own reckoning, it is in the midst of unprecedented change as cleaner energy sources replace coal (NERC 2011). This change is appropriate given the societal benefits of limiting coal's impact on air and water quality and public health. As shown by our analysis in Chapter 3 and many independent reports, it has been clear for some years that large numbers of coal generators are marginally economic at best. Given that outlook, it is not surprising that the ramifications of extensive coal plant retirements for the nation's electricity grid have already been examined in depth. At least 20 studies in the last two years have investigated scenarios ranging from 25 GW to 103 GW of coal units retired (Cleetus 2012). With 41 GW of retirements already announced, the United States is already well on its way to fulfilling these projections.

Both during and beyond the wave of coal retirements that will occur in the next decade, there is well-documented potential for the additional expansion of renewable energy sources and decreased demand for electricity through energy efficiency, while maintaining reliability and saving consumers money on their electricity bills.

These recent studies broadly conclude that the retirement of a large number of coal units is likely and, with some planning, can be accomplished while providing cleaner, reliable, and affordable electricity. For example:

- The nonpartisan Congressional Research Service and others have debunked industry claims that cleaning up pollution from coal plants will lead to a "train wreck" of hastily shuttered generators and blackouts (McCarthy and Copeland 2011; Kaplan 2010).
- Investment banks have reported that large-scale retirement of old, inefficient coal units could benefit some utilities and other power plant owners by reducing the current surplus of capacity (e.g., Lapides et al. 2011; Eggers et al. 2010; FBR Capital Markets 2010).
- Energy consultants have shown that the regions of the country with the greatest concentrations of uncompetitive coal-fired generators—the Southeast, Mid-Atlantic, and Midwest (regions RFC and SERC in Figure 14)—have large cushions of excess capacity on top of required reserves (Bradley et al. 2011; MIT 2011; Swisher 2011).
- A 2011 report by PJM Interconnection LLC, which manages the electricity grid in 13 Midwest and Mid-Atlantic states, concluded that, "As long as resource adequacy and local reliability are assured, the cycle of generation retirement and new resource entry are market-driven outcomes that can be reliability and efficiency enhancing" (PJM 2011).

Figure 14. North American Electric Reliability Corporation (NERC) Regions



NERC works with eight regional entities to improve the reliability of the bulk power system. The members of the regional entities come from all segments of the electric industry and account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The eight NERC regions are the Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RFC), SERC Reliability Corporation (SERC), Southwest Power Pool (SPP), Texas Reliability Entity (TRE), and the Western Electricity Coordinating Council (WECC).

Source: *http://www.nerc.com.*

Replacing Coal

While figures on national-level changes in electricity generation or demand can give important information about long-term trends, it is at the regional and local levels that electricity supply and demand must be kept in balance. Figure 14 shows the major reliability regions in the U.S. power grid. Long-distance power lines in many parts of the country allow electricity to be generated in one region and used in another. While major transmission projects are under way to expand these linkages both within and across regions over the next decade, for the present most of each region's electricity demands will be met with power generated from within that region. Eventually, a more interconnected grid will help boost and diversify the resources available to meet demand and maintain reliability in a given region.

Excess capacity. To ensure that enough generation capacity is available to meet electricity demands reliably, NERC mandates that regional power grid operators maintain electricity reserve margins within each region ranging from 12.5 percent to 15 percent above maximum projected demand. This provision allows the system to cope with above-normal fluctuations in demand or outages in generation or transmission equipment. In 2014, actual reserve margins at the regional level are projected to increase to a range of 28 percent to 40 percent, which is far above the required reserve margins. That will create excess capacity (above required reserve margins) at the national level totaling about 145 GW (Bradley et al. 2011; NERC 2011). This cushion of excess capacity has developed for several reasons. A boom in natural gas power plant construction from the late 1990s through the early 2000s, driven by low natural gas prices and technology advances, resulted in significant natural gas capacity that has subsequently gone largely underutilized. Just from 2001 through 2003, more than 160 GW of new capacity (mostly natural gas) came online in the United States (Bradley et al. 2010). Renewable energy capacity has also increased significantly, with wind power leading the way, providing 35 percent of all new U.S. electric generating capacity from 2007 through 2010 (Wiser and Bollinger 2011). The economic downturn that began in 2008 combined with increased investments in energy efficiency has also resulted in a significant drop in electricity demand. Programs where large factories and businesses, as well as smaller residential consumers, agree to reduce their use during periods of peak demand, such as hot summer afternoons, have also played a role in managing demand (Bradley et al. 2011).

As Figure 15 shows, in every region of the country except the Southeast (SERC), the projected excess capacity for 2014 exceeds the combined capacity of both the coal units already scheduled to be shut down and the additional units we deem ripe for retirement. Although this comparison does not assess potentially important issues such as local limitations on electricity transmission and plants that serve important reliability needs, it shows that, broadly speaking, in most regions of the country the vast majority of the projected retirements could occur within the next two years without compromising generation reserve margins. Even in the SERC region, the reserve margin gap is a relatively modest eight gigawatts.[23] Given that retiring all 100 GW of coal generation capacity would almost certainly take longer than two years, recent history shows there is ample time to build any needed replacement generation and further reduce peak demand through efficiency and load management.

Underused natural gas plants account for most of the nation's excess generation capacity. On average in 2010, the 220 GW existing NGCC power plant fleet operated at just 39 percent of its design capacity (SNL Financial 2012). We estimate that running these plants at 85 percent of their design capacity has the potential in all regions of the country—including the Southeast—to immediately replace most of the coal generators deemed ripe for retirement under our high estimate (Figure 16, p. 54). Studies by the Congressional Research Service, the Massachusetts Institute of Technology, and others have reached similar conclusions (MIT 2011; Swisher 2011; Kaplan 2010).

In every region of the country except the Southeast (SERC), the projected excess electricity capacity (above required reserve margins) for 2014 exceeds the combined capacity of both the coal units already scheduled to be shut down and the additional ripe-for-retirement units.

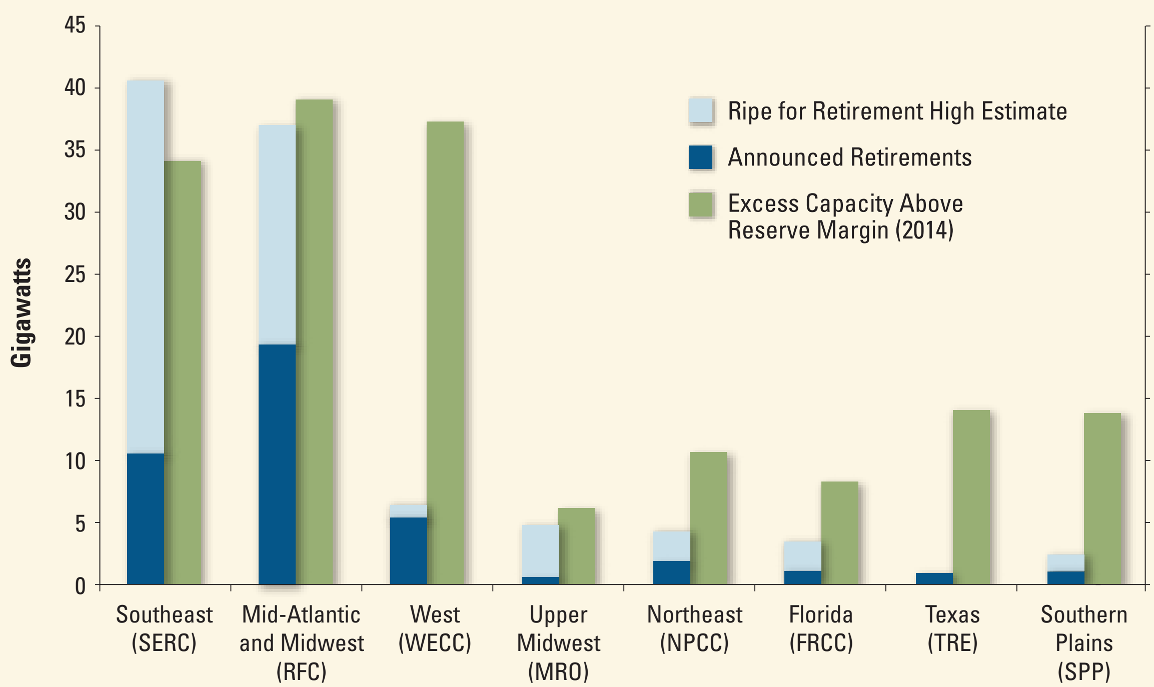
New capacity. New natural gas plants also continue to be developed in response to favorable economics and official projections that U.S. electricity demand will continue to grow at roughly 1 percent per year through 2020 and beyond. Through 2017, NERC estimates that 42 GW of natural gas generating capacity now in planning or construction will come online, with the potential for an additional 38 GW if utilities and power developers move forward with additional projects currently in conceptual stages. By 2021, NERC also projects U.S. wind capacity to grow by 36 GW and solar by 28.5 GW (NERC 2011). PJM recently reported that its annual capacity auction for resources to meet power supply needs between June 1, 2015, and May 31, 2016, secured record amounts of new generation (natural gas, wind, and solar), demand response, and energy efficiency. As one of the most coal-dependent electricity grids facing a high number of potential coal plant retirements, PJM is demonstrating that it is possible to handle the shift away from coal effectively, efficiently, and reliably (PJM 2012).

[23] In the Southeast nuclear power is also expected to play a role as coal plants are retired. Currently there are four new reactors planned for construction in Georgia and South Carolina totaling 4,400 MW, which along with the completion of the Watts Barr plant in Tennessee (1,100 MW) could help replace existing coal plants and contribute to reserve margins in the region. However, the current schedules for completion of these reactors cannot be counted on due to recent and likely future construction delays that could keep some of these plants from coming online as planned, beginning with Watts Barr in 2015 and Vogtle 3 and 4 in 2016 and 2017, respectively. In addition, we have found that there are more affordable, less risky energy alternatives that the Southeast could benefit from, including ramping up renewable energy and investing in energy efficiency (Chang et al. 2011).

Natural gas generation can play an important transitional role in integrating wind and solar into the national power generation mix. Natural gas plants are capable of quickly increasing or decreasing their power output—in seconds to minutes. Similar increases or decreases to the output of a coal or nuclear plant can take hours or even days. Thus, natural gas plants are a good complement for wind and solar energy as the market share of those clean renewable sources continues to increase, reducing power output when the wind is blowing and the sun is shining and increasing output when it is not. However, investing in significantly scaling up new renewable generation and energy-saving technologies[24] is essential to keep the nation from placing a dangerously large bet on natural gas generation, which comes with significant environmental, health, and climate change risks (see box, p. 60).

Although gridlock in Washington has so far stymied development of strong national renewable energy and energy efficiency policies, states are making meaningful progress. While support for renewable energy and energy efficiency varies from state to state, two types of

Figure 15. Projected Cushion of Excess Capacity above NERC-required Electricity Reserve Margins in 2014, Compared with Projected Coal Plant Retirements*



Coal generators currently slated for retirement plus those identified as ripe for retirement can be shut down with minimal risk to regional electricity reserve margins. As the chart shows, in every region of the country except the Southeast (SERC), the projected excess capacity for 2014 (green bar) exceeds the combined capacity of coal plants that could be retired (blue bars).

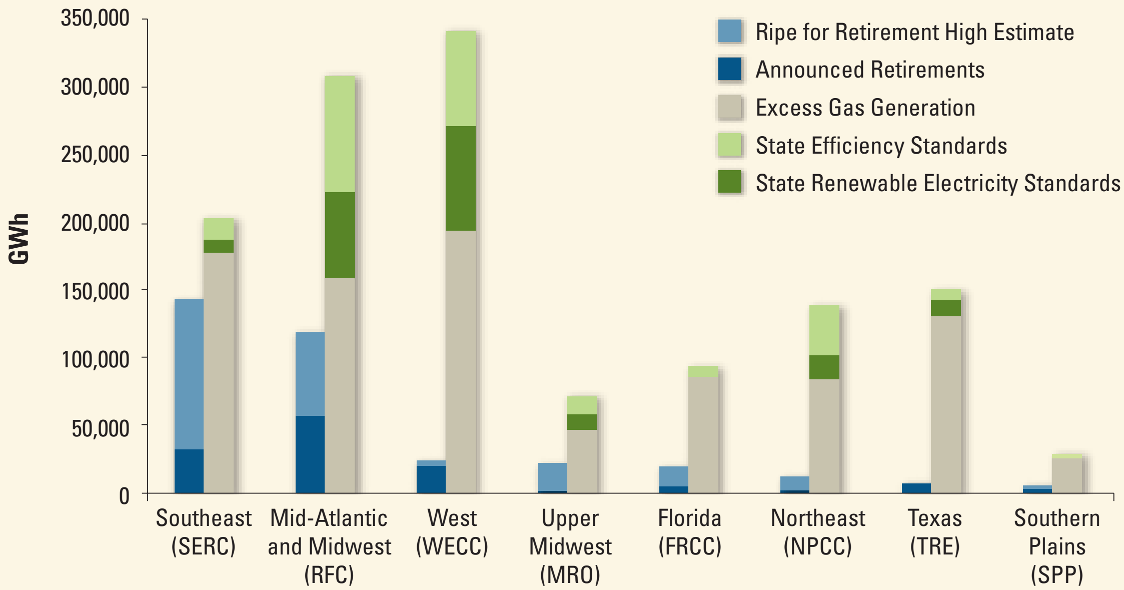
* NERC oversees reliability for a bulk power system that includes the United States and Canada. In this effort, NERC coordinates with eight regional entities to maintain and improve the reliability of the power system (see Figure 14). "Excess capacity above reserve margin" is the amount of installed capacity that exceeds what is required to maintain reliability or the NERC reserve margin; this represents additional capacity that is not required for reliability and subsequently could be used to offset any reductions in electricity production from coal retirements.

[24] See Cleetus et al. 2009 for a more detailed description of different renewable energy and efficiency technologies.

policies have been adopted widely and are driving new investment: energy efficiency resource standards and renewable electricity standards (or renewable portfolio standards). In addition, some states and regions have adopted cap-and-trade programs that limit carbon dioxide emissions and provide economic incentives to encourage sources of clean power generation.

- *Energy efficiency resource standards (EERS)* set a timeline for a state's utilities to meet a growing percentage of their customers' power needs by investing in energy-saving technologies that reduce overall electricity use. Ratepayers in a given state typically fund energy efficiency programs through a small additional fee on their monthly electricity bills. When implemented effectively over time, EERS programs slow the rate of growth in energy demand and help keep down both electricity prices and consumer bills. As of October 2011, 24 states had adopted an EERS or similar programs, while three states have voluntary efficiency goals (ACEEE 2011) (Figure 17). In addition, fully 35 states have either adopted or updated their building codes with new standards of insulation, heating and cooling

Figure 16. Renewable Energy, Energy Efficiency, and Existing Excess Natural Gas Can Readily Replace Retiring Coal Generation by 2020*



Shutting down the 353 generators that are ripe for retirement will have minimal impact on reliability. As the chart shows, every region of the country has the potential to replace the generation from both the 288 coal plants already slated for retirement (dark blue) and the 353 additional coal plants deemed ripe for retirement (light blue). Their combined capacity of 100.2 GW can be replaced through a combination of ramping up underused existing natural gas plants (gray), making use of new renewable energy generation, and reducing demand resulting from energy efficiency savings. The renewable energy generation and efficiency savings are projected to be developed over the next eight years (by 2020) as a result of existing policy requirements, including state-level renewable electricity standards (dark green) and energy efficiency resource standards (light green).

* The eight NERC entities are composed of utilities, federal power agencies, rural cooperatives, independent power marketers, and end-use customers. Excess natural gas generation capacity was estimated by determining the power produced if existing gas facilities increased electricity production to 85 percent of their capacity. State efficiency standards and renewable electricity standards are the GWh of savings or generation that would occur if state policy goals are met through 2020.

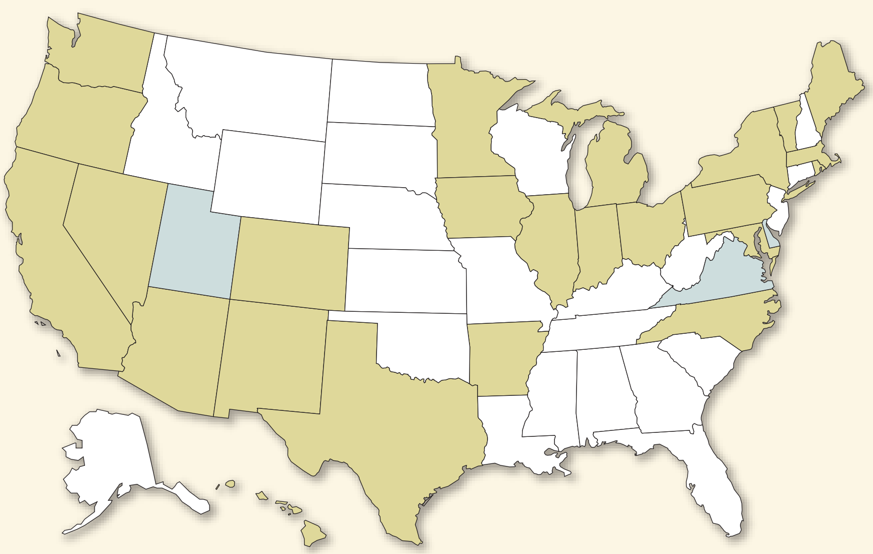
system efficiency standards, and other energy conservation requirements or have plans to do so, up from 17 states in 2010 (Nadel 2011). Reducing how much electricity is needed by homes and businesses helps avoid investing in far more costly new power plants and transmission lines. Moreover, because lower demand reduces the strain on existing power plants and transmission lines, the overall power grid benefits through improved reliability and reduced risk of outages.

- *Renewable electricity standards (RES)* typically require utilities to increase, over time, the percentage of electricity they supply to consumers from renewable sources. As of March 2012, 29 states and the District of Columbia had adopted an RES, with an additional eight states adopting non-binding renewable energy goals (Figure 18, p. 56) (UCS 2012). Seventeen states have adopted renewable standards with a target of 20 percent or more by 2025, including California, Colorado, Illinois, Minnesota, New Jersey, and New York. Eligible renewable sources generally include wind, solar, bioenergy, geothermal, and small-scale hydroelectric. Most states allow the standards to be met with renewable energy produced inside the state or delivered to the state from generators in other states in the region.

The combination of new renewable electricity generation and reduced demand through energy efficiency plus excess natural gas generation can more than offset the loss of power generation if all ripe-for-retirement coal units and those already announced for closure actually shut down.

- *State and regional cap-and-trade programs* include one in California and a separate one in nine northeastern states. A cap-and-trade program is one way to price carbon. The program sets a declining cap on overall emissions and issues allowances (the right to emit a certain number of tons of carbon pollution) to match the cap. By limiting the number of available pollution allowances, carbon emissions that were previously emitted for free now have a market value, which creates an economic incentive to reduce emissions. California's Global Warming Solutions Act (Assembly Bill 32) requires

Figure 17. States with Energy Efficiency Resource Standards (EERS)



Energy Efficiency Standard   Voluntary Goal

Energy efficiency resource standards, which require utilities to meet a growing percentage of their customers' power needs by investing in energy-saving technologies that reduce overall electricity use, have proven to be a popular and effective policy. Twenty-four states have adopted an EERS or similar programs, while three states have voluntary efficiency goals.

California to develop regulations that will reduce the state's global warming emissions to 1990 levels by 2020. To fulfill these requirements, the state is implementing several programs including an RES, a clean vehicles standard, and a cap-and-trade program. Across the country, the Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort to reduce global warming emissions in nine Northeast states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont). In addition to capping emissions, RGGI states are using the funds from the auction of allowances to invest in energy efficiency and renewable energy.

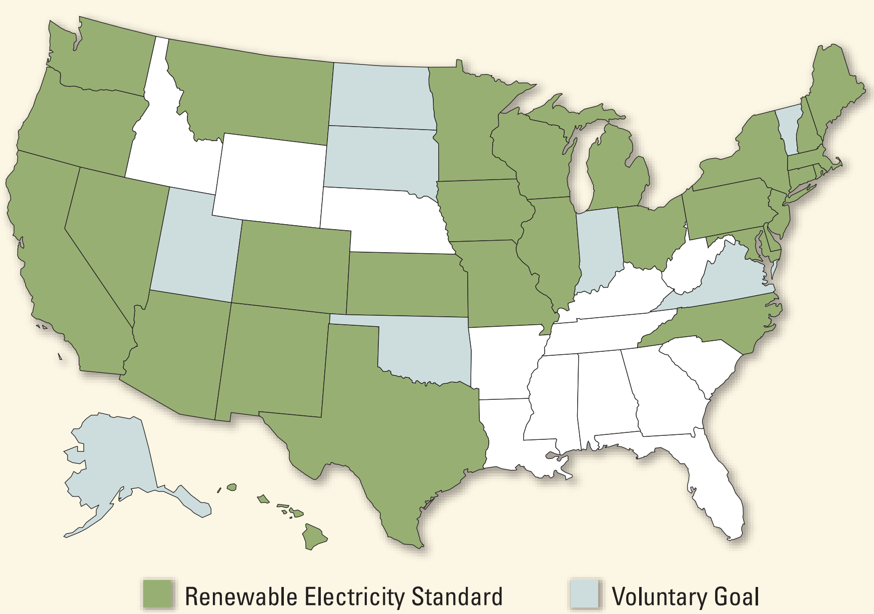
Over the next eight years (to 2020), we project that the combination of new renewable electricity generation and reduced demand through energy efficiency investments (driven by state clean energy policies) plus excess natural gas generation can more than offset the loss of power generation if all ripe-for-retirement coal units and those already announced for closure actually shut down. Our analysis shows that this conclusion applies at the national level and in every region (UCS 2012), as shown in Figure 16.

At the national level, renewable energy use is growing rapidly. In 2011, non-hydroelectric renewable energy sources (such as wind, solar, biomass, and geothermal energy) generated 4.7 percent of total U.S. electricity use, a 17 percent increase over 2010 (EIA 2012a). In the past decade, renewable energy sources have grown 175 percent.

Many analysts project the sector's rapid growth to continue (e.g., Pernick et al. 2012; Deutsche Bank 2011). Today, wind power is by far the largest single renewable energy source (other than hydropower), with 47 GW of installed capacity at the end of 2011 (AWEA 2012). The U.S. wind industry installed more than 6.8 GW in 2011—31 percent higher than 2010—and has more than 8.3 GW under construction in 2012 (AWEA 2012). Wind power is expected to continue to expand to meet state renewable electricity standards. Moreover, while the market share of solar energy is relatively small, it is the fastest-growing renewable technology in the United States. In 2011, the nation added a record 1.8 GW of solar PV capacity, a 109 percent increase over 2010 (SEIA 2012).

The prices of wind and solar energy have dropped dramatically in the last two decades and continue to decline. Even without counting federal or state incentives, many wind projects now deliver lower-cost power than new coal-fired power plants. In areas with

Figure 18. States with Renewable Electricity Standards (RES)



State renewable electricity standards require utilities to increase their use of renewable energy gradually over time. Twenty-nine states and the District of Columbia have adopted an RES, with 17 states setting targets of 20 percent or more. An additional eight states have adopted voluntary non-binding renewable energy goals.

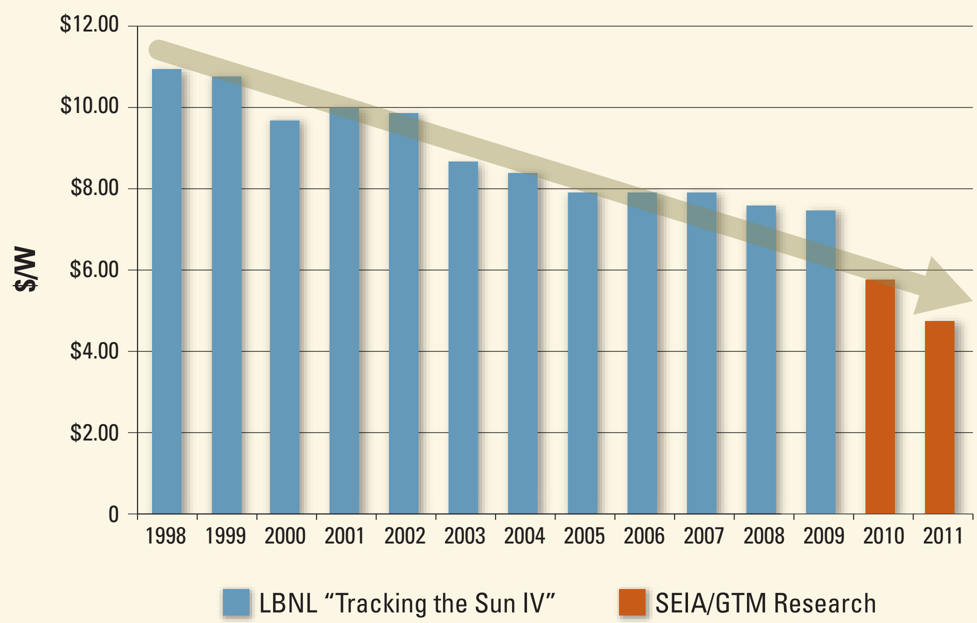
strong wind resources, wind energy can compete even with natural gas plants. Wind power costs are projected to drop 5 to 40 percent lower in the next two years than the previous low in 2002–2003, thanks to technology improvements, recent increases in domestic manufacturing capacity, declining commodity prices, and other factors (Wiser, et al., 2012).

While solar technologies are currently more expensive than natural gas and coal generation in most states, the installed cost of solar PV has fallen 35 percent in the last two years (Figure 19) and panel prices have fallen by more than 50 percent (SEIA 2012). That drop in cost is nearly halfway to achieving the U.S. Department of Energy's Sunshot Initiative goal of reducing the installed cost of PV by 75 percent between 2010 and 2020, thereby making solar energy cost-competitive with other sources of energy, without incentives (DOE 2012).

For energy efficiency, we project that meeting existing state targets would reduce national electricity demand 5.7 percent by 2020 (UCS 2012). A recent EPA analysis reached a similar conclusion, finding that existing state and federal efficiency policies would reduce demand 5.3 percent by 2020 (EPA 2011). The EPA's analysis also showed that, by 2020, this level of efficiency would lead to 25 GW of coal plant retirements, a reduction in generation costs of $6 billion, a reduction in retail electricity prices of 1.6 percent, and emissions reductions of 520 pounds of mercury, 80,000 tons of SO_2, and 110,000 tons of NO_x.

While these gains are appreciable, a number of studies have found that much greater near-term

Figure 19. Solar PV Prices Are Falling Rapidly (Average Installed $/Watt)



The solar power industry is well on its way to achieving the U.S. Department of Energy's Sunshot Initiative goal of reducing the installed cost of solar PV panels 75 percent by 2020. In the last two years alone (red bars), the installed cost of solar PV has fallen 35 percent and panel prices have dropped more than 50 percent.

Source: SEIA 2012.

demand reductions are feasible and cost-effective. A recent McKinsey & Co. report, for instance, found that the United States could reduce annual non-transportation energy consumption 23 percent below projected levels by 2020, using only efficiency measures that paid for themselves and without assuming a price on carbon (Granade et al 2009).

The southeastern states notably lag behind the rest of the nation in adopting energy efficiency and renewable energy policies. However, assessments of their existing efficiency and renewable energy potential make clear that those states have abundant opportunities to develop clean energy sources. For example, Florida has the highest electricity demand of the southeastern states; a 2008 report for the state Public Service Commission found that, with favorable policies, it would be technically feasible for Florida to get as much as 24 percent of its electricity from renewable sources by 2020 (Navigant 2008). Georgia is the second-biggest electricity user in the Southeast and the state with the most ripe-for-retirement coal capacity in the nation; a 2009 Southern Alliance for Clean Energy (SACE) report found that by 2015 Georgia could achieve renewable energy potential equal to approximately 25 percent of its 2006 retail electricity sales (SACE 2009). While the Southeast is more limited in land-based wind potential than other parts of the country, the region has excellent opportunities for developing solar, bioenergy, offshore wind, and small hydroelectric generating capacity.

Moreover, because the Southeast states have not been as proactive about implementing energy efficiency programs as other states, they have significant untapped potential for reducing demand. For example, a 2010 analysis by researchers at Duke University and the Georgia Institute of Technology found that adopting energy efficiency policies in the South would not only cut electricity demand but also would, in 2020, reduce energy bills in the South by $41 billion, create 380,000 new jobs, and increase the size of the region's economy by $1.23 billion. A 2007 ACEEE study found that Florida could reduce its projected future electricity use by 19 percent through energy efficiency programs by 2022 (Elliott et al. 2007).

Expanding renewable energy faces hurdles. In particular, sustaining or accelerating the current rapid growth of wind energy will require significant investments in new transmission lines. The most economical sites for wind development are scattered around the country, often far from the urban areas where electricity demand is concentrated. Modeling studies have concluded that the costs associated with new transmission lines needed to support a longer-term increase in wind generation to 20 percent of U.S. electricity use by 2024 would be relatively modest—ranging from 2 percent to 20 percent of total wholesale power costs (EnerNex 2011). However, these studies also found that the costs of building additional transmission lines would be more than offset by lower overall generation production costs.

The time it takes to plan and build a major transmission line can often be a greater obstacle than cost. Federal and state policies and regulations, such as regional implementation of FERC Order 1000 (see more detail in Chapter 5), will help to speed the progress of needed projects and other changes to the grid necessary to integrate increasing amounts of renewable energy and demand-side technologies.

Expansions of transmission facilities to integrate new wind power are already under way in many regions. The American Wind Energy Association has identified near-term transmission projects that could support more than 44 GW of new wind power capacity, on top of the 47 GW of capacity online at the end of 2011 (AWEA 2012). Texas alone is investing $6.5 billion to build 2,300 miles of new high-voltage transmission by 2013 that would support up to 18.5 GW of wind development (O'Grady 2011). In December 2011, the Midwest Independent System Operator (MISO) approved 17 new "multi-value"

> *Federal and state policies and regulations, such as regional implementation of FERC Order 1000, will help to speed the progress of needed transmission projects and other changes to the grid necessary to integrate increasing amounts of renewable energy.*

transmission lines that will provide greater access to areas with high-quality winds, help utilities meet state renewable electricity standards, and improve overall system reliability. MISO also projects that these new lines could provide up to $49 billion in net economic benefits by reducing overall generation and congestion costs that would more than offset the up-front capital costs (MISO 2011).

Completing the Transition to Clean Energy

Over the long term, the need to reduce CO_2 emissions to avoid the most dangerous impacts of climate change will require greater adoption of zero-carbon energy sources and the complete phaseout of conventional coal plants. Eventually, natural gas will also need to be significantly reduced.

Concern about the effects of climate change has prompted many assessments of the potential to make very deep cuts in the carbon dioxide emissions associated with generating electricity. For example, a 2010 analysis by the Electric Power Research Institute (EPRI) concluded that under a scenario where the United States reduces power sector CO_2 emissions 80 percent by 2050, nearly all conventional coal-fired generators could be retired as soon as 2025, with renewable sources of energy and reduced demand from energy efficiency displacing most of the coal-fired generation in the near term (Specker 2010). New nuclear plants do not begin to make a contribution until after 2020, while new coal plants with carbon capture and storage do not contribute until after 2030.

Over the long term, the need to reduce CO_2 emissions to avoid the most dangerous impacts of climate change will require greater adoption of zero-carbon energy sources and the complete phaseout of conventional coal plants. Eventually, natural gas will also need to be significantly reduced.

The UCS *Climate 2030* blueprint also analyzed a scenario that assumes the United States adopts high standards for energy efficiency and renewable energy that are consistent with those of the leading states, and sets a national target to cut total U.S. carbon emissions 57 percent by 2030 and at least 80 percent by 2050 (Cleetus et al. 2009). With achievable improvements in energy efficiency that would reduce the nation's demand for electricity 35 percent by 2030, the UCS blueprint concluded that renewable energy could reliably supply at least half of U.S. electricity needs by 2030. The blueprint also found that the combination of renewable energy, energy efficiency, and efficient natural gas generation would reduce coal generation and electricity sector CO_2 emissions nearly 85 percent by 2030, while saving consumers billions of dollars on their electricity bills.

A more recent 2012 National Renewable Energy Laboratory (NREL) study found that renewable energy technologies commercially available today could supply 80 percent of total U.S. electricity generation in 2050, while reducing power plant carbon emissions by 80 percent and water use by 50 percent. Under this scenario, U.S. coal generation is projected to decline from 42 percent of total U.S. electricity generation in 2011 to less than 10 percent in 2050, and natural gas generation from 25 percent in 2011 to less than 3 percent in 2050. The study also found that achieving this high level of renewable energy would require "increased electric system flexibility…from a portfolio of supply- and demand-side technologies including flexible conventional generation, grid storage, new transmission, more responsive loads, and changes in power system operations" (NREL 2012).

The prospect of change on that scale may seem daunting. But large steps in that direction are clearly possible, and are already being taken in some states and other countries. For example, in 2010, wind power provided more than 20 percent of the electricity in Iowa and South Dakota and more than 10 percent in Minnesota, North Dakota, and Oregon (AWEA 2012; Wiser and Bolinger 2011). Several European nations have gone further. In 2010, wind supplied 26 percent of Denmark's annual electricity needs and 17 percent of Portugal's, and more than 44 percent of the electricity for three German states (Global Wind Energy Council 2012; Wiser and Bolinger 2011).

What Are the Risks of an Over-Reliance on Natural Gas?

Natural gas has become more abundant and more affordable in the past few years. Natural gas prices have declined dramatically as advances in hydraulic fracturing or "fracking" have significantly increased natural gas supplies from shale and other natural gas deposits. While natural gas is currently an economically attractive option for replacing coal generation, a significant increase in the nation's dependence on natural gas has many economic, environmental, public health, and safety risks. These include:

Supply and price volatility. Although natural gas is abundant today, it could be subject to shortages and price spikes in the future, like the United States experienced in the past decade after the last major natural gas power plant construction boom. Between 2000 and 2008, nearly 260 GW of new natural gas electric generating capacity was added in the United States, resulting in a 28 percent increase (1.5 trillion cubic feet) in natural gas use in the electricity sector, according to data from the EIA. This increase in natural gas use, which was larger than any other sector, contributed to spikes in monthly wholesale natural gas prices of more than $11 per million Btu in 2005 and 2008.

In 2011, the EIA reduced its estimates of shale gas reserves in the United States by more than 40 percent, including significant reductions in reserves from the Marcellus Shale based on updated assessments by the U.S. Geological Survey (EIA 2012e; Coleman et al. 2011). Uncertainties in the size of available supplies combined with potential increases in natural gas demand for electricity, heating, factories, vehicles, and exports could put significant upward pressure on natural gas prices in the future.

Environmental impacts of hydraulic fracturing. "Fracking" involves drilling a well into shale formations deep underground and injecting millions of gallons of water, chemicals, and sand under high pressure to break open fissures in the rocks and release the natural gas. In addition to using millions of gallons of water for each well, this process can have adverse impacts on water quality, the environment, and public health.

A 2011 National Academy of Sciences study found the first systematic evidence of methane contamination of private drinking water at sites above the Marcellus and Utica formations in Pennsylvania and New York where shale gas was being extracted. Based on groundwater analyses of 60 private wells in the region, methane concentrations were found to be 17 times higher on average in areas with active drilling and extraction than in non-active areas (Osborn et al. 2011).

While natural gas is currently an economically attractive option for replacing coal generation, a significant increase in the nation's dependence on natural gas has many economic, environmental, public health, and safety risks.

The use of numerous chemicals is required throughout the shale gas extraction process. From 2005 to 2009, one investigative report found that fracking uses more than 750 chemicals (U.S. House of Representatives 2011). Another study identified 632 chemicals contained in fracking products used in shale gas extraction. Researchers could track only 353 chemicals from that larger list and found that 25 percent of those chemicals cause cancer or other mutations, and about half could severely damage neurological, cardiovascular, endocrine, and immune systems (Colborn et al. 2011).

Each shale gas well typically requires 2 million to 5 million gallons of water for drilling and fracturing. Much of this chemical-infused water can remain underground, with the risk that it could then leak into groundwater supplies (GWPC and ALL 2009). The rest of the water flows back to the surface as wastewater. Fracking wastewater is not only laden with methane and neurotoxins, but also can be radioactive (Osborn et al. 2011). The radioactivity in fracking wastewater has been found to be hundreds to thousands of times above EPA standards. If discharged into a sewer system, most wastewater treatment plants lack the equipment to remove the contaminants adequately before discharging the effluent into rivers, lakes, and streams.

New state and federal laws and regulations are needed to reduce the environmental and public health impacts of fracking. Such laws and regulation would likely not only reduce the amount of natural gas that can be safely extracted, but also raise its cost.

Global warming emissions. Simply expanding the use of natural gas as an alternative to coal is not a solution to climate change. Although considered to be cleaner burning than coal, natural gas is still a fossil fuel that emits carbon dioxide when combusted. While smokestack CO_2 emissions from a new efficient natural gas plant are about 60 percent less than an average existing coal plant, one study found that a large global shift to natural gas would still put us on an emissions trajectory (based solely on smokestack emissions—see below) to a temperature increase of as much as 6°F (IEA 2011), a level of warming associated with catastrophic environmental and economic consequences.

In addition, recent scientific research indicates that the life-cycle global warming emissions from natural gas use are far greater than what occurs when simply burning the natural gas to produce electricity. The drilling and extraction of the natural gas from wells, and its transportation in pipelines, results in the leakage of methane, a far more potent global warming gas than CO_2. While more research is needed, some recent studies and field measurements have shown high methane leakage rates that would result in total fuel-cycle global warming emissions for natural gas that are at least similar to or even higher than emissions from coal (Howarth et al. 2012; Petron et al. 2012; Howarth et al. 2011).

Technologies are available to reduce much of the methane leakage associated with drilling and other parts of the production process (Harvey et al. 2012; IEA 2012). But deploying such technology would be costly, as it would require significantly altering current business practices as well as replacing or upgrading thousands of miles of existing pipelines. This would be an incredibly expensive investment for what could at best be described as a temporary energy solution if ultimately we are to move to a truly low-carbon electricity system.

Crowding out renewable energy. With historically low natural gas prices and no long-term national policy support for renewable energy, there is a real danger that natural gas could crowd renewable energy out of the market. Scaling up renewable energy sources now is critical to further reducing their costs, encouraging innovation, and transitioning to a low-carbon energy system. From a climate perspective, the window for this transition is very small and growing smaller every year we delay. By diversifying the electricity mix, renewable sources of energy can also provide an important hedge against future natural gas price increases.

CHAPTER 5
Modernizing the Electric System

Achieving a smooth transition to a cleaner, more sustainable, and affordable electricity system will require utility regulators, power grid operators, utility companies, and power producers to make appropriate resource planning and policy choices. Investments made in new transmission lines and new power generators—whether fossil-fueled or renewable—create long-lived assets that remain part of the nation's energy portfolio for decades. As such, the choices we make today will profoundly affect how quickly, affordably, and reliably we can shift to cleaner energy sources and reduce the emissions that are causing climate change. To accelerate this transition, we offer the following recommendations.

Enact Strong EPA Power Plant Standards

The EPA is taking important steps to reduce the enormous health and environmental costs that coal-fired power plants impose on the American public. Standards have already been finalized to limit SO_2, NO_x, and particulate pollution as well as emissions of mercury and other toxic substances. The agency has proposed standards to limit carbon dioxide emissions from new power plants, as well as measures to limit the harm coal units cause to water quality and aquatic ecosystems (Cleetus 2012; see Appendix B). Such standards have been years or even decades in the making; they provide a tremendous opportunity to clean up and modernize our electric system.

The EPA can take several steps to ensure that these standards facilitate an orderly transition to a clean, affordable, and reliable electric system:

1. Building on the recently adopted rules for SO_2, NO_x, mercury, and other pollutants, the EPA should finalize and implement for both new and existing power plants additional strong standards for carbon dioxide emissions—consistent with the latest climate science—and for coal ash disposal, cooling-water intake structures, and plant wastewater treatment. Such measures will provide significant economic benefit through reduced health and environmental costs. In addition, they will level the playing field for cleaner and less resource-intensive generation sources and reduce investment uncertainty.

To level the playing field for cleaner generation sources, the EPA should finalize standards for carbon dioxide emissions, coal ash disposal, and wastewater and cooling-water intake structures.

2. As it enforces pollution standards, the EPA should give states the flexibility to use renewable energy and energy efficiency measures as eligible compliance strategies instead of relying solely on strategies to directly control emissions from conventional power plants. Such a flexible approach, designed well, will create incentives to invest in additional no-carbon alternative resources alongside the retrofitting of existing coal plants.

3. The EPA has already committed to using all existing flexibilities in the Clean Air Act to ensure that power plant operators have enough time to comply with the new air quality standards, and to allow for case-by-case compliance extensions where necessary to ensure adequate energy supplies and power grid reliability. The agency should follow through on this commitment without allowing for unnecessary delays or blanket exemptions that would undermine the public health imperative that prompted these standards.

4. The EPA should solicit information from utilities, regional transmission organizations, and state environmental and public utility regulators as appropriate concerning the scheduling of coal plant retirements and needed retrofit work. Early

availability of this information will help identify and address the isolated cases where more time or additional generation or transmission resources may be needed to maintain the reliability of the electric system.

5. The EPA should follow through with its announced intention to coordinate the implementation of the new standards and related retirements with electric reliability and planning authorities, including FERC, NERC, state public utility commissions, and regional transmission organizations.
6. Although FERC cannot enforce EPA rules, the commission has ultimate responsibility for power system reliability, effective transmission planning, and the assurance of just and reasonable rates. Thus, FERC must ensure that the aspects of retiring generating units and retrofits planning within its jurisdiction reliably facilitate the implementation of recent and pending EPA standards. With sufficient direction and oversight, FERC can significantly reduce the number of cases in which coal generators request exemptions from compliance with EPA rules or are granted reliability-related supplementary payments that delay the retiring of coal generators.

Adopt Strong State and Federal Clean Energy Policies

Several states have already adopted clean energy and climate policies that will help drive the replacement of existing coal plants with affordable clean energy resources, and will thus avoid costly retrofits. Similarly comprehensive policies are needed in other states and at the national level to overcome market barriers to developing clean energy and more fully realizing the economic and environmental benefits of transitioning away from coal. While experience in wind and solar energy over the last 30 years shows powerful evidence of steep, rapid cost declines, the next 5 to 10 years will be a critical period in the development of a robust renewable energy sector. Policy support is essential to ensure continued growth and the cost reductions that come from learning, innovation, and economies of scale.

The following policies build on the most effective approaches pursued by pioneering states, utilities, and the federal government:

1. **Extend tax and other financial incentives for renewable energy and energy efficiency.** Federal tax credits have been a key driver for developing renewable energy and new manufacturing jobs in the United States. For example, over the past decade, U.S. manufacturing of wind turbine components has grown to more than 400 facilities in 43 states now producing more than 60 percent of the components installed in the nation (Wiser and Bolinger 2011). Unfortunately, delays and short-term extensions of the credits have produced a boom-and-bust cycle that raises costs and creates needless uncertainty for the financing and construction of renewable energy projects. Congress should extend by at least four years federal incentives for renewable energy and energy efficiency, including the federal production tax credit for wind power and other renewable sources. Congress should also reduce incentives for fossil fuels and nuclear power, because those mature technologies have already received enormous subsidies for decades that continue to give such unsustainable resources an unfair market advantage.

Congress should extend by at least four years the federal production tax credit for wind power.

2. **Adopt strong renewable electricity standards.** More than 20 comprehensive studies over the past decade have found that renewable electricity standards—that is, standards requiring that a certain percentage of electricity must be generated from clean, renewable sources of energy—are an effective and affordable way to reduce energy generated from coal and natural gas, while reducing their associated emissions, creating jobs, and helping to stabilize natural gas and electricity prices (UCS 2009; Nogee et al. 2007). Congress and state governments should enact strong policies that require electric utilities to procure at least 25 percent of their power from clean renewable sources by 2025. To date, 29 states and the District of Columbia have adopted standards, with 17 states having renewable energy targets of 20 percent or more by 2025. A strong national RES would cement this progress and ensure that it happens in every state in the nation.

3. **Enact strong energy efficiency standards.** Congress and state governments should enact strong standards requiring electricity and natural gas providers to meet annual targets for reducing energy use in homes, businesses, and factories. Twenty-four states have adopted such standards or similar long-term energy savings targets for individual utilities; indeed, at least eight states have adopted targets to reduce electricity use by 2 percent or more per year (ACEEE 2011). The federal government should also continue its successful strategy of raising efficiency standards for home appliances and other equipment as new products become available. Further, states should continue to increase the stringency of energy efficiency codes for buildings over time to ensure that builders are deploying the most cost-effective insulation and energy-saving technologies and best practices.
4. **Advance the deployment of combined heat and power (CHP) systems.** CHP is a well-established but underused technology that entails generating electricity and heat from a single source (typically a natural gas generator), dramatically increasing energy efficiency. By taking advantage of the waste heat from producing electricity, CHP systems can achieve efficiencies of up to 80 percent, compared with about 33 percent for an average coal power plant and 40 to 50 percent for a new natural gas plant. The nation can encourage the deployment of CHP systems by establishing federal standards for permitting such systems, connecting them to the local power grid, and establishing market-based payment mechanisms for the power they produce. Greater funding for federal and state programs that spur the use of CHP through education, coordination, and direct project support is also needed.
5. **Increase research and development (R&D) funding for clean energy technologies.** Public funding for energy efficiency, renewable energy, advanced smart-grid technologies, and energy storage R&D has languished over the last few decades. Greater R&D support will help lower costs, improve efficiencies, and spur widespread adoption of these technologies. Private investors play an essential role in developing and commercializing clean energy technologies: U.S.-based venture capital investments in clean technologies reached $6.6 billion in 2011, a 30 percent increase over 2010 (Pernick et al. 2012). But public funding is a critical complement to private capital. Programs such as the Department of Energy's Advanced Research Projects Agency—Energy (ARPA-E), for instance, invest in transformational energy research that the private sector is unlikely to fund.

State regulators should not allow a utility to recover the cost of pollution controls from ratepayers if a coal plant can instead be retired and replaced with more affordable clean energy alternatives.

6. **Price carbon emissions.** A core element of our nation's response to climate change should be a federal policy that delivers deep cuts in carbon dioxide emissions swiftly and efficiently, and charges polluters for their remaining emissions. Such a policy should create a clear market signal that rewards cuts in heat-trapping CO_2 emissions and drives private investments in clean energy. It should also include critical features such as a mechanism for setting and adjusting emissions targets to match the latest science, incentives to support investments in renewable energy and efficiency, and consumer protections (such as energy rebates for low-income families) that do not diminish the overall effectiveness of the policy.[25]
7. **Encourage greater investment in advanced transmission and smart-grid technologies.** Modernizing the U.S. electric grid and the rules that govern it is essential if the nation is to transition effectively to a cleaner, more modern and efficient electric system. Policy changes, more research and development, and increased investments in new transmission and distribution infrastructure are needed if we are to fully realize the potential of a modern electric system with the ability to integrate and effectively use emerging technologies. For example, high-voltage direct current transmission lines can be a cost-effective investment to transport low-cost renewable energy efficiently over long distances, enabling significant development of new clean

[25] For more information on the policy design of a carbon cap to help meet climate goals, see Cleetus et al. 2009.

energy resources. Other examples include new smart-grid applications that can improve the performance of the electric grid at both the transmission and local distribution levels, demand-response technologies that reduce power during peak periods, and stepped-up integration of clean energy sources such as wind and solar.[26]

Improve Resource Planning by Regional Grid Operators and Utilities

Regional transmission organizations (RTOs) and independent system operators (ISOs) operate large sections of the nation's power grid; the balance is operated by individual utilities. As more coal plants retire, all these entities must continue to ensure adequate and reliable energy supplies. The utility industry has typically taken a narrow view of the options available to them to match power supply with demand, a view oriented historically toward building new fossil-fueled generation and new transmission lines. Such an approach has often led the industry to underestimate the role that clean energy alternatives such as renewable energy, reducing demand through energy efficiency, and other consumer-based (demand-side) resources can offer to meet future energy needs. To encourage the industry to do a better job accounting for clean energy resources when planning their systems, FERC Order No. 1000 requires RTOs, ISOs, system planning authorities, and individual transmission utilities to consider fully how existing state and federal policies (such as environmental, efficiency, and renewable energy standards) will shape the supply and demand for power and related transmission and distribution infrastructure in the future. There are additional steps that FERC, states, and individual utilities can take to ensure that the system can accommodate an increasing number of retiring coal generators while maintaining the reliability of the electric system:

1. **FERC must ensure full compliance with Order No. 1000.** The commission must ensure that utilities and transmission planning entities (such as RTOs) modify their annual planning processes and develop plans for their regions that reflect minimum resource requirements. Such modifications should include: (a) developing procedures for determining power grid needs driven by the full range of clean energy policies being considered at the state and federal levels; such policies include expanded state-level renewable energy and energy efficiency standards, and greater use of industrial efficiency technologies such as CHP systems, smart-grid technologies, and other distributed clean energy resources that can improve system reliability; (b) provide transparency and opportunity for timely, meaningful stakeholder input into regional planning processes; (c) develop effective procedures for RTO coordination between neighboring regions in regional planning processes; and (d) require various regional cost-allocation approaches for designated projects in regional plans.
2. **States should require regulated utilities to conduct comprehensive resource planning.** While RTOs and ISOs are responsible for oversight of the power grid in many areas of the country, utility regulators at the state level retain significant authority to influence decisions about power generation and related investments. This is particularly true in states where traditionally structured utilities—which own their own transmission facilities and power plants—must seek approval from public utility commissions (PUCs) before they can invest in new power plants or retrofit existing ones, or at least before such costs can be passed through to customers via their electricity bills.

State PUCs should develop and implement comprehensive resource planning processes that require all utilities under their jurisdiction to evaluate fully and fairly the economics of all available alternatives for meeting projected electricity needs in their state, including demand-side resources and available clean energy technologies. Such planning processes should explicitly recognize that the nation's aging fleet of coal plants will soon need to be either retrofitted with pollution control devices or retired, and factor in the full range of costs and benefits when comparing those alternatives—including the future costs of addressing carbon dioxide emissions.

Regulated utilities may have an incentive to favor retrofitting existing coal plants because any capital

[26] For more information on policies, investments, and technological changes needed to enhance transmission infrastructure and move toward a smart grid, see Joskow 2011 and MIT 2011.

Shifting our reliance on coal to a new reliance on natural gas would be a missed opportunity to transition to truly low- or no-carbon resources that have less impact on the environment and public health.

improvements that regulators approve are given a guaranteed rate of return and guaranteed cost recovery from ratepayers. PUCs should allow a utility to recover the cost of pollution controls from ratepayers only if the utility has demonstrated, using comprehensive long-term planning, that the public interest could not be better served by retiring the coal plant and replacing it with more affordable clean energy alternatives such as wind power and reduced demand from energy efficiency. In evaluating the effects of retiring a coal-fired generator, utilities should study and disclose the environmental benefits of emissions reductions associated with closing the plant as well as options for addressing any localized power reliability concerns, such as building transmission lines. This planning should be transparent about all cost assumptions, to allow meaningful review both by the public and by regulators. Regulators in states that lack planning requirements should require utilities to prepare such plans.

In states that have deregulated their utility industry, power generation and delivery of that power to customers have been separated. In those states, power plant owners sell the electricity they generate in energy markets run by ISOs and RTOs and to utilities through competitive auctions. In deregulated states, public utility commissions have limited authority over independent power producers (IPPs) and can neither approve nor reject a power plant owner's decision to invest in expensive pollution controls. Decisions to retrofit or retire coal plants largely depend on whether IPPs can recover the costs (plus a return) in the competitive generation market and whether they can raise the necessary capital from banks, corporate balance sheets, investors, and other sources to finance the retrofits. Raising such capital is growing increasingly difficult because of the poor economics of aging coal generators. For example, Edison Mission Energy announced recently that it was unable to raise the financing necessary for pollution control upgrades at its Homer City plant in Indiana County, PA, a 43-year-old facility that is considered one of the dirtiest coal-fired plants in the nation (Edison International 2012).

Conclusions

The nation's fleet of coal plants is becoming less and less economic to operate. With abundant cleaner energy resources beginning to realize their potential to meet America's growing energy needs, burning coal to produce electricity is rapidly becoming outdated. Many older, dirtier, and underutilized coal units simply cannot compete economically with natural gas or wind power. Combining these and other cleaner resources with upgrades to the power grid (i.e., investments in new transmission lines) and investments in energy-saving technologies can more than replace the generation from the 353 coal-fired generators (59 GW) we identified as ripe for retirement. Long-overdue clean air standards will make it even harder to justify continuing to operate or invest in heavily polluting coal plants, particularly since those plants are among the largest sources of carbon dioxide pollution in the United States.

To ensure a smooth and accelerated transition toward a cleaner energy system, federal and state governments should adopt and implement strong pollution standards that require coal plants to finally clean up their act. Regional power grid managers should fully and fairly evaluate the availability of clean energy resources as well as investments in transmission facilities when determining if coal plants are needed to maintain system reliability. Likewise, public utility commissions should compel the utility companies they regulate to conduct system-wide planning in order to assess whether cleaner alternatives can more affordably meet customers' energy needs instead of allowing power plant owners to charge ratepayers hundreds of millions of dollar to extend the life of an old, dirty coal plant. In deregulated states, merchant power producers, who may not be able to recoup an investment in expensive pollution controls in competitive wholesale power markets, are already finding that the bankers who finance investments to retrofit old coal plants are increasingly skeptical about whether such capital investments are financially prudent. Finally, the federal government must adopt policies and fund research and development to advance the cleanest technologies at the lowest possible cost. The key is to align short-term market-driven incentives with longer-term goals for modernizing and decarbonizing our electric system.

Several midwestern states, such as Illinois, Michigan, and Ohio (home to many of the nation's obsolete coal plants), have already adopted policies to promote clean energy development. Yet these states can take *greater* advantage of wind power, solar energy, and energy efficiency to accelerate their transition to a clean energy economy and further hasten the closure of coal plants. States in the Southeast, however, have done little so far to tap the clean energy resources that could drive new investment, create jobs, and improve public health. Those states have the greatest opportunity to shutter coal plants, partly because utilities in these states have taken little if any action to modernize their coal fleets.

Making the transition to a modern and sustainable energy system involves more than just adding new clean power to the grid or regulating pollution from the existing coal fleet; it also requires getting the dirtiest old power sources off the grid. Thoughtful planning about how to retire coal plants will help grid operators and state regulators maximize the economic returns and the human health and environmental benefits of a cleaner energy future, while maintaining reliable and affordable power for American families and businesses.

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APPENDIX A
Methodology

Coal-fired Generator Database

We compiled a database of all utility coal-fired generators in the United States as of 2009—the last year for which data are available—using data from the Energy Information Administration (EIA) of the U.S. Department of Energy. We filtered out the 288 coal generators that have already been scheduled for retirement or conversion to natural gas (as of May 31, 2012) using information from SNL Financial, the EIA, the Sierra Club, Sourcewatch, and various news accounts from industry trade publications. Generators listed as retired before 2008, mothballed, terminated, or out of service were also removed. In addition, we filtered out all coal generation used for industrial, educational, or other non-utility purposes. As a result, our working data set consisted of 1,169 operational coal-fired electric-utility generators with a total installed capacity of 334.7 gigawatts (GW) in 2009.

Core Analysis Methodology

Our core economic analysis consisted of three key steps. First, we identified the base running costs of currently operating coal generators. Next, we determined the absence or presence of four types of the most essential pollution controls for each coal generator, and then we added to the base running costs those costs of installing each control technology to any generator that is missing it. Lastly, we determined the relative economic competitiveness of coal generators (both individually and collectively) with and without these pollution control technologies compared with average existing and new natural gas combined-cycle (NGCC) facilities. Our three-step methodology is similar to the approach used by Synapse Energy Economics in an analysis of the economic merit of coal-fired power plants in the West (Fisher and Biewald 2011).

Any coal generator that was more expensive to operate than a NGCC power plant would meet our threshold of being ripe for retirement. We established a range for the number of ripe-for-retirement coal generators out of the total of 1,169. Our low estimate of 153 generators was determined by comparing their operating costs with the average cost of a new NGCC unit. Our high estimate of 353 ripe-for-retirement coal generators is based on a comparison with the average cost of an existing NGCC plant. Existing NGCC units whose capital costs have been largely paid off operate at a lower cost per megawatt-hour of generation than do new NGCC units where new capital investment is required.

Coal Generator Operating Costs

To estimate the total operating costs (in dollars per megawatt-hour) of each coal generator in the data set, we added the cost of fuel to fixed and variable operations and maintenance (O&M) costs. Fuel costs were determined by using heat input at the generator level, and heat content and delivered cost of coal, as reported to the EIA at the plant level (EIA 2009). When these data were not available, we used national averages derived from the same EIA data. Total fuel cost was then divided by the generator's net generation to arrive at a cost of fuel in dollars per megawatt-hour. Out of the full dataset, 206 coal generators did not report a heat input, but they did report net generation. For these generators, we could not estimate a fuel cost despite the fact that they were burning fuel to generate electricity. We therefore assumed a fuel cost of zero for these generators, which resulted in a conservatively low estimate of their total operating cost.

To estimate fixed and variable O&M costs, we used the same methodology developed by the North American Electric Reliability Corporation (NERC). Table A-1 (p. 74) shows NERC's assumptions for such costs, which decline as the size of the coal generator increases (NERC 2010).

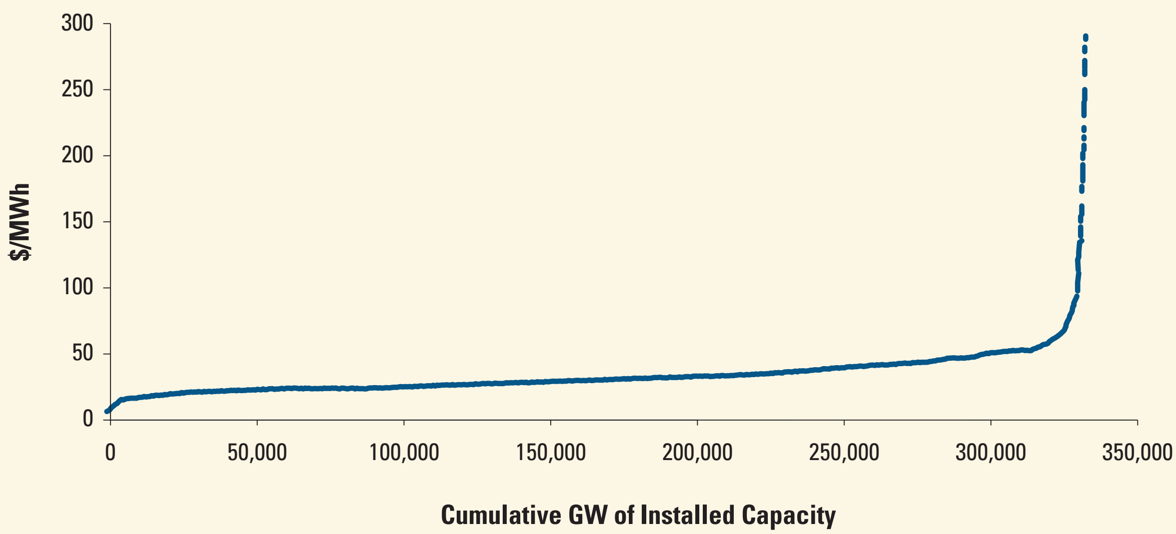
Table A-1. Fixed and Variable Operations and Maintenance Costs, by Capacity

Installed Capacity (MW)	Fixed Operations and Maintenance ($/kW-yr)*	Variable Operations and Maintenance ($/MWh)
< 100	30	5
>100	21	4
>300	18	4

* 1$/MWh = $/kW-yr/(8.76 multiplied by capacity factor)
Source: NERC 2010, Appendix I.

Figure A-1 shows the results of estimating the current running costs of each coal generator in the 2009 operational fleet for which there was sufficient data, equal to 334.7 GW. The majority of the coal fleet has a base running cost under $50/MWh, and about half the fleet has running costs that are just over $25/MWh. About 35 GW of coal generators have running costs above $50/MWh; indeed, there is a very steep increase in costs to as high as $289/MWh for the most expensive 10 GW of installed capacity. Much of the coal-fired generation that costs more than $50/MWh is produced by smaller, older, and less efficient generators that have higher O&M costs.

Figure A-1. Supply Curve of Coal Generator Running Costs



This figure shows the 334.7 GW of installed capacity and the levelized cost of electricity as a function of fuel, fixed O&M costs, and variable O&M costs. Running costs ranged from $6.50/MWh to $289/MWh, depending largely on capacity factor and efficiency. Generators with operating costs greater than $50/MWh are typically the smallest, oldest, and least efficient among the operational coal fleet.

The Cost of Installing Pollution Controls

After estimating base running costs, we then identified which units are currently lacking key pollution control technologies to reduce emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter, and mercury, and calculated the costs of installing such controls on each generator. We used the National Electric Energy Data System (NEEDS) database of the Environmental Protection Agency (EPA) to identify the absence or presence of a given pollution control technology for each coal generator (EPA 2010b). The EPA NEEDS database was then linked to individual coal generator operating cost data based on plant code and unit-level identifiers so that the cost of adding a given pollution control technology, if not already present, could be estimated.

Our analysis assumed that the following pollution controls would be installed (if not already present) at each coal generator: a wet scrubber to control SO_2, selective catalytic reduction (SCR) for NO_x, a baghouse for particulate matter, and activated carbon injection (ACI) for mercury. The presence of a dry scrubber (for SO_2) or selective non-catalytic reduction (for NO_x) was determined to be adequate pollution control for our analysis.

We estimated the total costs (including capital costs and fixed and variable O&M costs) of adding wet scrubbers and SCR using data from the EPA Integrated Planning Model (Sargent & Lundy 2010a; Sargent & Lundy 2010b). For determining emissions, we assumed a constant NO_x removal rate of 87.5 percent; we varied the SO_2 emissions rate based on generator reporting, and used national averages to adjust for the sulfur content of bituminous, subbituminous, or lignite-based coal fuels. For labor and other component costs, such as limestone, waste disposal, auxiliary power, and water, we used the EPA's default values. We also included the variable costs required for additional auxiliary power needs. When emissions data or capacity factor values were not available, we developed a regression analysis that log-transformed the data to estimate the cost of adding pollution controls. Results of our regressions varied for each pollutant, but overall showed explanation of variation with an r-squared of 0.75 for both SO_2 and NO_x controls.

The methodology and assumptions used to determine the costs of adding baghouses and activated carbon injection were based on an analysis prepared for the Eastern Interconnection Planning Cooperative (CRA International 2010; Cichanowicz 2006).

In addition, we also adjusted pollution control cost estimates such that if multiple units went into a single flue, SO_2, particulate matter, and mercury pollution controls were calculated for a single exhaust rather than for each unit, thereby reducing the cost of adding pollution controls. This adjustment was not made for NO_x pollution controls because in order to function properly, the catalyst in SCR technology must be installed at the boiler and injected at a high temperature before the gas exits the flue.

Some of the coal generators in the operational fleet installed pollution control technologies after 2009. In these cases, we estimated the costs of installation, and then added those costs to our base operating cost estimates for 2009. This allowed us to include generators that had pollution controls installed in 2010 or later but also to ensure that the costs of adding those technologies were included in our economic comparisons with cleaner alternatives. We did not analyze any potential de-rating or small incremental energy losses from powering installed pollution controls.

Comparing Coal with Cleaner Energy Sources

After estimating the base operating costs and the cost of adding pollution controls for those coal generators lacking scrubbers, post-combustion NO_x controls, baghouses, or ACI, our analysis then compared the estimated total cost to operate each coal generator at its 2009 capacity factor against the cost of producing power from three competitive energy resources: existing NGCC plants, new NGCC plants, and new wind power facilities.

The cost and performance assumptions for the alternative technologies are listed in Table A-2, p. 76. The assumptions were largely taken from the EIA's *Annual Energy Outlook* (EIA 2012c; EIA 2011a), with the exception of heat rate for existing natural gas generation, which was drawn from an analysis by the

Table A-2. Fixed and Variable Operations and Maintenance Costs, by Capacity

	Existing NGCC	New NGCC	Wind
Overnight capital cost ($/kW)	-	1,000	2,000
Fixed charge rate	-	12%	9%
Fixed O&M ($/kW-yr)	14.44	14.44	27.73
Variable O&M (cents/kWh)	0.31	0.31	0
Heat rate (Btu/kWh)	7,700	6,430	0
Average natural gas price (AEO 2012) ($/MMBtu)	4.88	4.88	0
Fuel escalation rate (20 yr) (%)	2.5	2.5	0
Fuel levelizing factors	1.25	1.25	0
Fuel cost (avg. price) (cents/kWh)	4.7	3.9	0
Electricity cost (cents/kWh)[a]	5.2	6.0	7.2
Alternative Scenarios			
Wind w/PTC (cents/kWh)[b]	-	-	5.2
CO_2 price (cents/kWh)	0.69	0.57	0
Electricity cost - low[c] natural gas price (cents/kWh)	4.0	5.0	-
Electricity cost - high[c] natural gas price (cents/kWh)	6.4	7.0	-

[a] Figures based on AEO 2012.
[b] Assumes 85 percent capacity factor for gas and 35 percent capacity factor for wind.
[c] EIA base forecast multiplied by 0.75 or 1.25 to create a low and high gas price respectively.

American Clean Skies Foundation, a natural gas industry trade organization (Swisher 2011).

All wind economic assumptions were also based on EIA data (EIA 2011a). In addition, we assumed an average capacity factor of 35 percent based on a review of recently installed wind turbines by Lawrence Berkeley National Laboratory (LBNL) (Wiser and Bolinger 2011). The LBNL report showed capacity factors ranging from 20 percent to 46 percent for 2009 wind projects, and suggested that reduced curtailment, project siting, larger rotors, greater hub heights, and advances in low-wind-speed turbines could increase the capacity factor in future projects.

Alternative Scenarios

Our analysis presents several alternative scenarios to examine the effect of key variables that could each influence the relative economic competitiveness of the operational coal fleet, including natural gas prices, tax incentives for the deployment of wind power, and a price on carbon dioxide. Table A-2 lists some of the cost assumptions used in our alternative scenarios.

Natural gas prices. Our core analysis assumed a national 20-year levelized natural gas price of $4.88/MMBtu ($4.88 per million British thermal units) for both existing and new NGCC units, based on the EIA's reference case projections for the electricity sector from its *Annual Energy Outlook 2012* (EIA 2012c). In our alternative scenarios, we also examined the effect on the economics of operating coal generators, using forecasts for a low and a high natural gas price for both new and existing natural gas facilities to account for uncertainty in fuel supply and demand. The low natural gas price scenario assumed a 25 percent decrease in the EIA's reference case projections (to $3.66/MMBtu), while the high natural gas price scenario represented a 25 percent increase in the EIA projections (to $6.10/MMBtu).

A price on carbon. In addition to assessing the effect of variability on the price of natural gas, we analyzed the effect of putting a price on carbon as a generic proxy for a constraint on carbon emissions. We assumed a carbon price of $15 per ton, which is consistent with more conservative, low-cost price forecasts from several government, industry, and expert analyses (Johnston et al. 2011).* A carbon price raises the operating costs of both coal generators and natural-gas-fired plants. However, based on smoke-stack CO_2 emissions, which we assumed to be 119 lb of CO_2/MMBtu (NETL 2007), new NGCC plants typically produce approximately half the CO_2 emissions per megawatt-hour of power generated by new coal plants, and 36 percent of the average CO_2 emissions for the existing U.S. coal fleet. As a result, placing a price on carbon has a greater cost impact on electricity generated from coal than from natural gas. Conversely, renewable energy sources such as wind and solar that emit zero carbon dioxide would realize an even bigger cost advantage.

Wind production tax credit (PTC). The federal PTC provides a 2.2-cent-per-kilowatt-hour benefit for the first 10 years of a wind power facility's operation. However, we assume the PTC has a 20-year levelized value of two cents per kilowatt-hour (Wiser and Bolinger 2011). The PTC reduces the cost of generating electricity from wind in our analysis from 7.2 to 5.2 cents per kilowatt-hour (based on a 35 percent capacity factor), which is competitive with the cost of power from existing natural gas plants (Table A-2). The PTC is currently set to expire at the end of 2012. Our core analysis compared the economics of coal generators with the cost of a new wind facility at an average wind resource location (with a 35 percent capacity factor) without the PTC (i.e., assuming the PTC is allowed to expire). The PTC alternative scenario assumes that the PTC will be renewed.

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* Our carbon price assumption is based on the low-cost case from a 2011 meta-analysis by Synapse Energy Economics, which reviewed more than 75 different scenarios from recent modeling analyses of various climate policies (Johnson et al. 2011). It is also consistent with what the Energy Information Administration assumes in its modeling and long-term energy projections for the United States when evaluating investments in coal plants and other carbon-intensive technologies, and with what many utilities and regulators use in resource planning (EIA 2010).

APPENDIX B
EPA Pollution Standards for Power Plants

The Environmental Protection Agency (EPA) is required under the Clean Air Act to develop and enforce standards for harmful pollutants such as sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter, mercury and other toxic pollutants, and carbon dioxide (CO_2). In addition, the agency is also in the process of finalizing standards for toxic ash residuals from coal combustion, and for cooling-water intake structures at power plants. Although many of the pollution controls we analyzed in this report will reduce air pollutants that the EPA is regulating, it is important to note that we did not model the actual EPA standards. The EPA standards contain compliance flexibilities that may not always require the installation of a specific pollution control technology.

This appendix summarizes some recent and upcoming EPA standards aimed at reducing air and water pollution from coal-fired power plants.

- **The Cross-State Air Pollution Rule** (CSAPR) will reduce NO_x and SO_2 emissions, which contribute to ozone pollution, fine particle pollution, and acid rain. Emissions of NO_x and SO_2 are often carried far from their source by prevailing winds and can cause pollution in other states. The CSAPR requires a total of 28 eastern states to reduce their annual SO_2 emissions as well as their NO_x emissions annually and/or during the ozone season (basically the summer). The rule sets state budgets for those pollutants and allows trading within and among the states (subject to some constraints) to meet overall required reductions in emissions. By 2014, combined with other final state and EPA actions, the CSAPR will reduce power plant SO_2 emissions by 73 percent and NO_x emissions by 54 percent from 2005 levels in the regulated region. The CSAPR was finalized on July 6, 2011, and was originally meant to go into force in January 2012. As this report went to print, the U.S. Court of Appeals for the District of Columbia Circuit issued a ruling vacating the CSAPR. The ruling will likely be challenged. Thus the timeline for a new rule is uncertain.
- **The Mercury and Air Toxics Standard** (MATS) will reduce emissions of mercury and other toxic pollutants (such as arsenic, chromium, and nickel) and acid gases (including hydrochloric acid and hydrofluoric acid) emitted by coal- and oil-fired generators. Even in small amounts, heavy metals and acid gases are linked to health problems such as cancer, heart disease, neurological damage, birth defects, asthma attacks, and premature death. MATS was finalized in December 2011 and became effective on April 16, 2012. The rule sets technology-based emissions limitation standards for mercury and other toxic air pollutants, reflecting levels achieved by the best-performing sources currently in operation. The rule provides for a three-year compliance period (to 2015), with the possibility of a one-year extension (to 2016) that would be made available in a broad range of situations by state permitting authorities. In addition, the EPA can provide for a further one-year extension (to 2017), if needed, via an administrative order. For more information see *http://www.epa.gov/mats/*.
- **Carbon pollution standards for power plants** will reduce emissions of CO_2 from fossil-fired power plants. On March 27, 2012, the EPA proposed an output-based performance standard for new plants that would limit their emissions to 1,000 pounds of carbon dioxide per megawatt-hour of electricity (lb CO_2/MWh). The agency is also expected to issue guidelines for a carbon standard for existing fossil-fired power plants, as required under the Clean Air Act. For more information see *http://epa.gov/carbonpollutionstandard/actions.html.*
- **A proposed rule for coal combustion residuals** (or coal ash) from coal-fired power plants was released by the EPA on June 21, 2010. Coal ash is filled with toxic pollutants that can contaminate the soil and water near disposal sites. The EPA's proposed rule

contained two options to reduce environmental and health hazards by regulating coal ash under the Resource Conservation and Recovery Act (RCRA). A final rule has not yet been issued. For more information see *http://www.epa.gov/osw/nonhaz/industrial/special/fossil/ccr-rule/index.htm.*

- **The Cooling Water Intake Structure Rule** will set Clean Water Act standards that reduce injuries and deaths to fish and other aquatic species caused by water-use practices related to cooling systems in power plants. A proposed rule (issued under the CWA §316(b)) was published on April 20, 2011. The proposed rule limits the amount of fish that can be killed, calls for site-specific studies to reduce such impacts, and requires that new plants install technology that is equivalent to closed-cycle cooling (which continually recycles and cools water to reduce fresh withdrawals from the water body). A final rule has not yet been issued. For more information see *http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/index.cfm.*

APPENDIX C
State Rankings Summary Tables

Table C-1. Summary of 353 Ripe-for-Retirement Coal Generators, by State (High Estimate)

Rank	State	Capacity (MW)	No. of Coal Generators	Net Generation (million MWh)	Avg. Online Year[a]	Avg. Capacity Factor[a]	Avoided CO_2 Emissions (million tons)[b]
1	Georgia	7,411	22	34.7	1969	58%	20.5 – 36.4
2	Alabama	6,534	24	23.4	1963	45%	15.1 – 25.8
3	Tennessee	3,860	22	9.6	1955	33%	6.4 – 10.8
4	Florida	3,815	11	15.6	1978	50%	10.9 – 18.0
5	Michigan	3,648	39	16.0	1961	52%	12.0 – 19.3
6	South Carolina	2,942	11	11.2	1970	46%	6.2 – 11.4
7	Wisconsin	2,450	18	10.1	1962	47%	7.2 – 11.9
8	Indiana	2,431	16	7.3	1966	39%	6.5 – 9.8
9	Mississippi	2,406	8	9.7	1976	51%	7.2 – 11.7
10	Virginia	2,201	20	7.3	1971	42%	5.2 – 8.6
11	Ohio	2,198	16	5.5	1964	31%	3.4 – 5.9
12	North Carolina	2,113	13	7.4	1968	40%	4.6 – 7.9
13	Maryland	2,081	9	8.9	1966	53%	5.5 – 9.6
14	New Jersey	1,897	6	4.3	1969	28%	3.5 – 5.4
15	New York	1,502	12	6.1	1962	51%	4.2 – 7.0
16	West Virginia	1,465	3	6.0	1975	49%	4.7 – 7.4
17	Kentucky	1,391	10	4.8	1965	42%	2.9 – 5.1
18	Iowa	1,268	17	4.4	1967	41%	4.2 – 6.2
19	Pennsylvania	1,179	14	6.8	1983	73%	4.5 – 7.7
20	Nebraska	922	8	4.4	1967	54%	3.5 – 5.5
21	Illinois	823	8	3.1	1960	47%	3.2 – 4.6
22	Missouri	746	14	3.2	1962	51%	2.7 – 4.2
23	Minnesota	680	11	2.5	1960	42%	2.2 – 3.4
24	Kansas	631	5	3.2	1971	69%	2.7 – 4.2
25	Arizona	581	3	2.4	1975	54%	1.7 – 2.8
26	New Hampshire	559	4	2.9	1964	62%	1.9 – 3.2
27	Delaware	442	1	1.6	1980	42%	0.8 – 1.5
28	Connecticut	400	1	1.0	1968	31%	0.7 – 1.2
29	Colorado	316	4	1.9	1968	73%	1.9 – 2.8
30	North Dakota	75	1	0.4	1963	66%	0.4 – 0.6
31	Alaska	8	2	0.1	1952	60%	0.1 – 0.2
	Totals	**58,972**	**353**	**225.4**	**1967**	**47%**	**156.7 – 259.9**

[a] Data for average online year and average capacity factor reflect weighted averages based on total state capacity.

[b] The low end of the avoided annual CO_2 emissions range reflects replacement of coal with existing natural gas, and the high end of the range reflects replacement of coal with resources emitting zero carbon dioxide, such as wind, or reduced demand due to energy efficiency.

Table C-2. Summary of 153 Ripe-for-Retirement Coal Generators, by State (Low Estimate)

Rank	State	Capacity (MW)	No. of Coal Generators	Net Generation (million MWh)	Avg. Online Year[a]	Avg. Capacity Factor[a]	Avoided CO_2 Emissions (million tons)[b]
1	Georgia	3,997	14	17.7	1968	56%	11.9 - 18.7
2	Florida	1,628	6	5.8	1974	46%	4.4 - 6.6
3	Mississippi	1,438	4	5.3	1975	49%	4.3 - 6.3
4	Michigan	1,190	16	3.9	1962	40%	3.8 - 5.3
5	Alabama	1,159	7	3.9	1957	44%	2.9 - 4.4
6	South Carolina	907	6	1.6	1962	22%	1.1 - 1.7
7	Virginia	899	10	3.4	1970	48%	3.0 - 4.3
8	Wisconsin	678	9	2.9	1957	46%	2.5 - 3.6
9	Pennsylvania	651	10	4.4	1990	87%	3.2 - 4.9
10	Iowa	507.6	12	1.2	1965	28%	1.8 - 2.3
11	Missouri	446.5	8	2.0	1965	51%	1.6 - 2.4
12	New York	406.6	6	1.1	1960	36%	1.4 - 1.8
13	Minnesota	343.3	7	1.2	1961	37%	1.2 - 1.6
14	Ohio	283.5	5	0.1	1952	4%	0.1 - 0.2
15	North Carolina	251.7	5	0.5	1988	21%	0.5 - 0.7
16	Kentucky	216	4	0.8	1957	48%	0.7 - 1.1
17	New Hampshire	213.6	3	1.3	1957	71%	1.0 - 1.6
18	Colorado	204.3	3	1.3	1975	78%	1.4 - 1.9
19	Tennessee	175	1	0.3	1954	26%	0.2 - 0.4
20	Nebraska	167.8	2	0.7	1979	50%	0.7 - 1.0
21	West Virginia	164.6	2	1.0	1992	92%	0.8 - 1.2
22	Maryland	136	1	0.4	1959	37%	0.4 - 0.6
23	New Jersey	136	1	0.1	1962	7%	0.1. - 0.1
24	North Dakota	75	1	0.4	1963	66%	0.4 - 0.6
25	Indiana	51.1	4	0.0	1960	2%	0.2. - 0.2
26	Illinois	51	4	0.3	1965	60%	1.1 - 1.2
27	Kansas	49	1	0.3	1955	72%	0.3 - 0.4
28	Alaska	2.5	1	0.01	1952	42%	0.1 - 0.1
	Totals	**16,428**	**153**	**61.8**	**1967**	**47%**	**51.6 - 75.3**

[a] Data for average online year and average capacity factor reflect weighted averages based on total state capacity.

[b] The low end of the avoided annual CO_2 emissions range reflects replacement of coal with new natural gas, and the high end of the range reflects replacement of coal with renewable resources such as wind that emit zero carbon dioxide, or reduced demand due to energy efficiency.

Table C-3. State Ranking of Combined Coal Generators Announced for Retirement plus High Estimate of Coal Generators Identified as Ripe for Retirement

Rank	State	Combined Total		Announced Retirements		Ripe for Retirement High Estimate	
		Capacity (MW)	No. of Coal Generators	Capacity (MW)	No. of Coal Generators	Capacity (MW)	No. of Coal Generators
1	Ohio	8,962	59	6,763	43	2,198	16
2	Georgia	8,667	26	1,257	4	7,411	22
3	Alabama	7,377	30	844	6	6,534	24
4	Pennsylvania	5,024	40	3,845	26	1,179	14
5	North Carolina	5,017	39	2,904	26	2,113	13
6	Florida	4,998	15	1,183	4	3,815	11
7	Indiana	4,725	40	2,293	24	2,431	16
8	West Virginia	4,403	21	2,938	18	1,465	3
9	Virginia	4,314	34	2,114	14	2,201	20
10	South Carolina	4,066	26	1,125	15	2,942	11
11	Tennessee	3,985	23	125	1	3,860	22
12	Michigan	3,760	41	112	2	3,648	39
13	Illinois	3,246	25	2,423	17	823	8
14	Wisconsin	2,827	26	377	8	2,450	18
15	New York	2,661	21	1,160	9	1,502	12
16	Kentucky	2,623	19	1,233	9	1,391	10
17	Mississippi	2,406	8	-	-	2,406	8
18	Maryland	2,190	11	110	2	2,081	9
19	New Jersey	1,922	7	25	1	1,897	6
20	Nevada	1,878	3	1,878	3	-	-
21	Missouri	1,687	19	942	5	746	14
22	Iowa	1,553	31	285	14	1,268	17
23	Texas	1,490	3	1,490	3	-	-
24	Washington	1,460	2	1,460	2	-	-
25	Colorado	1,093	13	777	9	316	4
26	Delaware	1,052	7	610	6	442	1
27	Nebraska	922	8	-	-	922	8
28	Minnesota	919	12	239	1	680	11
29	Kansas	719	7	88	2	631	5
30	New Mexico	633	3	633	3	-	-
31	Connecticut	614	2	214	1	400	1
32	Oregon	601	1	601	1	-	-
33	Arizona	581	3	-	-	581	3
34	New Hampshire	559	4	-	-	559	4
35	Massachusetts	542	5	542	5	-	-
36	Oklahoma	473	1	473	1	-	-
37	Utah	189	2	189	2	-	-
38	North Dakota	75	1	-	-	75	1
39	Alaska	9	3	2	1	8	2
	Totals	**100,222**	**641**	**41,249**	**288**	**58,973**	**353**

APPENDIX D
Alternative Scenarios Summary Table

Table D-1. Summary of Results, Core Analysis vs. Alternative Scenarios

Scenario		Capacity (GW)	No. of Coal Generators	Net Generation (million MWh)	Percent of U.S. Electricity Consumption	Avoided CO_2 (million tons)*
Core analysis	Existing NGCC (high estimate)	59	353	225	6%	157 – 260
	New NGCC (low estimate)	16	153	62	2%	52 – 75
Alternative Scenarios						
High natural gas price	Existing NGCC	35	254	113	3%	83 – 134
	New NGCC	6	98	16	1%	17 – 23
Low natural gas price	Existing NGCC	138	556	651	18%	427 – 725
	New NGCC	36	232	154	4%	120 – 179
Carbon price	Existing NGCC	115	524	515	14%	348 – 584
	New NGCC	41	271	172	5%	138 – 204
Wind	Without tax credits	22	190	55	2%	69
	With tax credits	63	363	243	7%	279

* For all natural-gas-related scenarios, the low end of the avoided annual CO_2 emissions range reflects replacement of coal with existing or new natural gas (respectively, based on the specific scenario), and the high end of the range reflects replacement of coal with renewable resources such as wind, which emit zero carbon dioxide, or reduced demand for electricity due to energy efficiency.

APPENDIX E
Plant-level Listings by State

Table E-1. 288 Coal Generators Announced for Retirement or Conversion

State	Coal Plant	Plant Owner	Retiring Generators	Capacity (MW)	Online Year
Alabama	Widows Creek	Tennessee Valley Authority	6 of 8	844	1952 - 1954
Alaska	Che Power Plant	Aurora Energy, LLC	1 of 4	2	1952
Colorado	Arapahoe	Xcel Energy Inc.	1 of 2	46	1951
	Cameo	Xcel Energy Inc.	2 of 2	75	1957 - 1960
	Cherokee	Xcel Energy Inc.	3 of 4	421	1957 - 1962
	Valmont	Xcel Energy Inc.	1 of 1	192	1964
	W.N. Clark	Black Hills Corp.	2 of 2	44	1955 - 1959
Connecticut	Thames	S & S Deconstruction	1 of 1	214	1989
Delaware	Dover Steam Energy Center	NRG Energy, Inc.	1 of 1	18	1985
	Edge Moor Energy Center	Calpine Corp.	2 of 2	252	1954 - 1966
	Indian River	NRG Energy, Inc.	3 of 4	340	1957 - 1970
Florida	Central Power & Lime	JPMorgan Chase & Co.	1 of 1	125	1998
	Crist	Southern Co.	1 of 4	94	1959
	Crystal River	Progress Energy, Inc.	2 of 4	964	1966 - 1969
Georgia	Harllee Branch	Southern Co.	2 of 4	658	1965 - 1967
	Jack McDonough	Southern Co.	2 of 2	598	1963 - 1964
Illinois	Crawford	Edison International	2 of 2	597	1958 - 1961
	Fisk Street	Edison International	1 of 1	374	1968
	Hennepin Power Station	Dynegy Inc.	2 of 2	306	1953 - 1959
	Hutsonville	Ameren Corp.	2 of 2	150	1953 - 1954
	Jefferson Smurfit Madison County, IL	Smurfit-Stone Container Corp.	1 of 1	13	1958
	Lakeside	City Water, Light and Power	2 of 2	75	1961 - 1965
	Meredosia	Ameren Corp.	3 of 3	354	1948 - 1960
	Vermilion Power Station	Dynegy Inc.	2 of 2	182	1955 - 1956
	Will County	Edison International	2 of 4	371	1955
Indiana	Dean H. Mitchell	NiSource Inc.	3 of 3	384	1959 - 1970
	Eagle Valley	AES Corp.	4 of 4	302	1951 - 1956
	Edwardsport 7-8	Duke Energy Corp.	2 of 2	109	1949 - 1951
	Harding Street	AES Corp.	2 of 3	227	1958 - 1961
	Perry K	Citizens Energy Group	4 of 4	24	1925 - 2009
	R. Gallagher	Duke Energy Corp.	2 of 4	300	1959 - 1960
	State Line Energy	Dominion Resources, Inc.	2 of 2	334	1955 - 1962
	Tanners Creek	American Electric Power	3 of 4	520	1951 - 1954
	Whitewater Valley	City of Richmond	2 of 2	94	1955 - 1973

State	Coal Plant	Plant Owner	Retiring Generators	Capacity (MW)	Online Year
Iowa	Dubuque	Alliant Energy Corp.	1 of 3	15	1929
	Lansing	Alliant Energy Corp.	2 of 3	49	1949 - 1957
	Pella	City of Pella	2 of 2	38	1964 - 1972
	Prairie Creek	Alliant Energy Corp.	1 of 2	23	1951
	Sixth Street Station	Alliant Energy Corp.	6 of 6	85	1921 - 1950
	Sutherland Station	Alliant Energy Corp.	2 of 3	75	1955
Kansas	Riverton	Empire District Electric Co.	2 of 2	88	1950 - 1954
Kentucky	Big Sandy	American Electric Power	1 of 2	281	1963
	Cane Run	PPL Corp.	3 of 3	645	1962 - 1969
	Green River	PPL Corp.	2 of 2	189	1954 - 1959
	Henderson 1	Henderson City Utility	2 of 2	44	1956 - 1968
	Tyrone 3	PPL Corp.	1 of 1	75	1953
Maryland	R. Paul Smith Power Station	FirstEnergy Corp.	2 of 2	110	1947 - 1958
Massachusetts	Salem Harbor 1-3	Dominion Resources, Inc.	3 of 3	330	1952 - 1958
	Somerset	NRG Energy, Inc.	2 of 2	212	1959
Michigan	Presque Isle	Wisconsin Energy Corp.	2 of 7	112	1964 - 1966
Minnesota	Riverside	Xcel Energy Inc.	1 of 1	239	1964
Missouri	Asbury	Empire District Electric Co.	1 of 2	19	1986
	Meramec	Ameren Corp.	4 of 4	923	1953 - 1961
Nevada	Mohave	Edison International	2 of 2	1,636	1971
	TS Power Plant	Newmont Mining Corp.	1 of 1	242	2008
New Jersey	Howard Down	Vineland Municipal Electric Utility	1 of 1	25	1970
New Mexico	Four Corners	Arizona Public Service Co.	3 of 5	633	1963 - 1964
New York	Greenidge	AES Corp.	2 of 2	163	1950 - 1953
	Jennison	AES Corp.	1 of 1	60	1945
	Lovett	GenOn Energy, Inc.	1 of 1	200	1969
	Rochester 7 (Russell)	Iberdrola, S.A.	4 of 4	253	1948 - 1957
	Westover	AES Corp.	1 of 2	44	1943
North Carolina	Buck	Duke Energy Corp.	4 of 4	370	1941 - 1953
	Cape Fear	Progress Energy, Inc.	2 of 2	329	1956 - 1958
	Cliffside	Duke Energy Corp.	4 of 5	210	1940 - 1948
	Dan River	Duke Energy Corp.	3 of 3	290	1949 - 1955
	L.V. Sutton	Progress Energy, Inc.	3 of 3	672	1954 - 1972
	Lee	Progress Energy, Inc.	3 of 3	402	1951 - 1962
	Riverbend	Duke Energy Corp.	4 of 4	466	1952 - 1954
	W.H. Weatherspoon	Progress Energy, Inc.	3 of 3	166	1949 - 1952

State	Coal Plant	Plant Owner	Retiring Generators	Capacity (MW)	Online Year
Ohio	Akron Recycle Energy BFG	City of Akron	1 of 1	0.3	1979
	Ashtabula	FirstEnergy Corp.	1 of 1	256	1958
	Avon Lakes	GenOn Energy, Inc.	2 of 2	766	1949 - 1970
	Bay Shore	FirstEnergy Corp.	3 of 3	499	1959 - 1968
	Conesville	American Electric Power	1 of 4	162	1962
	Eastlake	FirstEnergy Corp.	5 of 5	1,257	1953 - 1972
	Jefferson Smurfit Pickaway County, OH	Smurfit-Stone Container Corp.	1 of 1	7	1981
	Lake Shore	FirstEnergy Corp.	1 of 1	256	1962
	Miami Fort	Duke Energy	2 of 4	263	1949 - 1960
	Muskingum River	American Electric Power	4 of 5	914	1953 - 1958
	Niles	GenOn Energy, Inc.	2 of 2	266	1954
	O.H. Hutchings	AES Corp.	2 of 6	138	1948 - 1949
	Picway	American Electric Power	1 of 1	106	1955
	R.E. Burger	FirstEnergy Corp.	3 of 3	416	1950 - 1955
	Richard Gorsuch	American Municipal Power, Inc.	4 of 4	200	1988
	Shelby Municipal Light	City of Shelby	4 of 4	37	1948 - 1973
	Walter C. Beckjord	Duke Energy Corp.	6 of 6	1,221	1952 - 1969
Oklahoma	Northeastern	American Electric Power	1 of 2	473	1979
Oregon	Boardman	Portland General Electric	1 of 1	601	1980
Pennsylvania	Armstrong Power Station	FirstEnergy Corp.	2 of 2	326	1958 - 1959
	Cromby 1	Exelon Corp.	1 of 1	188	1954
	Eddystone 1-2	Exelon Corp.	2 of 2	707	1960
	Elrama	GenOn Energy, Inc.	4 of 4	510	1952 - 1960
	Hunlock Power Station	UGI Corp.	1 of 1	49.9	1959
	New Castle	GenOn Energy, Inc.	3 of 3	348	1952 - 1964
	Portland	GenOn Energy, Inc.	2 of 2	427	1958 - 1962
	Shawville	GenOn Energy, Inc.	4 of 4	626	1954 - 1960
	Sunbury	Corona Power, LLC	4 of 4	438	1949 - 1953
	Titus	GenOn Energy, Inc.	3 of 3	225	1951 - 1953
South Carolina	Canadys	SCANA Corp.	3 of 3	490	1962 - 1967
	Dolphus M. Grainger	South Carolina Public Service Authority	2 of 2	163	1966
	McMeekin	SCANA Corp.	2 of 2	294	1958
	Savannah River (U.S. DOE)	U.S. Department of Energy	7 of 7	78	1952
	Urquhart	SCANA Corp.	1 of 1	100	1955
Tennessee	Johnsonville	Tennessee Valley Authority	1 of 10	125	1952
Texas	J.T. Deely	CPS Energy	2 of 2	932	1977 - 1978
	Welsh	American Electric Power	1 of 3	558	1980

State	Coal Plant	Plant Owner	Retiring Generators	Capacity (MW)	Online Year
Utah	Carbon	MidAmerican Energy Holdings Co.	2 of 2	189	1954 - 1957
Virginia	Chesapeake	Dominion Resources, Inc.	4 of 4	650	1953 - 1962
	Clinch River	American Electric Power	1 of 3	238	1961
	Glen Lyn	American Electric Power	2 of 2	338	1944 - 1957
	Potomac River	GenOn Energy, Inc.	5 of 5	514	1949 - 1957
	Yorktown	Dominion Resources, Inc.	2 of 2	375	1957 - 1959
Washington	Centralia	TransAltaCorp.	2 of 2	1,460	1972 -1973
West Virginia	Albright	FirstEnergy Corp.	3 of 3	278	1952 - 1954
	Kammer	American Electric Power	3 of 3	713	1958 - 1959
	Kawha River	American Electric Power	2 of 2	439	1953
	North Branch	Dominion Resources, Inc.	1 of 1	80	1992
	Philip Sporn	American Electric Power	5 of 5	1,106	1950 - 1960
	Rivesville	FirstEnergy Corp.	2 of 2	110	1943 - 1951
	Willow Island	FirstEnergy Corp.	2 of 2	213	1949 - 1960
Wisconsin	Alma	Dairyland Power Cooperative	3 of 5	45	1947 - 1951
	E.J. Stoneman	DTE Energy Co.	2 of 2	53	1952
	Menasha	City of Menasha	1 of 3	7	2006
	Valley Station	Wisconsin Energy Corp.	2 of 2	272	1968 - 1969

The following two tables list all of the coal generators we identified as ripe for retirement, under both our high and low estimates, by state. This report is a static analysis that takes a "snapshot" of the coal fleet and its relative economic competitiveness compared with natural gas combined-cycle power plants and cleaner alternatives. While this report evaluates some of the most important criteria affecting the future economic viability of coal-fired generators, other localized unit-specific factors including reliability and related issues will help determine whether coal plant owners decide whether to retrofit or retire specific individual units.

For each coal-fired power plant listed in the high estimate (Table E-2), we indicate the number of coal generators at that plant deemed ripe for retirement because they are uneconomic compared with an existing natural gas power plant. For some plants, all generators at that plant are identified for potential closure, while for other plants, those units that remain competitive with existing natural gas are not identified for closure.

Table E-2. High Estimate of 353 Coal Generators Identified as Ripe for Retirement

State	Plant	Plant Owner	Generators	Capacity (MW)	Online Year
Alabama	Greene County	Southern Company	2 of 2	568	1965 - 1966
	Gadsden	Southern Company	2 of 2	138	1949
	Charles R. Lowman	PowerSouth Energy Cooperative	1 of 3	66	1969
	Gorgas	Southern Company	4 of 5	628	1951 - 1958
	Barry	Southern Company	5 of 5	1,771	1954 - 1971
	Colbert	Tennessee Valley Authority	5 of 5	1,350	1955 - 1965
	E.C. Gaston	Southern Company	5 of 5	2,013	1960 - 1974
Alaska	Che Power Plant	Aurora Energy, LLC	2 of 4	8	1952
Arizona	Apache Station	Arizona Electric Power Cooperative Inc.	2 of 2	408	1979
	H. Wilson Sundt Generating Station	UniSource Energy	1 of 1	173	1967
Colorado	Arapahoe	Xcel Energy Inc.	1 of 2	112	1955
	Martin Drake Plant	Colorado Springs Utilities	2 of 3	125	1962 - 1968
	Nucla	Tri-State Generation & Transmission Association, Inc.	1 of 4	79	1991
Connecticut	Bridgeport Harbor 3	Public Service Enterprise Group Inc.	1 of 1	400	1968
Delaware	Indian River	NRG Energy, Inc.	1 of 4	442	1980
Florida	Scholz	Southern Company	1 of 1	49	1953
	Deerhaven	Gainesville Regional Utilities	1 of 1	251	1981
	C.D. McIntosh, Jr. 3	Multi-owned	1 of 1	364	1982
	Cedar Bay Generating	Goldman Sachs Group, Inc.	1 of 1	292	1994
	Lansing Smith	Southern Company	2 of 2	340	1965 - 1967
	Crystal River	Progress Energy, Inc.	2 of 4	1,478	1982 - 1984
	Crist	Southern Company	3 of 4	1,041	1961 - 1973

State	Plant	Plant Owner	Generators	Capacity (MW)	Online Year
Georgia	Plant Crisp	Crisp County Power Commission	1 of 1	13	1957
	Mitchell	Southern Company	1 of 1	163	1964
	Kraft 1-3	Southern Company	3 of 3	208	1958 - 1965
	Harllee Branch	Southern Company	2 of 4	1,088	1968 - 1969
	Bowen	Southern Company	4 of 4	3,499	1971 - 1975
	Hammond	Southern Company	4 of 4	953	1954 - 1970
	Yates	Southern Company	7 of 7	1,487	1950 -1974
Illinois	Joliet 9 Station	Edison International	1 of 1	360	1959
	Pearl Station	Prairie Power, Inc.	1 of 1	22	1967
	Tuscola Station	Duke Energy Corp.	3 of 3	18	1953 - 2001
	Will County	Edison International	1 of 4	299	1957
	Marion	Southern Illinois Power Cooperative	1 of 4	33	1963
	Dallman	City Water, Light and Power	1 of 4	90	1968
Indiana	Jasper 2	City of Jasper	1 of 1	15	1968
	Logansport	City of Logansport	1 of 2	18	1958
	F.B. Culley	Vectren Corp.	1 of 2	104	1966
	Frank E. Ratts	Hoosier Energy Rural Electric Co-op Inc.	1 of 2	117	1970
	Crawfordsville	Crawfordsville Electric Light & Power	2 of 2	24	1955 - 1965
	Peru	City of Peru	2 of 2	35	1949 - 1959
	Tanners Creek	American Electric Power Company	1 of 4	580	1964
	Warrick	ALCOA	1 of 4	323	1970
	R.M. Schahfer	NiSource Inc.	1 of 4	556	1979
	R. Gallagher	Duke Energy Corp.	2 of 4	300	1958 - 1961
	Wabash River Station	Duke Energy Corp.	3 of 5	361	1953 - 1956
Iowa	Earl F. Wisdom	Corn Belt Power Cooperative	1 of 1	33	1960
	M.L. Kapp	Alliant Energy Corp.	1 of 1	218	1967
	Prairie Creek	Alliant Energy Corp.	1 of 2	50	1958
	Fair Station	Central Iowa Power Cooperative	1 of 2	38	1967
	Ames	City of Ames	2 of 2	109	1968 - 1982
	Riverside (IA)	MidAmerican Energy Holdings Co.	2 of 2	141	1949 - 1961
	Streeter Station	City of Cedar Falls	2 of 2	52	1963 - 1973
	Sutherland ST	Alliant Energy Corp.	1 of 3	82	1961
	Lansing	Alliant Energy Corp.	1 of 3	275	1977
	Dubuque	Alliant Energy Corp.	2 of 3	66	1952 - 1959
	Muscatine	Muscatine Power & Water	1 of 4	75	1969
	Walter Scott, Jr. Energy Center	MidAmerican Energy Holdings Co.	2 of 4	131	1954 - 1958

State	Plant	Plant Owner	Generators	Capacity (MW)	Online Year
Kansas	Lawrence	Westar Energy, Inc.	1 of 3	49	1955
	Nearman Creek	City of Kansas City	1 of 1	261	1981
	Quindaro	City of Kansas City	2 of 2	239	1965 - 1971
	Tecumseh	Westar Energy, Inc.	1 of 2	82	1957
Kentucky	Dale	East Kentucky Power Coop. Inc.	4 of 4	216	1954 - 1960
	E.W. Brown	PPL Corp.	2 of 3	560	1957 - 1971
	J. Sherman Cooper	East Kentucky Power Coop. Inc.	2 of 2	344	1965 - 1969
	R.A. Reid	Big Rivers Electric Corp.	1 of 1	96	1966
	Shawnee	Tennessee Valley Authority	1 of 10	175	1953 - 1956
Maryland	Warrior Run Cogeneration	AES Corp.	1 of 1	229	1999
	C.P. Crane	Constellation Energy Group, Inc.	2 of 2	400	1961 - 1963
	Dickerson	GenOn Energy, Inc.	3 of 3	588	1959 - 1962
	Herbert A. Wagner 2-3	Constellation Energy Group, Inc.	1 of 2	136	1959
	Chalk Point 1-2	GenOn Energy, Inc.	2 of 2	728	1964 - 1965
Michigan	Harbor Beach	DTE Energy Company	1 of 1	121	1968
	Erickson	Lansing Board of Water & Light	1 of 1	155	1973
	Endicott Generating	Michigan South Central Power Agency	1 of 1	55	1982
	J.B. Sims	City of Grand Haven	1 of 1	80	1983
	Shiras	City of Marquette	1 of 2	21	1972
	B. C. Cobb	CMS Energy Corp.	2 of 2	313	1956 - 1957
	J.C. Weadock	CMS Energy Corp.	2 of 2	313	1955 - 1958
	Wyandotte	Wyandotte Municipal Service Commission	2 of 2	54	1958 - 1986
	Escanaba	City of Escanaba	2 of 2	23	1958
	James De Young	City of Holland	2 of 3	41	1951 - 1969
	Trenton Channel	DTE Energy Company	2 of 3	240	1949 - 1950
	J.R. Whiting	CMS Energy Corp.	3 of 3	345	1952 - 1953
	White Pine Copper Refinery	Traxys North America LLC	3 of 3	60	1954
	St. Clair	DTE Energy Company	5 of 6	1,003	1953 - 1961
	Eckert Station	Lansing Board of Water & Light	6 of 6	375	1954 - 1970
	Presque Isle	Wisconsin Energy Corporation	5 of 7	450	1974 - 1979
Minnesota	Willmar	Willmar Municipal Utility Commission	1 of 1	18	1970
	Austin Northeast	City of Austin	1 of 1	32	1971
	Hoot Lake	Otter Tail Corporation	2 of 2	129	1959 - 1964
	Black Dog Station	Xcel Energy Inc.	2 of 2	294	1955 - 1960
	SylLaskin	ALLETE, Inc.	2 of 2	116	1953
	Silver Lake	Rochester Public Utilities	3 of 3	91	1953 - 1969

State	Plant	Plant Owner	Generators	Capacity (MW)	Online Year
Mississippi	Henderson	Greenwood Utilities Commission	2 of 2	33	1960 - 1967
	Jack Watson	Southern Company	2 of 2	877	1968 - 1973
	R.D. Morrow	South Mississippi Electric Power Assoc.	2 of 2	400	1978
	Victor J. Daniel, Jr.	Southern Company	2 of 2	1,097	1977 - 1981
Missouri	Lake Road	Great Plains Energy Inc.	1 of 1	90	1966
	Chamois	Central Electric Power Cooperative	2 of 2	59	1953 - 1960
	Columbia	City of Columbia	2 of 2	39	1957 - 1965
	Missouri City	City of Independence City	2 of 2	46	1954
	Montrose	Great Plains Energy Inc.	1 of 3	188	1958
	Blue Valley	City of Independence	3 of 3	115	1958 - 1965
	James River Power Station	City Utilities of Springfield	3 of 5	209	1960 - 1970
Nebraska	Lon Wright	City of Fremont	1 of 3	92	1977
	North Omaha	Omaha Public Power District	5 of 5	645	1954 - 1968
	Platte	City of Grand Island	1 of 1	110	1982
	Whelan Energy Center	Multi-owned	1 of 1	76	1981
New Hampshire	Merrimack	Northeast Utilities	2 of 2	459	1960 - 1968
	Schiller Coal	Northeast Utilities	2 of 2	100	1952 - 1957
New Jersey	B.L. England 1-2	Multi-owned	2 of 2	299	1962 - 1964
	Chambers Cogeneration	Multi-owned	1 of 1	285	1994
	Mercer	Public Service Enterprise Group Inc.	2 of 2	653	1960 - 1961
	Hudson 2	Public Service Enterprise Group Inc.	1 of 1	660	1968
New York	Black River Generation	Multi-owned	1 of 1	56	1989
	Westover	AES Corporation	1 of 2	75	1951
	C.R. Huntley	NRG Energy, Inc.	1 of 2	218	1957
	Syracuse Energy Corp.	GDF Suez SA	1 of 2	91	1991
	Danskammer 3-4	Dynegy Inc.	2 of 2	387	1959 - 1967
	Samuel A. Carlson	Jamestown Board of Public Utilities	2 of 2	49	1951 - 1968
	Dunkirk	NRG Energy, Inc.	4 of 4	627	1950 - 1960
North Carolina	Elizabethtown ST	Vulcan Capital	1 of 1	35	1985
	Lumberton ST	Vulcan Capital	1 of 1	35	1985
	Roxboro ST	Capital Power Corp.	1 of 1	68	1987
	Southport ST	Capital Power Corp.	2 of 2	135	1987
	Rocky Mount/D.C. Battle	Multi-owned	2 of 2	115	1990
	Cliffside	Duke Energy Corp.	1 of 5	571	1972
	G.G. Allen	Duke Energy Corp.	5 of 5	1,155	1957 - 1961
North Dakota	R.M. Heskett Generating Station	MDU Resources Group, Inc.	1 of 2	75	1963

State	Plant	Plant Owner	Generators	Capacity (MW)	Online Year
Ohio	Hamilton	City of Hamilton	2 of 2	76	1965 - 1975
	Orrville	City of Orrville	1 of 3	25	1971
	O.H. Hutchings	AES Corporation	4 of 5	276	1950 - 1953
	Painesville	City of Painesville	3 of 3	46	1953 - 1990
	W.H. Sammis	FirstEnergy Corp.	6 of 7	1,776	1959 - 1969
Pennsylvania	Mitchell Power Station 3	FirstEnergy Corp.	1 of 1	299	1963
	Westwood Generating Station	Integrys Energy Group, Inc.	1 of 1	36	1987
	John B. Rich Memorial	Gilberton Power Company	1 of 1	88	1988
	Wheelabrator Frackville	Waste Management, Inc.	1 of 1	48	1988
	Northeastern Power Cogeneration	GDF Suez SA	1 of 1	58	1989
	Ebensburg Power Company	McDermott International	1 of 1	58	1990
	St. Nicholas Cogeneration	Schuylkill Energy Resource, Inc.	1 of 1	99	1990
	Cambria Cogeneration	Northern Star Generation	1 of 1	98	1991
	Panther Creek	Multi-owned	1 of 1	94	1992
	Piney Creek Project	Colmac Clarion, Inc.	1 of 1	36	1992
	Scrubgrass	Pacific Gas and Electric Co.	1 of 1	95	1993
	Colver Power Project	Constellation Energy Group, Inc.	1 of 1	118	1995
	Beaver Valley Station	AES Corp.	1 of 2	35	1987
	Montour	PPL Corp.	1 of 3	17	1973
South Carolina	H.B. Robinson Coal	Progress Energy, Inc.	1 of 1	207	1960
	Williams	SCANA Corp.	1 of 1	633	1973
	Wateree	SCANA Corp.	2 of 2	772	1970 - 1971
	Jefferies	South Carolina Public Service Authority	2 of 2	346	1970
	W.S. Lee	Duke Energy Corp.	3 of 3	355	1951 - 1958
	Winyah	South Carolina Public Service Authority	2 of 4	630	1977 - 1980
Tennessee	John Sevier	Tennessee Valley Authority	4 of 4	800	1955 - 1957
	Kingston	Tennessee Valley Authority	9 of 9	1,700	1954 - 1955
	Johnsonville	Tennessee Valley Authority	9 of 10	1,360	1951 - 1959
Virginia	Altavista	Dominion Resources, Inc.	1 of 1	71	1992
	Hopewell (Polyester)	Dominion Resources, Inc.	1 of 1	71	1992
	Southampton	Dominion Resources, Inc.	1 of 1	71	1992
	Bremo Bluff	Dominion Resources, Inc.	2 of 2	254	1950 - 1958
	James River Station	Goldman Sachs Group, Inc.	2 of 2	115	1988
	Portsmouth Station	Multi-owned	2 of 2	115	1988
	Mecklenburg Cogeneration	Dominion Resources, Inc.	2 of 2	140	1992
	Clinch River	American Electric Power Company, Inc.	2 of 3	475	1958
	Chesterfield	Dominion Resources, Inc.	3 of 4	659	1952 - 1964
	Spruance Genco	Multi-owned	4 of 4	230	1992

State	Plant	Plant Owner	Generators	Capacity (MW)	Online Year
West Virginia	Morgantown Energy Facility	GenOn Energy, Inc.	1 of 1	69	1991
	Grant Town Cogen	Edison International	1 of 1	96	1992
	John E. Amos	American Electric Power Company, Inc.	1 of 3	1,300	1973
Wisconsin	Genoa	Dairyland Power Cooperative	1 of 1	346	1969
	Milwaukee County	Wisconsin Energy Corp.	1 of 1	11	1996
	Nelson Dewey	Alliant Energy Corp.	2 of 2	200	1959 - 1962
	Edgewater	Alliant Energy Corp.	1 of 3	60	1951
	Menasha	Menasha Electric & Water Utility	1 of 3	14	1964
	Weston	Integrys Energy Group, Inc.	2 of 4	142	1954 - 1960
	Pulliam	Integrys Energy Group, Inc.	4 of 4	350	1949 - 1964
	South Oak Creek	Wisconsin Energy Corp.	4 of 4	1,192	1959 - 1967
	Alma	Dairyland Power Cooperative	2 of 5	136	1957 - 1960

For each coal-fired power plant listed below in the low estimate (Table E-3), we indicate the number of coal generators at that plant deemed ripe for retirement because they are uneconomic compared with a new natural gas power plant. For some plants, all generators at that plant are identified for potential closure, while for other plants, those units that remain competitive with existing natural gas are not identified for closure.

Table E-3. Low Estimate of 153 Coal Generators Identified as Ripe for Retirement

State	Coal Plant	Plant Owner	Generators	Capacity (MW)	Online Year
Alabama	Greene County	Alabama Power Company	1 of 2	299	1965
	Colbert	Tennessee Valley Authority	1 of 5	200	1955
	Barry	Alabama Power Company	1 of 5	272	1959
	Gadsden	Alabama Power Company	2 of 2	138	1949
	Gorgas	Alabama Power Company	2 of 5	250	1951 - 1952
Alaska	Che Power Plant	Golden Valley Electric Association Inc.	1 of 4	3	1952
Colorado	Nucla	Tri-State Generation & Transmission Association, Inc.	1 of 4	79	1991
	Martin Drake Plant	Colorado Springs Utilities	2 of 3	125	1962 - 1968
Florida	Scholz	Gulf Power Company	1 of 1	49	1953
	Cedar Bay Generating	JEA	1 of 1	292	1994
	Lansing Smith	Gulf Power Company	2 of 2	340	1965 - 1967
	Crist	Gulf Power Company	2 of 4	948	1970 - 1973
Georgia	Mitchell	Georgia Power Company	1 of 1	163	1964
	Harllee Branch	Georgia Power Company	1 of 4	544	1969
	Bowen	Georgia Power Company	2 of 4	1,595	1971 - 1972
	Kraft 1-3	Georgia Power Company	3 of 3	208	1958 - 1965
	Yates	Georgia Power Company	7 of 7	1,487	1950 -1974
Illinois	Marion	Southern Illinois Power Cooperative	1 of 4	33	1963
	Tuscola Station	Ameren Illinois Company	3 of 3	18	1953 - 2001
Indiana	Jasper 2	City of Jasper	1 of 1	15	1968
	Peru	City of Peru	1 of 2	13	1949
	Crawfordsville	Crawfordsville Electric Light & Power Co.	2 of 2	24	1955 - 1965
Iowa	Earl F. Wisdom	Corn Belt Power Co-op.	1 of 1	33	1960
	Riverside	MidAmerican Energy Company	1 of 2	5	1949
	Fair Station	Central Iowa Power Cooperative	1 of 2	38	1967
	Sutherland ST	Interstate Power and Light Company	1 of 3	82	1961
	Walter Scott, Jr. Energy Center	MidAmerican Energy Company	1 of 4	49	1954
	Muscatine	Muscatine Power & Water	1 of 4	75	1969
	Streeter Station	City of Cedar Falls	2 of 2	52	1963 - 1973
	Ames	City of Ames	2 of 2	109	1968 - 1982
	Dubuque	ITC Midwest LLC	2 of 3	66	1952 - 1959

State	Coal Plant	Plant Owner	Generators	Capacity (MW)	Online Year
Kansas	Lawrence	Westar Energy (KPL)	1 of 3	49	1955
Kentucky	Dale	East Kentucky Power Cooperative Inc.	4 of 4	216	1954 - 1960
Maryland	Herbert A. Wagner 2-3	Baltimore Gas and Electric Company	1 of 2	136	1959
Michigan	Harbor Beach	Intertiol Transmission Company	1 of 1	121	1968
	Endicott Generating	Michigan South Central Power Agency	1 of 1	55	1982
	Trenton Channel	Detroit Edison Company	1 of 3	120	1950
	James De Young	City of Holland	1 of 3	29	1969
	Presque Isle	Wisconsin Electric Power Company	1 of 7	90	1975
	Wyandotte	Wyandotte Municipal Service Commission	2 of 2	54	1958 - 1986
	J.R. Whiting	Michigan Electric Transmission Company, LLC	3 of 3	345	1952 - 1953
	Eckert Station	Lansing Board of Water & Light	6 of 6	375	1954 - 1970
Minnesota	Austin Northeast	City of Austin	1 of 1	32	1971
	Hoot Lake	Otter Tail Power Company	2 of 2	129	1959 - 1964
	Syl Laskin	ALLETE (Minnesota Power)	2 of 2	116	1953
	Silver Lake	Rochester Public Utilities	2 of 3	66	1953 -1969
Missouri	Lake Road	KCP&L Greater Missouri Operations Company	1 of 1	90	1966
	Chamois	Associated Electric Cooperative Inc.	1 of 2	44	1960
	Blue Valley	City of Independence	1 of 3	65	1965
	Columbia	City of Columbia	2 of 2	39	1957 - 1965
	James River Power Station	City Utilities of Springfield	3 of 5	209	1960 - 1970
Mississippi	Henderson	Entergy Mississippi, Inc.	1 of 2	13	1960
	Victor J. Daniel, Jr.	Mississippi Power Company	1 of 2	548	1981
	Jack Watson	Mississippi Power Company	2 of 2	877	1968 - 1973
Nebraska	Whelan Energy Center	Nebraska Public Power District	1 of 1	76	1981
	Lon Wright	City of Fremont	1 of 3	92	1977
New Hampshire	Merrimack	Public Service Company of New Hampshire	1 of 2	114	1960
	Schiller Coal	Public Service Company of New Hampshire	2 of 2	100	1952 - 1957
New Jersey	B.L. England 1-2	Atlantic City Electric Company	1 of 2	136	1962

State	Coal Plant	Plant Owner	Generators	Capacity (MW)	Online Year
New York	Westover	New York State Electric & Gas Corporation	1 of 2	75	1951
	Syracuse Energy Corporation	Niagara Mohawk Power Corporation	1 of 2	91	1991
	Samuel A. Carlson (Jamestown)	Jamestown Board of Public Utilities	2 of 2	49	1951 - 1968
	Dunkirk	Niagara Mohawk Power Corporation	2 of 4	192	1950
North Carolina	Elizabethtown ST	Carolina Power & Light Company	1 of 1	35	1985
	Lumberton ST	Carolina Power & Light Company	1 of 1	35	1985
	Roxboro ST	Carolina Power & Light Company	1 of 1	68	1987
	Rocky Mount/D.C. Battle	Virginia Electric and Power Company	2 of 2	115	1990
North Dakota	R.M. Heskett Generating Station	MDU Resources Group, Inc.	1 of 2	75	1963
Ohio	Painesville	City of Painesville	1 of 3	8	1953
	O.H. Hutchings	Dayton Power and Light Company	4 of 6	276	1950 - 1953
Pennsylvania	Westwood Generating Station	PPL Electric Utilities Corporation	1 of 1	36	1987
	John B. Rich Memorial Power Station	Pennsylvania Power Company	1 of 1	88	1988
	Wheelabrator Frackville Energy Company	PPL Electric Utilities Corporation	1 of 1	48	1988
	Northeastern Power Cogeneration Facility	PPL Electric Utilities Corporation	1 of 1	58	1989
	Ebensburg Power Company	Pennsylvania Electric Company	1 of 1	58	1990
	St. Nicholas Cogeneration	PPL Electric Utilities Corporation	1 of 1	99	1990
	Cambria Cogeneration	Pennsylvania Electric Company	1 of 1	98	1991
	Piney Creek Project	Pennsylvania Electric Company	1 of 1	36	1992
	Scrubgrass	Pennsylvania Electric Company	1 of 1	95	1993
	Beaver Valley ST	Duquesne Light Company	1 of 2	35	1987
South Carolina	H.B. Robinson Coal	Carolina Power & Light Company	1 of 1	207	1960
	Jefferies	South Carolina Public Service Authority	2 of 2	346	1970
	W.S. Lee	Duke Energy Carolinas, LLC	3 of 3	355	1951 -1958
Tennessee	Kingston	Tennessee Valley Authority	1 of 9	175	1954

State	Coal Plant	Plant Owner	Generators	Capacity (MW)	Online Year
Virginia	Bremo Bluff	Virginia Electric and Power Company	2 of 2	254	1950 - 1958
	James River ST	Virginia Electric and Power Company	2 of 2	115	1988
	Chesterfield	Virginia Electric and Power Company	2 of 4	300	1952 -1960
	Spruance Genco	Virginia Electric and Power Company	4 of 4	230	1992
West Virginia	Morgantown Energy Facility	Allegheny Electric Cooperative Inc.	1 of 1	69	1991
	Grant Town Cogen	Monongahela Power Company	1 of 1	96	1992
Wisconsin	Nelson Dewey	Wisconsin Power and Light Company	2 of 2	200	1959 - 1962
	Weston	Wisconsin Public Service Corporation	2 of 4	142	1954 -1960
	Alma	Dairyland Power Cooperative	2 of 5	136	1957 - 1960
	Pulliam	Wisconsin Public Service Corporation	3 of 4	201	1949 - 1958

Ripe for Retirement

The Case for Closing America's Costliest Coal Plants

For decades, coal has powered America. But today, more than three-quarters of U.S. coal-fired power plants have outlived their 30-year life span. Most are inefficient and lack essential modern pollution controls, causing significant damage to public health and the environment. They also face an increasingly uncertain economic future: growing competition from abundant, cheaper, cleaner, and reliable energy sources (such as natural gas, renewable energy, and energy efficiency) is making it harder for coal to compete.

This report examines the economic viability of our nation's coal-fired electricity generating units. More than a hundred U.S. plant owners have already concluded that keeping their outdated facilities running is a bad investment and have elected to retire them instead, but we have found that there are many more uncompetitive generating units that are "ripe for retirement."

By shifting the electricity sector's investment dollars away from extending the life of obsolete coal plants and toward renewable energy, energy efficiency, and—to a more limited extent—natural gas, we have a historic opportunity to accelerate America's transition to a cleaner energy future.

The Union of Concerned Scientists is the leading science-based nonprofit working for a healthy environment and a safer world.

This report is available online (in PDF format) at *www.ucsusa.org/ripeforretirement*.

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