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INTRODUCTION

Xcel Energy is widely recognized for its commitment to environmental leadership. The proactive measures we have taken and continue to take to modernize our generation fleet and to reduce the environmental impacts of providing electric service position the Company well to manage the uncertainty associated with pending federal and state environmental regulations. We are:

- Ranked by the American Wind Energy Association (AWEA) as the number one wind provider in the country for ten years running;
- Ranked by the Solar Electric Power Association (SEPA) as the number seven utility in the nation for solar capacity on our system;
- On track to meet some of the most aggressive state renewable energy requirements in the country;
- Implementing industry-leading carbon dioxide ($CO_{2)}$ emission reduction projects such as the Metropolitan Emissions Reduction Project (MERP) and additional coal plant retirements of our Black Dog and Bay Front units;
- Administering one of the nation's most successful demand side management (DSM) programs; and
- Supporting and pursuing innovative energy technologies such as smart grid technologies, energy storage, and electric vehicles.

Our 2013 annual Corporate Responsibility Report contains more details on these issues and our achievements.[1]

This Appendix provides additional detail regarding the evolving environmental regulations impacting this Resource Plan. In this Appendix, we summarize the complex array of mandates and goals the Company faces and highlight areas of uncertainty where we must make decisions with incomplete information about how these regulations and mandates will evolve in the coming years. This uncertainty makes it important to retain flexibility and a broad array of generation options even while continuing to reduce our overall carbon emissions.

I. FEDERAL ENVIRONMENTAL REGULATIONS

Since the Company's last resource plan, multiple new air, water and waste regulations have been updated and adopted by the U.S. Environmental Protection Agency (EPA),

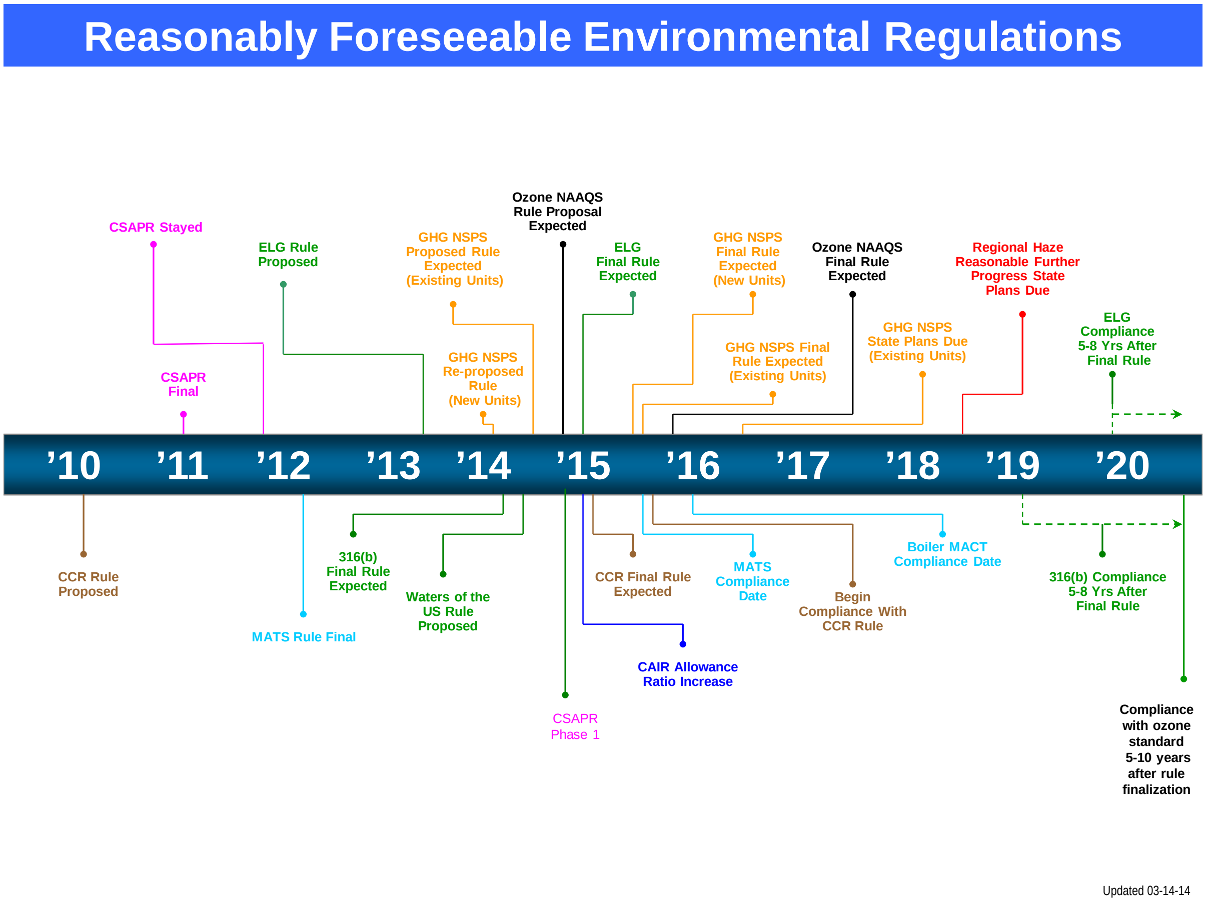
[1] This report is available at:
http://www.xcelenergy.com/About_Us/Our_Company/Company_Profile/Corporate_Responsibility_Report.

increasing our knowledge of what will be required to maintain compliance at our facilities. Regulations for criteria pollutants, particularly oxides of nitrogen, sulfur dioxide, particulate matter, and ozone, continue to be updated and are likely to impose additional pollution controls at some of our power plants at some point in the future. The EPA has been developing updated requirements for water quality at thermal power plants and management of coal combustion residuals at coal-fired power plants.

EPA proposals for regulation of carbon dioxide emissions from both new and existing power plants were released in 2014 and are slated to be finalized in 2015. These CO_2 regulations could be the most significant regulatory driver affecting our resource planning decisions, but the final rules are not yet available and state implementation plans for CO_2 regulation at existing power plants will not be final until 2016 to 2018. As a result, we continue to experience significant uncertainty surrounding environmental regulation, which requires us to maintain flexibility in response options.

Figure 1 below illustrates the array of environmental regulations recently adopted or in development that may affect NSP System generation facilities.

Figure 1: Reasonably Foreseeable Environmental Regulations Affecting NSP System Generation Facilities



Source: Xcel Energy

II. STATUS OF EACH REGULATION

This section summarizes the current status and remaining unknowns about each regulation, along with the potential impacts on our thermal generation resources.

A. Greenhouse Gas (GHG) Emissions from New and Existing Power Plants

The EPA began pursuing the regulation of greenhouse gas emissions as a result of the U.S. Supreme Court's 2007 finding in *Massachusetts v. EPA* that GHGs are "air pollutants" that can be regulated under the Clean Air Act (CAA).[2] In 2009, the EPA

[2] See http://www.supremecourt.gov/opinions/06pdf/05-1120.pdf and http://www.law.cornell.edu/supct/html/05-1120.ZS.html.

issued its "endangerment" finding that GHG concentrations in the atmosphere pose a threat to public health and welfare, and its "cause or contribute" finding that GHG emissions from motor vehicles contribute to these GHG concentrations.[3] Based on this finding, the EPA adopted GHG emission standards for light and heavy duty vehicles.

Whether or not the EPA would pursue regulation of GHGs under the CAA was, for a time, linked to the possible passage of national climate legislation. The U.S. House of Representatives passed an economy-wide GHG cap-and-trade bill in 2009, but similar legislation failed to pass the Senate. Other federal regulatory approaches – a carbon tax, national renewable portfolio standard, or clean energy portfolio standard – have also been discussed, but none of these approaches appears likely to receive the necessary support for passage in the near term. In the absence of legislation, the EPA is moving forward with GHG regulation under the CAA.

1. *GHG Permitting*

The EPA adopted permitting requirements for GHG emissions from new and modified large stationary sources that became effective in 2011. These permitting requirements, found under the New Source Review (NSR) and Prevention of Significant Deterioration (PSD) sections of the CAA, are applied to new power plant construction or power plant modifications that increase GHG emissions above a certain threshold. In June 2014, the U.S. Supreme Court held that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source of GHGs is a major source required to obtain a PSD or operating permit; however, if a new or modified stationary source becomes subject to these permitting requirements by exceeding emission thresholds for other air pollutants (so called "anyway sources"), the EPA could continue to require the permitting process to evaluate the Best Available Control Technology (BACT) for GHG emissions. With respect to such "anyway sources," the EPA is continuing to apply its threshold that any new or modified source increasing its GHG emissions by more than 75,000 tons per year of CO_2 equivalents (CO_2e) must evaluate BACT for GHGs in its permit application.

2. *GHG Emission Standards for New Power Plants*

In June 2013, President Obama issued a *Presidential Memorandum on Power Sector Carbon Pollution Standards*, directing the EPA to use its authority under Section 111 of the CAA to develop GHG emission standards for new and existing power plants. The

[3] See http://epa.gov/climatechange/endangerment.

memorandum directed the EPA to issue proposed GHG emissions standard for new power plants under Section 111(b) by September 20, 2013.[4] The EPA did so, and the proposed rule was published in the Federal Register on January 8, 2014.[5]

The EPA's proposed GHG New Source Performance Standard (NSPS) for newly-constructed power plants creates two regulated source categories: 1) fossil fuel-fired electric utility steam generating units and Integrated Gasification Combined Cycle (IGCC) units, which are required to meet an emission performance standard of 1,100 pounds of CO_2 per megawatt-hour (lbs CO_2/MWh); and 2) natural gas-fired stationary combustion turbines, of which larger turbines are required to meet a standard of 1,000 lbs CO_2/MWh and smaller turbines are required to meet a standard of 1,100 lbs CO_2/MWh. The rule effectively bans the construction of new coal power plants unless they capture and sequester around half of their CO_2 emissions. The EPA is expected to finalize this GHG NSPS for new sources in early 2015.

The EPA proposes that the NSPS will not apply to modified or reconstructed existing power plants. In addition, installation of control equipment on existing plants would not constitute a "modification" to those plants under the NSPS program.

While Xcel Energy disagrees with certain aspects of the proposed rule – including whether carbon capture and sequestration (CCS) meets the statutory tests to qualify as the Best System of Emission Reduction for new coal units – we currently expect this rule to have limited effect on our resource planning. Xcel Energy does not currently plan to build any new coal-fired power plants, with or without CCS, and any new natural gas plants we may build will comply with the proposed NSPS for those units.

3. *GHG Emission Standards for Modified and Reconstructed Power Plants*

In June 2014, the EPA published a proposed NSPS under CAA Section 111(b) that would apply to GHG emissions from fossil fuel-fired utility boilers, IGCC units, and

[4] See http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

[5] *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Generating Units*, Docket No. EPA-HQ-OAR-2013-0495, 79 Fed. Reg. 1,430 (Jan. 8, 2014). See http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants. Note that EPA released its first proposed New Source Performance Standard rule for GHG emissions from new sources in April 2012. This proposal would have required any new fossil fuel-fired electric generating unit (EGU) source to meet an emission performance standard of 1,000 lbs CO_2/MWh. The EPA has withdrawn that proposal and replaced it with the January 2014 proposal described here.

natural gas-fired stationary combustion turbines that are modified or reconstructed.[6] A modification is defined as a change to an existing source that increases the source's maximum achievable hourly rate of emissions. A reconstruction is defined as the replacement of components such that the capital cost of the new components exceeds 50 percent of the capital cost of an entirely new comparable unit.

The proposed standards are not based on, and would not require, the installation of CCS technology. Instead, the proposed standard for fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) would require a combination of best operating practices and equipment upgrades. Modified sources would be required to meet a unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification) plus an additional 2 percent emission reduction. In a second "co-proposed" alternative, sources that are modified after becoming subject to a CAA 111(d) would be required to meet a unit-specific emission limit determined by the 111(b) implementing authority based on the results of an energy efficiency improvement audit.

The proposal for gas-fired power plants would require emission standards based on efficient combined cycle technology. Modified sources with heat input greater than 850 MMBtu/hr would be required to meet an emission rate limit of 1,000 lb CO_2/MWh-gross; modified sources with heat input less than or equal to 850 MMBtu/hr would be required to meet an emission rate limit of 1,100 lb CO_2/MWh-gross.

The EPA proposes that all existing sources that are modified or reconstructed after they are already subject to a CAA section 111(d) plan must remain in the CAA section 111(d) plan as existing sources, and remain subject to any applicable regulatory requirements in that plan, *in addition to* being subject to regulatory requirements under CAA section 111(b). This position has been challenged by some groups as contrary to the statute, under which a source can be regulated under either 111(b) or 111(d) but not both. In addition, a source that makes heat rate improvements for 111(d) compliance, or reduces its overall generation or becomes load-following due to greater natural gas and renewable generation envisioned in EPA's 111(d) plan, will have more difficulty meeting the emission standards included in the modified and reconstructed source proposal.

[6] *Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units*, Docket No. EPA-HQ-OAR-2013-0603, 79 Fed. Reg. 34,960 (Jun. 18, 2014). See https://www.federalregister.gov/articles/2014/06/18/2014-13725/carbon-pollution-standards-for-modified-and-reconstructed-stationary-sources-electric-utility.

Comments on this rule were due to the EPA on October 16, 2014, and a final rule is anticipated in June 2015. It is not possible to evaluate the impact of these proposed standards on our resource planning until the final rule is published. In addition, these requirements, once adopted, would only apply to future changes at NSP power plants if we undertake actions meeting the definitions of modification or reconstruction.

4. GHG Emission Standards for Existing Power Plants

The June 2014 *Presidential Memorandum on Power Sector Carbon Pollution Standards* directed the EPA to issue a proposed GHG emission standard for existing power plants under CAA section 111(d) by June 1, 2014 and a final standard by June 1, 2015, and to require states to submit 111(d) implementation plans to the EPA by June 30, 2016.[7] The EPA released its proposed 111(d) rule, also termed the "Clean Power Plan," in June 2014. Comments were due December 1, 2014.[8]

Unlike the new source rule under 111(b), section 111(d) of the CAA does not give the EPA authority to impose a uniform national emission performance standard for existing power plants. Rather, the statute directs the EPA to create a procedure for states to establish performance standards and to design state plans to achieve emission reduction goals. The EPA retains "backstop" authority to enforce state plans if states fail to do so and to impose a Federal Implementation Plan if a state fails to submit an acceptable plan. The proposed rule has two main components:

- CO_2 intensity goals for each state, based on EPA's view of the Best System of Emission Reduction (BSER) for that state's power sector; and
- Guidance to states for drafting plans to implement the rule.

The proposed rule includes CO_2 emission rate goals (lb CO_2/MWh) for each state that must be achieved across the electricity system in the state, including an Interim Goal to be achieved on average over the years 2020-2029 and a Final Goal to be achieved in the year 2030 and thereafter. Rather than employing a traditional CAA approach based on emission controls that can be implemented at individual power plants or "inside the fence line," the EPA has proposed goals based on a BSER that is applied to the electricity system statewide, including both regulated power plants ("affected EGUs" in the rule) and activities outside the EPA's CAA jurisdiction such

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[7] See http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

[8] *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, 79 Fed. Reg. 34,830 (June 18, 2014). Also titled the "Clean Power Plan" by the EPA. See http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule.

as renewable and nuclear energy, energy efficiency, and the re-dispatch of generation from higher to lower CO_2-emitting facilities. The EPA's authority to include these "beyond the fence line" activities in its BSER has been questioned, and will likely be one of several areas of legal challenge once the final rule is published.

The rule calculates the state goals by beginning with 2012 emissions and generation from fossil generating units within the state, then sequentially applying the following four emissions reduction "building blocks:"

1. Improving coal plant efficiency (heat rate) by 6 percent;
2. Increasing utilization of natural gas combined cycle plants to a 70 percent capacity factor, displacing generation from coal and oil/gas steam units;
3. Increasing renewable energy and maintaining nuclear plants; and
4. Expanding DSM and energy efficiency measures based on national "best practice" levels.

The resulting lbs CO_2/MWh rate, with all four building blocks, is calculated as:

$$\frac{\text{2012 FOSSIL EMISSIONS}}{\text{(COAL+NGCC+RENEWABLE+NUCLEAR) GENERATION+DSM}} = \text{STATE GOAL}$$

This goal, or its equivalent in mass terms, must be met at the statewide level, on average from 2020-2029 (for the Interim Goal) and by 2030 (for the Final Goal). The EPA's goal-setting method creates a wide disparity in reduction requirements — from 11 percent to 72 percent below the 2012 emission rate calculated by the EPA — across the country. Table 1 below shows the interim and final goals for the states in which the Company operates.

Table 1: Interim and Final Goals for NSP System States in the EPA's Proposed 111(d) Rule

State	2012 rate (lbs CO_2/MWh)	Interim Goal (lbs CO_2/MWh)	Final Goal (lbs CO_2/MWh)	Reduction from 2012 rate (%)
MN	1,470	911	873	41
WI	1,827	1,281	1,203	30
ND	1,994	1,817	1,783	11
SD	1,135	800	741	35
MI	1,690	1,227	1,161	31

The proposed rule requires states to propose to the EPA plans for achieving their emission reduction goals. States are provided some flexibility in achieving these goals. They may use:

- Different combinations of the four building blocks used in setting the goals (i.e. less of one building block compensated by more of another);
- Emission reduction measures not considered by the EPA in setting the goals, including but not limited to: transmission and distribution efficiency improvements, biomass co-firing, gas co-firing, inclusion of new NGCC units in the state's plan, CCS retrofits on existing coal plants, adding concentrating solar to the steam cycle of fossil plants, heat rate improvements on gas or oil plants, nuclear uprates, new coal or gas plants going beyond 111(b) requirements (e.g. credit for doing more CCS than required to reach 1,100 lb/MWh NSPS on new coal), CCS on new gas plants, energy storage reducing the amount of fossil generation needed to balance intermittent renewables, industrial CHP, and possibly out-of-sector GHG offsets;[9]
- The option to convert the rate-based goals into a statewide mass budget;
- The option to take a multi-state or regional approach, collaborating with other states to design a compliance plan that achieves the rate- or mass-based targets across participating states; and/or

[9] The proposed rule is ambiguous whether out-of-sector GHG offsets would be allowed to be included in state plans. Offsets may be allowed as long as a state can still demonstrate the required level of reductions from affected EGUs.

- The option to implement cap-and-trade or carbon-pricing programs, or other types of trading.

Any CO_2 reduction measures are approvable as long as they achieve the required emission reductions by the required date; create enforceable limits for affected EGUs; and are quantifiable, enforceable, and non-duplicative (i.e. avoid double-counting of emission reductions).

State plans are due to the EPA by June 2016; states may apply for a one-year extension to June 2017 or a two-year extension to June 2018 if they are collaborating on a multi-state implementation plan. The EPA aims to approve state plans within one year after receiving them. Compliance would effectively begin in 2020 (with the first required report due in 2022, on the 2020 results). The Interim Goals are binding and states must show that they are on track to meet the Interim Goal on average by 2029. From the year 2030 and on, compliance is demonstrated based on a rolling three-year timeframe.

Table 2 below summarizes the anticipated timeline of GHG rules. Note that litigation could delay the timelines below.

Table 2: Estimated GHG Regulatory Timeline

Action	Timeline
EPA finalizes new source GHG rule	January 2015
EPA finalizes modified/existing source GHG rule	June 2015
EPA finalizes existing source GHG rule	June 2015
Existing source rule state plans submitted to EPA	June 2016 – June 2018
EPA approval of existing source rule state plans	One year after submission
Compliance begins	2020
Reporting begins	2022
Final Goal must be achieved	2030 on, with 3-year rolling compliance reporting

5. Implications of GHG Regulations for Resource Planning

At the time of submitting this Resource Plan, uncertainty remains about the final form of the three EPA rules (for new, modified/reconstructed, and existing sources) described above. The new and modified/ reconstructed source rules are expected to have less overall impact on the Company's plans – since we do not expect to build new coal-fired power plants, expect any new natural gas combined cycle plant we build to meet the proposed NSPS for such units, and are not aware of any planned projects on our system that would trigger the modification/ reconstruction definitions. However the existing source rule, and our states' implementation plans, will have significant impacts on our system and at this time we do not know:

- What the final rule may entail, which could include different Interim and Final goals for our states, due to both technical corrections that have been identified, and better recognition of early action that the Company is encouraging the EPA to provide.
- The form that state plans will take in the NSP system's five states; specifically, whether these plans will be based only on direct emission limits for affected EGUs, in effect assigning the full compliance obligation to the owner/operators of these EGUs, or if they will adopt what the EPA has termed a state-driven or utility-driven portfolio approach, both of which would assign a portion of the compliance obligation to affected entities other than EGU owner/operators.
- Whether our states will prepare state-only compliance plans or collaborate with any other states within or outside the NSP system.
- Whether our states will implement rate-based plans, planning and measuring compliance against the lb CO_2/MWh goals in the final rule, or instead exercise their option to convert these goals to mass budgets (total tons of CO_2 per year).
- How much of the emission reduction obligation the states must achieve will be assigned to the Company and how much to other utilities in the state.

These "known unknowns" make it difficult to predict how the final rule and state 111(d) plans will affect our system over the resource planning period. However, unless the final rule is dramatically different from the proposal, we expect that the Company will face pressure to continue our downward carbon trajectory, while at the same time facing challenges for our fossil resources, affordability, and maintenance of fuel diversity. These expectations are a key driver of the Preferred Plan we are proposing. In particular, our Preferred Plan is guided by the following factors:

- ***The need to be proactive.*** Because of the long planning periods typical of the utility industry, we need to act early and make decisions about our resources despite the fact that GHG regulation remains in flux. We are proposing a proactive plan that will achieve significant carbon reductions while maintaining a diverse generation portfolio and avoiding premature retirement of facilities.
- ***There is no single silver bullet.*** The Company must rely on a diverse portfolio of resources to bridge the gap to a clean energy future. Integrated transmission planning will be a critical component of this strategy because it

can link utility customers to distant renewable energy resources. New gas supply infrastructure will also be key, to the extent 111(d) compliance is achieved through increased utilization of existing and construction of new gas plants.

- ***Flexibility is key.*** As energy generation, transmission, distribution, and storage technologies evolve, we must have the flexibility to adjust our strategies. Further investment in research, development and deployment will be needed to meet the challenges of the new energy landscape. Fundamental changes in the utility regulatory structure may also take place.

B. Particulate Matter, Oxides of Nitrogen and Sulfur Dioxide Emissions

Particulate matter (PM, including "coarse" PM under 10 micrometers in diameter (PM_{10}) and "fine" PM under 2.5 micrometers ($PM_{2.5}$)), nitrogen dioxide (NO_2) and sulfur dioxide (SO_2) are three of the six "criteria pollutants" regulated by the EPA under the CAA. These pollutants are regulated under three primary programs: National Ambient Air Quality Standards (NAAQS), CAA programs that address interstate transport of air pollution, and CAA programs that address visibility impairment in national parks and wilderness areas. Each of these is addressed in turn.

1. National Ambient Air Quality Standards

The CAA requires the EPA to set NAAQS to protect public health and the environment. NAAQS include both (1) primary standards to protect public health, including the health of sensitive populations, such as asthmatics, children and the elderly, and (2) secondary standards to protect public welfare, including protection against damages to animals, crops and buildings. The EPA has established NAAQS for six criteria pollutants: PM, NO_2, SO_2, ozone (O_3), carbon monoxide (CO), and lead (Pb). The EPA is required to review the NAAQS every five years and revise them as appropriate to protect public health and welfare. The NAAQS program has been in place since the early 1970s.

Once the EPA adopts or revises a NAAQS, states have two years to monitor their air, analyze the data and submit to the EPA their classification of the state into Attainment Areas (areas having monitored ambient air quality concentrations below the NAAQS), Nonattainment Areas (areas having monitored ambient air quality concentrations above the NAAQS), and unclassifiable areas. The EPA reviews the state's submittal and determines the final area designations a year later. When the EPA designates an area as Nonattainment, the state is generally given three years to develop a new State Implementation Plan (SIP) which identifies actions to be taken to bring the area back into Attainment. A SIP must include emission reduction requirements needed to demonstrate that air quality will attain the NAAQS in the timelines required by the CAA – usually within two to seven years after the SIP is submitted to the EPA for approval. Since the NAAQS are individually reviewed and revised for each pollutant, the descriptions below show the timelines that apply to current and upcoming NAAQS revisions by pollutant.

a. Coarse Particulate Matter (PM_{10}) and Fine Particulate Matter ($PM_{2.5}$)

On January 15, 2013, the EPA finalized NAAQS for both PM_{10} and $PM_{2.5}$. The EPA lowered the primary (health-based) NAAQS for annual $PM_{2.5}$ from 15 to 12 $\mu g/m^3$, and retained the established 24-hour $PM_{2.5}$ standard, which was set at 35 $\mu g/m^3$ in 2006. The EPA also retained the existing standards for PM_{10}.[10]

The EPA established the following timeline for implementation of the new $PM_{2.5}$ NAAQS in Minnesota:

Table 3: Estimated PM Regulatory Timeline

Action	Timeline
EPA finalizes revised particle NAAQS	January 2013
MPCA submits designation recommendations to the EPA	2014
EPA designates areas as Attainment, Nonattainment or Unclassifiable	2015
State Implementation Plans due to the EPA	2018
Attainment Date (5-10 years after Nonattainment designation)	2020-2025

Current monitored air concentrations of $PM_{2.5}$ in Minnesota are below both the 24-hour and the annual primary standard. In 2010, two $PM_{2.5}$ monitors in Saint Paul recorded values that would have exceeded the 2013 24-hour standard. In recent years, 24-hour $PM_{2.5}$ levels have returned to compliant levels. The 2010 exceedances, however, indicate a possible risk for future nonattainment with the $PM_{2.5}$ NAAQS.

The EPA has projected that Minnesota would remain in Attainment for the new annual standard for $PM_{2.5}$. In December 2013, the MPCA submitted its air quality data to the EPA and asked that all areas of Minnesota be designated as in Attainment of the new annual standard. In August 2014, the EPA issued its proposed designations,

[10] The EPA established the $PM_{2.5}$ NAAQS in 1997. In 2006, the EPA lowered the daily $PM_{2.5}$ standard from 65 $\mu g/m^3$ to 35 $\mu g/m^3$.

which did not include any Nonattainment areas in the states in which NSP operates. In December 2014, the EPA finalized those designations and did not classify any areas as Nonattainment in any of NSP's five states.[11] If areas were to be designated as Nonattainment for $PM_{2.5}$ at some point in the future, this could require SO_2 and/or NO_x emission reductions from our thermal generation units as these pollutants are precursors to $PM_{2.5}$.

Every five years, the EPA reviews the scientific data on health effects and decides whether any revision to the PM NAAQS is needed. It is not known what adjustments to the PM NAAQS, if any, the EPA may make after its next review cycle, which will occur in the 2018-19 timeframe. If the NAAQS were to be made more stringent, and if part of Minnesota were to become Nonattainment for the NAAQS, the MPCA would conduct a SIP planning process to assess Minnesota's air quality, evaluate emission reduction options and impose appropriate emission reduction requirements on similar time intervals as shown in Table 3 above for the 2013 standards, but starting in 2018 with final compliance in the 2025-2030 timeframe.

b. Ozone (O_3)

Ozone (also called smog) is formed from the reaction of oxides of nitrogen (NO_x) and volatile organic compounds (VOCs) in the presence of sunlight. Ozone levels are highest in the summer months. In 2008, the EPA finalized the current NAAQS for ozone, which is more stringent than the previous ozone NAAQS that was adopted in 1997. The primary NAAQS for ozone is an eight-hour standard of 75 parts per billion (ppb). The EPA has designated all of Minnesota as in attainment of the 2008 ozone NAAQS.

In April 2014, the U.S. District Court for the Northern District of California issued an order directing the EPA to propose a revised NAAQS for ozone by December 1, 2014, and to issue a final rule by October 1, 2015. The EPA released its proposed Ozone NAAQS on November 25, 2014, proposing to set both the primary (public health) and secondary (public welfare) standards as 8-hour standards within a range of 65 to 70 ppb. The EPA is seeking comment on levels for the primary standard as low as 60 ppb.

We estimate that the regulatory process to implement a new standard in Minnesota will develop on the following schedule:

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[11] See all designated Nonattainment areas at http://www.epa.gov/pmdesignations/2012standards/regs.htm.

Table 4: Estimated Ozone Regulatory Timeline

Action	Timeline
EPA proposes new ozone NAAQS	Late 2014
EPA finalizes new ozone NAAQS	October 2015
MPCA submits designation recommendations to the EPA	2016
EPA designates areas as Attainment, Nonattainment or Unclassifiable	2017
State Implementation Plans due to the EPA	2019-2020
Attainment Date (5-10 years after nonattainment designation)	2022-2027

Depending upon the level of the final standard, portions of Minnesota may not be in Attainment with the standard. For example, based on current monitoring data, all of Minnesota would be expected to attain an ozone standard of 70 ppb, but areas near the Twin Cities may not attain a standard of 65 ppb, and areas throughout the state may not attain a standard of 60 ppb.[12] If part of Minnesota is designated Nonattainment for ozone, the MPCA would be required to develop a SIP to achieve further emissions reductions of compounds that contribute to ozone formation on the approximate timeline shown above. Such a SIP would consider reductions needed and possible from many different sources of ozone precursors. The largest sources of NO_x in Minnesota today are mobile and non-point sources, and NO_x emissions from point sources have declined by 49 percent from 2000 to 2010.[13] Thus an ozone SIP may focus primarily on reducing NO_x emissions from mobile and non-point sources, but installation of additional NO_x controls at our fossil power plants might be required. It is also possible that Minnesota can avoid Nonattainment for ozone, resulting in no requirement for additional controls.

c. Nitrogen Dioxide (NO_2)

In 2010, the EPA finalized a revised primary NO_2 NAAQS. The EPA retained the existing annual average NO_2 NAAQS of 53 ppb, and set a new one-hour standard of 100 ppb. Currently, all Minnesota sites meet the annual and one-hour NO_2 NAAQS. The EPA completed area designations in early 2012, finding no area in the country to be in Nonattainment. The MPCA reported that in 2011, monitors showed concentrations in Minnesota at levels less than half of the levels allowed by the NO_2 NAAQS.

[12] *Ozone in Minnesota: 2014 Proposed Revision to Federal Ozone Standard*. Presentation to the Metropolitan Energy Policy Coalition. Frank Kohlasch, MPCA, December 4, 2014.
[13] See MPCA, January 2013: *Air Quality in Minnesota: 2013 Report to the Legislature*. Available at http://www.pca.state.mn.us/index.php/about-mpca/legislative-resources/legislative-reports/air-quality-in-minnesota-reports-to-the-legislature.html.

NO_2 concentrations near roads are usually higher than at other locations due to mobile sources. To take this into account, the new NO_2 NAAQS changed the requirements for state ambient air monitoring networks. The EPA recently established a phased schedule for states to amend their monitoring network plans to include near-road monitors, requiring them to be operational starting in the years between 2014 and 2017. The first near-road monitor is already in operation by the MPCA and the second is expected to be operational January 2015. While current monitoring data shows concentrations of NO_2 in Minnesota at 46 percent of the NAAQS,[14] we anticipate that the near-road monitors will show higher levels of NO_2 than previously monitored due to mobile source emissions. These higher NO_2 levels may lead to Nonattainment with the NAAQS. The regulatory process to address Nonattainment, if any, would develop on approximately the following schedule:

Table 5: Estimated NO_2 Regulatory Timeline

Action	Timeline
New NO_2 roadway monitoring begins	2014-2017
EPA issues Nonattainment Redesignations	2017-2018
State Implementation Plans due to the EPA	2020
Attainment Date (5-10 years after date of Nonattainment)	2022-2027

If Minnesota cannot attain the NO_2 standard, the MPCA would need to develop a SIP to address the nonattainment. It is not clear what strategy the MPCA would take in this situation, since roadway monitors would record emissions mostly from mobile sources. The MPCA's 2013 report shows a 49 percent reduction in point source NO_2 emissions from 2000 to 2010, indicating that point sources, such as power plants, are not the primary contributors to any elevated concentrations at a near-road monitoring site.[15] We believe that the MPCA would be more likely to target mobile sources for reductions if Nonattainment is based on results from a near-road monitor.

d. Sulfur Dioxide (SO_2)

The EPA last revised the primary SO_2 NAAQS in 2010, setting a one-hour standard of 75 ppb and a three-hour standard of 0.5 ppm. Minnesota is currently in Attainment with both of the SO_2 NAAQS, with levels at 32 percent of the standard, and SO_2 emissions from point sources have declined by 44 percent from 2000 to 2010.[16] The

[14] MPCA, January 2013: *Air Quality in Minnesota: 2013 Report to the Legislature*, page 4.
[15] MPCA, January 2013: *Air Quality in Minnesota: 2013 Report to the Legislature*, page 3.
[16] MPCA, January 2013: *Air Quality in Minnesota: 2013 Report to the Legislature*, pages 3-4.

EPA made its final designations for areas not attaining the SO_2 NAAQS in 2013, and did not include any areas in Minnesota.

We do not anticipate requirements for additional controls at our power plants due to SO_2 emissions. SO_2 scrubbers are already installed on all NSP system coal plants, and gas plants emit SO_2 at extremely low rates. If any new requirements were imposed, it would be expected that these would be aimed at additional ways to optimize the existing scrubbers on our coal units, if any exist.

e. Carbon Monoxide (CO)

The EPA completed its review of the primary CO NAAQS and in 2011 published its final determination to maintain the existing eight-hour standard at 9 ppm and the one-hour standard at 35 ppm. Minnesota is currently in Attainment with the carbon monoxide NAAQS. We do not foresee that status changing in the near future.

f. Lead

In 2008, the EPA finalized a new NAAQS for lead that made the standard substantially more stringent at 0.15 $\mu g/m^3$ (rolling three-month average). With the exception of a monitoring site located near Gopher Resource Corporation's lead recycling facility in Eagan, existing lead monitoring sites within Minnesota meet the lead NAAQS. Between 2000 and 2010, point source lead emissions dropped by 71 percent in Minnesota.[17] We do not foresee any further areas of Nonattainment in Minnesota in the near future.

g. Implications of NAAQS Regulatory Developments

The revisions to all six NAAQS were finalized between 2008 and 2012 to reflect the latest scientific information about the health effects of these air pollutants. Despite several NAAQS being significantly tightened, there are at present no Nonattainment areas in the state of Minnesota that might result in SIP emission reduction requirements being imposed. The next possibility that SO_2 or NO_x emission reductions might be required would be if Minnesota has areas that do not meet a new ozone NAAQS set at the lower end of EPA's proposed 65-70 ppb range, or at some future time becomes Nonattainment for $PM_{2.5}$. According to the NAAQS implementation schedules shown in the tables above, further reductions might be

[17] MPCA, January 2013: *Air Quality in Minnesota: 2013 Report to the Legislature*, page 3.

required to be achieved in the early to mid 2020s, but only if Minnesota enters Nonattainment for ozone or particulate matter.

If areas of the state are classified Nonattainment with any of the NAAQS, this would tend to affect state planning more than utility resource planning. When developing the SIP to address Nonattainment, the MPCA would need to address point source emissions inside of the Nonattainment area, mobile source emissions inside of the Nonattainment area, area and residential source emissions inside of the Nonattainment area, and transport of air pollution across state boundaries.

The MPCA in their 2013 report to the Minnesota Legislature stated,

> *The majority of air pollutants of most concern today come from smaller wide-spread sources that are not regulated in the way power plants and factories are. These non-point sources include cars, trucks, construction equipment, residential wood burning, and residential garbage burning. The current regulatory structure will not help much with pollution from these sources.*[18]

This statement suggests that while further emissions reductions from larger point sources such as power plants are possible, the primary focus is likely to be on numerous small sources in order to achieve the needed emission reductions to address the causes of Nonattainment if it should occur.

If our system were to be impacted by future Nonattainment, it already is equipped with much of the pollution control equipment that could be required. With the retirement of Black Dog Units 3 and 4 in early 2015, our remaining coal plants are all equipped with scrubbers to control SO_2 emissions as well as baghouses to control PM emissions. All three Sherco units are equipped with NO_x combustion controls that have significantly reduced NO_x emissions from the units. The King plant and our combined cycle gas plants are also equipped with Selective Catalytic Reduction (SCR) technology to control NOx emissions.

The only additional control equipment that could be required would be SCR technology to further reduce NO_x emissions from one or more of the Sherco units. Given the NAAQS timetables shown in the tables above, SCR installation could be required, if at all, at the earliest in the early to mid-2020's. Depending on where the ozone NAAQS standard is set, it is also possible that Minnesota could remain in Attainment for ozone (requiring no additional NO_x controls), or that Minnesota could be in Nonattainment but emission reductions would be required from other sectors.

[18] MPCA, January 2013: *Air Quality in Minnesota: 2013 Report to the Legislature*, Summary page 2.

2. *Interstate Transport of Air Pollution*

The CAA also requires that NAAQS SIPs include provisions that prevent sources within a state "from emitting any air pollutant in amounts which will … contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any" NAAQS.[19] The EPA has developed programs for the Eastern U.S. that would reduce interstate transport of pollutants that are precursors to ozone and fine particles. Oxides of nitrogen are a precursor to ozone and fine particle formation, while SO_2 is a precursor to fine particle formation. For the utility industry, the current program is the Cross-State Air Pollution Rule (CSAPR).

CSAPR was designed as a "cap-and-trade" program that reduces overall emissions from EGUs. This means that total emissions from EGUs in a state or region are limited (the cap), and each ton of emissions allowed is represented by an emission allowance that can be transferred among EGUs (the trade). A cap-and-trade program thus reduces total emissions to the capped amount, but provides flexibility for EGUs to meet their individual emission reduction requirements through installation of control equipment, purchase of emission allowances from other EGUs, or a combination of both.

Depending on the EPA's analysis of an upwind state's contribution to Nonattainment in downwind states, CSAPR imposes one or both of the following emission limitations: (1) summer season NO_x emissions (to address ozone), and/or (2) annual NO_x and SO_2 emissions (to address fine particles). In Minnesota's case, the impact of concern has been fine particle Nonattainment areas in downwind states, rather than ozone. The CSAPR applies to Minnesota for fine particle precursors, requiring reductions in annual NO_x and SO_2 emissions starting in 2015.

There has been significant litigation related to CSAPR. In December 2011, the D.C. Circuit stayed the effectiveness of CSAPR and instructed the EPA to continue administering a predecessor rule (the Clean Air Interstate Rule, CAIR) pending the court's resolution of the appeals filed against the CSAPR. In August 2012, the U.S. Circuit Court of Appeals for the D.C. Circuit issued an opinion finding the CSAPR to contradict the CAA, vacated it, and instructed the EPA to continue administering the CAIR pending adoption of a valid replacement.

[19] CAA, 42 U.S.C. section 7410(a)(2)(D)(i)(I).

In April 2014, the U.S. Supreme Court reversed and remanded the case to the D.C. Circuit. The Supreme Court held that the EPA's design of CSAPR did not violate the CAA, and that states had received adequate opportunity to develop their own plans. Because the D.C. Circuit overturned the CSAPR on two over-arching issues, there are many other issues the D.C. Circuit did not rule on that will now need to be considered on remand.[20]

In October 2014, the D.C. Circuit granted an EPA motion to lift its stay of CSAPR.[21] The CSAPR Phase I requirements (which would have started in 2012 without the stay) will now apply in 2015 and 2016.[22] These requirements replace the CAIR requirements that have applied to NSP-Wisconsin in the past. While there is a Phase II of the CSAPR program that would start in 2017, the Minnesota and Wisconsin Phase II emission limitations are either the same as those in Phase I (Minnesota) or only slightly lower (Wisconsin).

NSP-Minnesota can operate within its CSAPR emission allowance allocations without installation of additional controls, particularly given the cessation of coal operations at Black Dog Units 3 and 4 in early 2015. NSP-Wisconsin can operate within its CSAPR emission allowance allocation for SO_2 due to cessation of coal combustion at Bay Front Unit 5. NSP-Wisconsin anticipates compliance with the CSAPR for NO_x in 2015 through operational changes or allowance purchases. NSP-Wisconsin's compliance with CSAPR will not require significantly different actions than what NSP-Wisconsin has been doing since 2009 to comply with CAIR.

3. *Visibility Impairment in National Parks and Wilderness Areas*

Visibility impairment is caused when sunlight encounters pollution particles in the air. Some light is absorbed and other light is scattered before it reaches an observer, reducing the clarity and color of what the observer sees. In 1977, the CAA established a national goal of remedying existing and preventing future visibility impairment from man-made air pollution in specified "Class I" areas – national parks and wilderness

[20] NSP-Minnesota appealed the CSAPR, seeking the allocation of additional emission allowances for NSP-Minnesota. NSP-Minnesota contended that the EPA's method of allocating allowances arbitrarily resulted in fewer allowances for its Riverside and High Bridge plants than should have been awarded to reflect their operations during the baseline period, which included coal-fired operations prior to the conversion of these plants to natural gas. NSP-Minnesota also requested that EPA reconsider and amend the CSAPR to address this issue. Because of the court's overall ruling on CSAPR, these issues have not yet been addressed.

[21] See http://www.epa.gov/airmarkets/airtransport/CSAPR/pdfs/CSAPR_Stay_Lift.pdf

[22] See http://www.epa.gov/crossstaterule/pdfs/CSAPRinterimfinal11_12_14.pdf

areas throughout the United States, including the Boundary Waters Canoe Area and Voyageurs National Park in Minnesota.

The EPA has taken a two-phased approach to implement this program. The first phase, "reasonably attributable visibility impairment" (RAVI), was implemented in the 1980s to address visibility impairment reasonably attributable to a specific source. The EPA adopted regulations for this program designed to address plume blight, defined as "smoke, dust, colored gas plumes, or layered haze emitted from stacks which obscure the sky or horizon and are relatable to a single source or a small group of sources."

The second phase was designed to address widespread, regionally homogeneous haze that results from emissions from a multitude of sources. In 1999, the EPA adopted its Regional Haze Rule (RHR) to address this type of visibility impairment. State environmental agencies are required to submit SIPs that develop and implement their strategy to reduce emissions that may contribute to regional haze. RHR SIPs also must include reasonable progress goals and periodic evaluation/revision cycles designed to make appropriate progress toward the national goal of no man-made visibility impairment in Class I areas by 2064. These SIPs focus on emissions of SO_2, NO_x and particulate matter, and must be revised approximately every ten years to continue reasonable progress toward reaching the 2064 national goal.

a. Implementation of the Regional Haze Program in Minnesota

The MPCA began developing the Minnesota Regional Haze SIP after the EPA issued its final Best Available Retrofit Technology (BART) Guidelines in 2005. BART applies to major emission sources that were placed into operation between 1962 and 1977, if they are found to reasonably contribute to visibility impairment in one or more Class I areas. In this initial round of Regional Haze SIP development, the MPCA was required to identify sources subject to BART requirements and determine what constitutes BART for each source. A "BART Determination" is a case-by-case analysis that "take[s] into consideration the costs of compliance, the energy and non-air quality environmental impacts of compliance, any existing pollution control technology in use at the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."[23] The MPCA identified multiple units in the utility and taconite industries as "subject to BART," including Sherco Units 1 and 2.

[23] CAA, 42 U.S.C. section 7491(g)(2).

In December 2009, the MPCA approved the Regional Haze SIP for Minnesota, which included the BART determination for Sherco Units 1 and 2. The MPCA's BART controls for Sherco Units 1 and 2 consisted of combustion controls to reduce NO_x (Over-Fire Air (OFA), combustion controls and Low-NO_x burners) and scrubber upgrades to reduce SO_2. The MPCA concluded that SCR should not be required because the minor additional visibility benefits do not outweigh the substantial additional costs.[24] The installation of the combustion controls on Sherco Units 1 and 2 was completed several years ago, and currently their operation is being fine-tuned. The scrubber upgrades are underway and are scheduled to be complete by 2015. The MPCA submitted this Regional Haze SIP to EPA for review and approval.

Following its adoption of CSAPR in 2011, the EPA determined that the requirements of the CSAPR satisfy the requirements for an approvable "BART Alternative" under the RHR. This rule allows states subject to CSAPR to utilize compliance with CSAPR in lieu of source-specific BART emission limits for EGUs. In April 2012, the MPCA approved a supplement to its 2009 Regional Haze SIP, finding that the CSAPR meets BART for EGUs in Minnesota. The supplement also included an Administrative Order that established source-specific BART emission limits for Sherco Units 1 and 2 that reflected the MPCA's 2009 determination. In June 2012, the EPA issued its final approval of the Minnesota Regional Haze SIP for EGUs. This included approval of the source-specific emission limits for Sherco Units 1 and 2 as strengthening the SIP, but EPA avoided characterizing them as BART limits.

The MPCA is required to make its five-year progress report on implementation of the Regional Haze SIP in 2014. The MPCA has issued its draft report, which states that it expects to meet its 2018 goals and that no further changes are needed before the MPCA is scheduled to next revise its plan in 2018. The MPCA also documented that point source SO_2 and NOx emissions from facilities such as power plants and other industrial sources have already been reduced beyond the goals set for 2018 in the 2009 SIP.[25]

The MPCA will also be required to revise its SIP by 2018 to consider additional emission reductions that may be necessary to maintain reasonable progress toward achievement of the national visibility goal by 2064. In this SIP revision, the MPCA would be anticipated to consider whether additional control technology should be required for the Sherco plant, as well as on multiple other sources of emissions in Minnesota.

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[24] *Regional Haze State Implementation Plan*, at 899-906, MPCA (Dec. 2009).
[25] *Five-Year Regional Haze Progress Report, State Implementation Plan*, Dec. 2014, at pages 20, 22 and 33.

In August 2012, the National Parks Conservation Association, Sierra Club, Voyageurs National Park Association, Friends of the Boundary Waters Wilderness, Minnesota Center for Environmental Advocacy, and Fresh Energy appealed the EPA's approval of the Minnesota Regional Haze SIP to the U.S. Court of Appeals for the Eighth Circuit (Eighth Circuit). NSP-Minnesota and other regulated parties were denied intervention. In June 2013, the Eighth Circuit ordered this case to be held in abeyance until the U.S. Supreme Court decided the CSAPR case. In October 2014, the Eighth Circuit set a briefing schedule. The case will be briefed by early 2015. An argument date has not been set. If this litigation ultimately results in further EPA proceedings concerning the Minnesota Regional Haze SIP, such proceedings may consider whether SCR should be required for Sherco Units 1 and 2.

b. Implementation of the RAVI Program in Minnesota

Following initial adoption of the RAVI program, in 1985 the EPA began adopting federal implementation plans (FIPs) for those states that had failed to submit SIPs to implement RAVI. Since Minnesota had not a submitted a SIP, the EPA adopted a FIP for Minnesota that included general visibility requirements and long-term strategies, and determined that it was not necessary to revise the FIP for Minnesota to include BART requirements. After detailed study, the EPA made a finding in 1988 that there was no RAVI impairment in Voyageurs National Park.

However, in October 2009, the Department of the Interior (DOI) certified that a portion of the visibility impairment in Voyageurs National Park, as well as Isle Royale National Park in Michigan, is reasonably attributable to emissions from Sherco Units 1 and 2. The EPA is required to make its own determination whether there is RAVI-type impairment in these parks and examine which sources may cause or contribute to any RAVI impairment that is identified. After studying the national parks and evaluating multiple sources, if the EPA finds that Sherco Units 1 and 2 cause or contribute to RAVI in the national parks, the EPA would then evaluate whether the level of controls required by the MPCA is appropriate. The EPA has said that it plans to issue a separate notice on the issue of BART for Sherco Units 1 and 2 under the RAVI program.

In December 2012, a lawsuit against the EPA was filed in the U.S. District Court for the District of Minnesota by the National Parks Conservation Association, Minnesota Center for Environmental Advocacy, Friends of the Boundary Waters Wilderness, Voyageurs National Park Association, Fresh Energy, and Sierra Club. The lawsuit alleges that the EPA has failed to perform a nondiscretionary duty to determine

BART for the Sherco Units 1 and 2 under the RAVI program. The EPA filed an answer denying the allegations. The District Court denied NSP-Minnesota's motion to intervene. NSP-Minnesota appealed this decision to the Eighth Circuit, which on July 23, 2014, reversed the District Court decision and found that NSP-Minnesota has standing and a right to intervene.

In June 2014, the EPA and the plaintiffs lodged a draft consent decree with the District Court. If entered, the consent decree would establish a schedule whereby the EPA would issue a proposal on February 27, 2015, determining whether visibility impairment in the national parks is reasonably attributable to Sherco Units 1 and 2. If the EPA determines that it is, the consent decree would require the EPA to make a final RAVI BART determination for these units by August 31, 2015. If the EPA determines that it is not, the EPA would not determine BART for Sherco Units 1 and 2. NSP-Minnesota filed comments opposing the proposed consent decree and will object to its entry given NSP-Minnesota's right to intervene in the litigation and thus participate in the negotiation of any purported settlement of the case.[26]

c. Implications of Visibility Program Regulatory Developments

The RAVI and Regional Haze programs focus on reducing emissions of PM, SO_2 and NO_x as pollutants that can result in visibility impairment. Based on the current level of controls for PM and the upgraded controls for SO_2 at Sherco Units 1 and 2, it is not expected that any further reductions would be required due to implementation of visibility programs. For NO_x, SCR on one or both units could be required to obtain further emission reductions.

If the litigation on Regional Haze results in new revisions to Minnesota's Regional Haze SIP, the currently selected controls for Sherco Units 1 and 2 might continue to be required, or the BART determination might be revised to include SCR on one or both units. If the litigation on RAVI results in a new BART determination process for Sherco Units 1 and 2, the currently selected controls for Sherco Units 1 and 2 might

[26] NSP-Minnesota disputes the contention that emissions from Sherco Units 1 and 2 are having a direct RAVI-type impact on the national parks. Sherco Units 1 and 2 were among numerous units found subject to BART under the Regional Haze program, which is meant to reduce haze that results from the combined emissions of a large number of sources over a broad regional geographic area. RAVI-type impacts are distinct from regional haze. Complex tracer studies and visibility impairment event back trajectory analyses are necessary to determine if any individual source in Minnesota, including multiple sources far closer to the national parks, might have this uncommon impact.

continue to be required, or the BART determination might be revised to include SCR on one or both units.

The timeframe in which SCR might be required is expected to be 2020-2022 at the earliest, but likely later. This time estimate would pertain if the EPA: (1) commenced a RAVI proceeding in 2015-2016, and determined a new BART for Sherco Units 1 and 2 without performing the required studies to first test whether the units have a RAVI-type impact, or (2) evaluated the Minnesota Regional Haze SIP in 2015-2016 if the Eighth Circuit reverses the EPA's approval of the Minnesota Haze SIP, disapproves the MPCA's BART determination, and requires SCR. Sources are generally given up to five years to complete installation of controls after they are required, so if one or both units require SCRs, they would need to be installed and operating by 2020-2022 at the earliest.

If SCR is not required as an outcome of the litigation as described above, but is required as part of the 2018 revisions to the Minnesota Regional Haze SIP, the timeframe for installation and operation would be the mid-2020s, since the five-year timeline starts when the EPA approves the SIP, which usually takes at least two years after the state submits a SIP. Further controls on emission units in the state would be considered as part of each succeeding revision to the MPCA's Regional Haze SIP.

Since BART applies only to major emission sources that were placed into operation between 1962 and 1977, Sherco Unit 3 is not subject to BART; however, this unit would be considered in the MPCA's 2018 revision to the Regional Haze SIP.

Our system already is equipped with almost all of the pollution control equipment that could be required in future regional haze planning cycles. With the retirement of Black Dog Units 3 and 4 in early 2015, our remaining coal plants all have scrubbers installed to control SO_2 emissions and have baghouses to control PM emissions. All three Sherco units are equipped with NO_x combustion controls that have significantly reduced NO_x emissions from the units. The King plant and our combined cycle gas plants are also equipped with SCR technology to control NO_x emissions.

4. *Potential Requirements for SCR at Sherco Units 1 and 2*

As explained above, while the emissions of oxides of nitrogen from Sherco Units 1 and 2 are currently in compliance with all applicable environmental regulations through the controls (low-NO_x burners and over-fire air) currently installed on those units, there are as-yet-unknown regulatory and legal developments that could require further reduction in NO_x emissions in the future. One option to reduce NO_x

emissions would be the installation of selective catalytic reduction (SCR). However, all of these potential developments are subject to uncertainty, making it difficult to predict when or if further NO_x emission reductions would be required.

- **Particulate matter**: As of December 2014, the EPA has finalized its area designations for the 2012 $PM_{2.5}$ NAAQS, and did not classify Nonattainment areas in any of NSP's five states. Therefore an SCR mandate driven by $PM_{2.5}$ concentrations is unlikely.
- **Ozone**: The EPA released its proposed ozone NAAQS on November 25, 2014, proposing an 8-hour standard within a range of 65 to 70 ppb. Some areas in Minnesota may not attain a standard of 65 ppb, raising the possibility we could be required to achieve further NO_x reductions at Sherco 1 and 2. However, we do not know where the EPA will set the final standard; whether areas of the state will be classified as Nonattainment; if so, whether the MPCA will seek additional power plant NO_x emission reductions or focus instead on mobile and non-point sources. We believe the earliest SCR could be required is the mid-2020s, but SCR may not be required.
- **Regional Haze**: SCR has in the past been considered as a potential BART for haze compliance; however, the MPCA in its 2009 state implementation plan concluded that SCR should not be required because the minor additional visibility benefits do not outweigh the added costs. The MPCA has made its five-year progress report, stating that it expects to meet its 2018 goals and no further changes are needed before the 2018 regional haze plan revision. There is pending litigation, on which the Eighth Circuit will rule in late 2015, which challenges the EPA's decision to approve the Minnesota plan. If the EPA's approval is reversed, the EPA may consider whether SCR should be required for Sherco Units 1 and 2. The timeframe in which SCR might be required is the mid-2020s (five years after EPA approval of the 2018 regional haze plan revision), but SCR may not be required.
- **RAVI:** There is pending litigation on whether visibility impairment in two national parks is reasonably attributable to Sherco Units 1 and 2. If the EPA determines that it is, the EPA would make a final RAVI BART determination, possibly as early as late 2015. The timeframe in which SCR might be required is 2020-2022 at the earliest, but SCRs may not be required.
- **Environmental externalities:** The Minnesota Commission recently initiated a proceeding to update the externality cost values assigned to NO_x and other pollutants (see Section III.B below). We will not know until late 2015 or early 2016 the updated value assigned to NO_x and what effect this may have on the decision to pursue further NO_x reductions.

In summary, the earliest further NO_x reductions could be required on Sherco Units 1 and 2 is 2020-2022 under RAVI or the mid-2020s under regional haze or ozone rules. However, this depends on as yet unresolved litigation and future regulations. Minnesota could remain in ozone Attainment, or could be in Nonattainment but the MPCA not require NO_x reductions from those units; the MPCA's 2018 regional haze plan revision may not find SCR to be BART for the units; a RAVI proceeding may conclude that the units do not cause a reasonably attributable visibility impairment in the national parks or, if attribution is found, may not require SCR as BART.

Considering these regulatory and legal uncertainties, we are not proposing installation of SCR on Sherco Units 1 and 2 in a specific timeframe in the Preferred Plan. In the event one of them develops in a way that makes it clear further NO_x emission reductions are required by a given year, we will consider whether SCR installation, unit retirement or another strategy is in our customers' interests, and propose the preferred strategy in a future Resource Plan.

C. Regulation of Hazardous Air Pollutant Emissions

Both state and federal regulations require reductions in Hazardous Air Pollutant emissions from power plants. In 2006, the Minnesota Legislature passed the Minnesota Mercury Emissions Reduction Act (MMERA). The MMERA provided a process for implementation and cost recovery for utility efforts to reduce mercury emissions at certain power plants, in our case the King and Sherco generating facilities. Mercury controls have already been installed and are operational on Sherco Unit 3 and at King. The Minnesota Commission has also approved installation of activated carbon injection for mercury removal on Sherco Units 1 and 2, to be operational by early 2015.

In 2012, the EPA adopted its final rule establishing National Emission Standards for Hazardous Air Pollutants for coal- and oil-fired power plants. This rule is often referred to as the Mercury and Air Toxics Standard (MATS). Coal-fired power plants must meet emission rate limits for mercury, non-mercury metals and acid gases. Particulate matter is a surrogate for non-mercury metals and sulfur dioxide is a surrogate for acid gas emissions. Plants are expected to rely upon control technologies, work practices and compliance strategies to meet these limits.

Compliance with the MATS is required by April 16, 2015 for our Sherco and King facilities. The King plant can rely upon the pollution control equipment upgrades installed during the MERP project to comply with the MATS. Sherco Unit 3 can also meet the MATS requirements utilizing existing controls. For Sherco Units 1 and 2, the

Company is in the process of improving the PM removal performance of the Wet Electrostatic Precipitators to comply with the MATS at these units. In addition, the MPCA's Regional Haze SIP required us to add sparger modules to the existing wet scrubbers to reduce SO_2 emissions, which will also reduce acid gases. Finally, the installation of activated carbon injection under MMERA controls mercury emissions. All of these technologies operating together will reduce emissions of the pollutants regulated by MATS to levels below the emission rate limits. The conversion of our Bay Front Unit 5 from coal to natural gas and the retirement of Black Dog Units 3 and 4 prior to the compliance deadline of April 16, 2015 exclude these units from MATS requirements.

On December 19, 2014, the EPA released a proposed rule containing technical corrections to the MATS rule.[27] While we are still evaluating the corrections, they appear to provide additional flexibility for some of our units without imposing additional requirements or fundamentally changing our MATS compliance strategy.

On November 25, 2014, the U.S. Supreme Court agreed to hear several petitions for review of the U.S. Court of Appeals for the D.C. Circuit's decision upholding the MATS rule. The Court will consider only whether the EPA unreasonably refused to consider costs in determining whether it is appropriate to regulate hazardous air pollutants emitted by electric utilities. Because the mercury controls at our King and Sherco plants are required by state law as well as federal law, and the controls for SO_2 and PM are already in place at these plants, we do not anticipate that the Court's decision will impact our power plants.

In 2011, the EPA adopted emission limits for hazardous air pollutants from industrial boilers (IB MACT) to regulate boilers and process heaters fueled with coal, biomass and liquid fuels. These standards apply to biomass combustion at Bay Front Units 1 and 2 as well as to several small heating boilers located at our facilities. Compliance is required by early 2016, and we expect to complete the installation of a baghouse and mercury controls at the Bay Front facility that are designed to meet the requirements of this rule by early 2015. For the small heating boilers, no upgrades are required for IB MACT compliance. The only requirements are for tuning and inspections.

D. Regulation of Coal Combustion Residuals (Ash)

Coal Combustion Residuals (CCRs), often referred to as coal ash, are currently considered exempt wastes under the federal Resource Conservation and Recovery Act

[27] See http://www.epa.gov/mats/actions.html.

(RCRA), and are regulated under state solid waste programs. Coal ash is residue from the combustion of coal in power plants. Generally, CCRs are captured by pollution control equipment and either recycled for beneficial reuse or disposed of appropriately as non-hazardous industrial waste. Environmental issues involving coal ash derive from concerns regarding structural failure of large surface impoundments (e.g. the 2008 Tennessee Valley Authority Kingston ash pond failure, and more recent incidents at Duke Energy power plants in the Southeast U.S.), allegations of inconsistent oversight by the states, and the potential for releases from unlined ash impoundments and landfills to impact drinking water sources.

Currently the CCRs that result from the combustion of coal at Sherco Units 1 and 2 are stored or disposed of wet within permitted, engineered and lined ponds as a non-hazardous industrial waste. The fly ash generated from Sherco Unit 3 is disposed of within a permitted, engineered and lined ash disposal facility located on plant property, while the bottom ash from this facility is stored with the bottom ash from Units 1 and 2 within a lined pond as a non-hazardous waste until it can be beneficially used as a construction material within the pond or properly disposed. The fly ash from the King plant is disposed of within a permitted, engineered and lined commercial disposal facility as a non-hazardous industrial waste, while the bottom ash from this facility is beneficially utilized in the manufacture of products.[28]

Xcel Energy's operations are subject to federal and state laws that impose requirements for handling, storage, treatment and disposal of wastes. On December 19, 2014, the EPA signed a final rule establishing national standards for the management and disposal of CCRs.[29] The rule regulates this material as a non-hazardous waste under Subtitle D of the RCRA. The rule establishes minimum design and operating requirements for CCR landfills and surface impoundments that are comparable to Xcel Energy's current requirements under State enforceable, site-specific permits and operating plans. While we are still evaluating the 745-page rule, a review of the EPA's own rule summary and a spot-check of key provisions of the rule reaffirm our opinion that the rule will have minimal direct impact on Xcel Energy operations or costs.

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[28] Further information on Xcel Energy's coal ash management practices can be found at http://www.xcelenergy.com/Environment/Doing_Our_Part/Compliance_Programs/Coal_Ash_Management.

[29] *Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities*. Final Rule, December 19, 2014. See http://www2.epa.gov/coalash/coal-ash-rule.

E. Water Quality Regulation

1. Cooling Water Intake Structures

Section 316(b) of the federal Clean Water Act (CWA) requires the EPA to develop regulations governing the design, maintenance and operation of cooling water intake structures to assure that these structures reflect the best technology available for minimizing adverse impacts to aquatic species. The regulations must address both impingement (the trapping of aquatic biota against plant intake screens) and entrainment (the protection of small aquatic organisms that pass through the intake screens into the plant cooling systems).

The EPA released the 316(b) rule on May 19, 2014, along with a Biological Opinion issued by the U.S. Fish and Wildlife Service (FWS) and National Marine Fisheries Service (NMFS), and published the final rule in August 2014. The rule requires companies:

- To adopt one of seven options addressing impingement of biota at the entrance to cooling water intake structures, with approval by state or federal National Pollutant Discharge Elimination System (NPDES) permit writers;
- To minimize entrainment of biota into the structures, as directed by the permit writer taking a number of factors into account;
- To implement the impingement, entrainment, and other measures as soon as practicable after the entrainment measures have been identified, with interim milestones the permit writer may set, or for new units upon commencing operations;
- To provide extensive information in permit applications, including source water physical and biological data, intake structure and system data, proposed impingement compliance methods and supporting study plans, previously conducted entrainment studies, and the operational status of the plants; and
- For plants that withdraw more than 125 million gallons per day, to provide two-year comprehensive entrainment characterization studies, technical feasibility and cost evaluation studies, benefit valuation studies, and studies of non-water quality environmental and other impacts, with peer review of the last three.

The rule does not mandate the use of closed-cycle cooling for existing facilities. However qualifying closed-cycle systems will satisfy the final rule's impingement and likely will satisfy its entrainment requirements. The definition of qualified closed-cycle cooling has been broadened to include existing impoundments of waters of the U.S., if sufficiently documented as having been designed to provide a recirculating cooling function or if built in uplands, and to delete references to specific cycles of concentration, percentage flow reduction, and continuous flow constraints.

Regarding Endangered Species Act (ESA) provisions, the final rule requires permit writers to provide copies of applications to the FWS and NMFS, so these agencies can provide input within 60 days on endangered and threatened species and critical habitat potentially affected by intake structures and recommended permit conditions. If permit writers incorporate those conditions and permittees conduct all measures recommended by the Services, the permit will provide "incidental take" authorization. The FWS/NMFS biological opinion provided with the final rule states that the final rule is not likely to jeopardize listed species or destroy or adversely modify designated critical habitat.

The definition of "existing facilities" would include nuclear uprates and other repowered and significantly modified units, even if the turbine, condenser, or fuel are replaced. However, replacement units—essentially newly built, stand-alone units constructed at existing facilities regardless of change in generation capacity, cooling water flow, or use of an existing intake structure—would be considered a "new" unit and subject to closed-cycle cooling equivalent requirements.

The final rule provides a *de minimis* exception for impingement mortality requirements for very low impingement rates, but cautions that ESA-listed species may not be taken. The rule also provides less stringent impingement standards for low-capacity utilization units.

NSP System power plants that use greater than 2 million gallons per day of surface water are required to comply with the rule: Sherco, Monticello, Riverside, High Bridge, Black Dog, King, Prairie Island, Red Wing, Wilmarth, Bay Front and French Island. Additionally, three plants may be required to reduce entrainment mortality: Monticello, King and Black Dog.

The Sherco plant is already a closed-cycle cooling facility and as such, will not likely be required to make significant cooling water intake structure upgrades to comply with the rule.

2. *Thermal Discharge*

The EPA regulates the impacts of heated cooling water discharge from power plants under CWA Section 316(a). States with authority to implement and enforce CWA programs (e.g. Minnesota, Wisconsin) have state-specific water quality criteria including thermal discharge temperature parameters to protect aquatic biota. Plants must operate in compliance with the thermal discharge temperature parameters. No changes have been made to the thermal discharge temperature parameters in Minnesota. In 2010, Wisconsin implemented new water quality standards regulating the thermal discharge temperature from facilities with state-issued NPDES permits. The new requirements are being incorporated into facility permits as the permits come due for renewal.

Our Bay Front plant in northern Wisconsin was the first Xcel Energy plant to receive new thermal discharge limits, in 2012. The new discharge limits are being implemented over a five-year period to allow the plant to determine appropriate compliance and operational options needed to achieve compliance. Modeling of the plant discharge indicates that there are challenges to meeting the new requirements for approximately nine out of twelve months each year. We are evaluating both regulatory and operational options to achieve compliance, and we anticipate that there will be some as yet undetermined impacts on plant operations and possible cost implications to achieve compliance by the five-year deadline.

French Island does not currently have to comply with the thermal rules until its existing permit is renewed sometime after 2014. Typically, facilities are given up to five years to achieve compliance. Preliminary modeling indicates that French Island will have challenges to achieve compliance during the late summer and early fall periods of the year. We are continuing to evaluate the potential impacts and possible options for compliance.

3. Effluent Limitation Guidelines

As part of the NPDES process, the EPA identifies technology-based contaminant reduction requirements called Effluent Limitation Guidelines (ELGs). The ELGs are used by permit writers as the maximum amount of a pollutant that may be discharged to a water body and apply to power plants that use coal, natural gas, oil or nuclear materials as fuel and discharge treated effluent to surface waters, as well as to utility-owned landfills that receive coal combustion residuals. ELGs are periodically updated to reflect improvements in pollution control and reduction technologies.

The EPA published a proposed ELG rule in June 2013. The EPA is currently reviewing public comments and anticipates issuing a final rule in September 2015. The revised ELGs would be implemented as each facility's NPDES permit is renewed between 2015 and 2020, with final facility compliance following five years after permit issuance.

The EPA will continue to regulate contaminants in the effluent discharged from power plants to surface waters. It is expected that some of the existing ELGs will be made more restrictive, but the extent of the reductions and the impacts to power plant operations is not estimable at this time. States that implement the federal NPDES have the authority to implement more restrictive requirements than are currently in place and it is possible that states will utilize the extensive docket of information published in the EPA proposal to justify more stringent discharge limits. Because of public comments received on the King NPDES permit, the MPCA is reviewing whether more restrictive discharge limits are necessary for the plant. A decision by the MPCA is expected sometime in 2016 at the soonest.

4. Waters of the United States

In April 2014, the EPA and the U.S. Army Corps of Engineers (USACE) issued a proposed rule to revise the regulatory definition of "waters of the United States" (WOTUS). The proposal would significantly expand the universe of land features and water bodies that are subject to CWA jurisdiction. Under the CWA, federal permitting and oversight are required for any activity having the potential to impact WOTUS. Although the plain language of the CWA limits federal jurisdiction to "navigable" waters, federal agencies have broadly interpreted that to include adjacent waters, wetlands, man-made ditches and ephemeral streams. A final rule is not anticipated before the first quarter of 2015.

Our review of the EPA's proposal indicates that the new definition would impact the Company in a number of ways by adding complexity, cost and delay to project permitting. Current operations would also be impacted by the imposition of new regulatory requirements to previously exempt on-site or adjacent water bodies or ditches. The proposed changes would:

- Increase the difficulty of siting gas pipeline and transmission line projects, since many more areas will need to be avoided or else be subject to extensive and time-consuming CWA permitting;
- Complicate certain distribution line routing/re-routing work by triggering a lengthy permitting process before work can be conducted in or near WOTUS, for example, when the Company is required to reroute our lines due to state and local highway projects;

- Complicate the process to site, permit and construct wind and solar facilities, particularly in areas that have isolated water features. Additional time and cost will be incurred to either obtain the permits or to avoid areas that would trigger the need for federal permitting; and
- Increase cost and potential reliability issues as existing facilities, especially substations, must be retrofitted with additional oil-spill prevention and containment features to prevent an oil release from reaching WOTUS.

III. MINNESOTA STATUTES AND GOALS RELATED TO CARBON DIOXIDE

A. CO_2 Regulatory Proxy Cost

Minn. Stat.§ 216H.06 required the Minnesota Public Utilities Commission to establish an estimate of the likely range of costs of future CO_2 regulation on electricity generation, and update the estimate annually following informal proceedings conducted by the Commissioners of Commerce and Pollution Control that allow interested parties to submit comments. Initial values were established in 2007 and have been updated several times subsequently.

In the latest (2014) update, following recommendations from the MPCA and the Department of Commerce (DOC), the Commission retained the range of $9 to $34 per short ton of CO_2 from previous years, finding that there is little additional certainty regarding the future costs of CO_2 regulation than existed in prior updates. The Commission decided, based on the agencies' assessment of the earliest reasonable timeframe for the forthcoming EPA GHG regulations to be in effect, that utility resource plans should apply this range of values beginning in 2019. (The EPA's GHG rule for existing power plants under CAA section 111(d), which was released subsequent to the Commission decision, proposes a first compliance year of 2020.) The Commission adopted this cost range as the annual update for both 2014 and 2015.[30]

1. *Application of Regulatory Proxy Values in this Resource Plan*

[30] ORDER ESTABLISHING 2014 AND 2015 ESTIMATE OF FUTURE CARBON DIOXIDE REGULATION COSTS. *In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minn. Stat. § 216H.06*. Docket No. E999/CI-07-1199. April 28, 2014.

We have applied the midpoint of the Commission's 2014/15 updated range, \$21.50/short ton CO_2, as a base assumption in all scenarios modeled in Strategist. We have also modeled, as sensitivities:

- The two ends of the range, \$9 and \$34/ton, starting in 2019;
- \$9 and \$34/ton starting in 2024, to represent the possibility that the first compliance year for CO_2 regulations may be delayed; and
- A \$0 value to represent the possibility that CO_2 remains unregulated, as well as to provide an indication of the imputed costs and emissions impacts of the other CO_2 price assumptions on the planning scenarios.

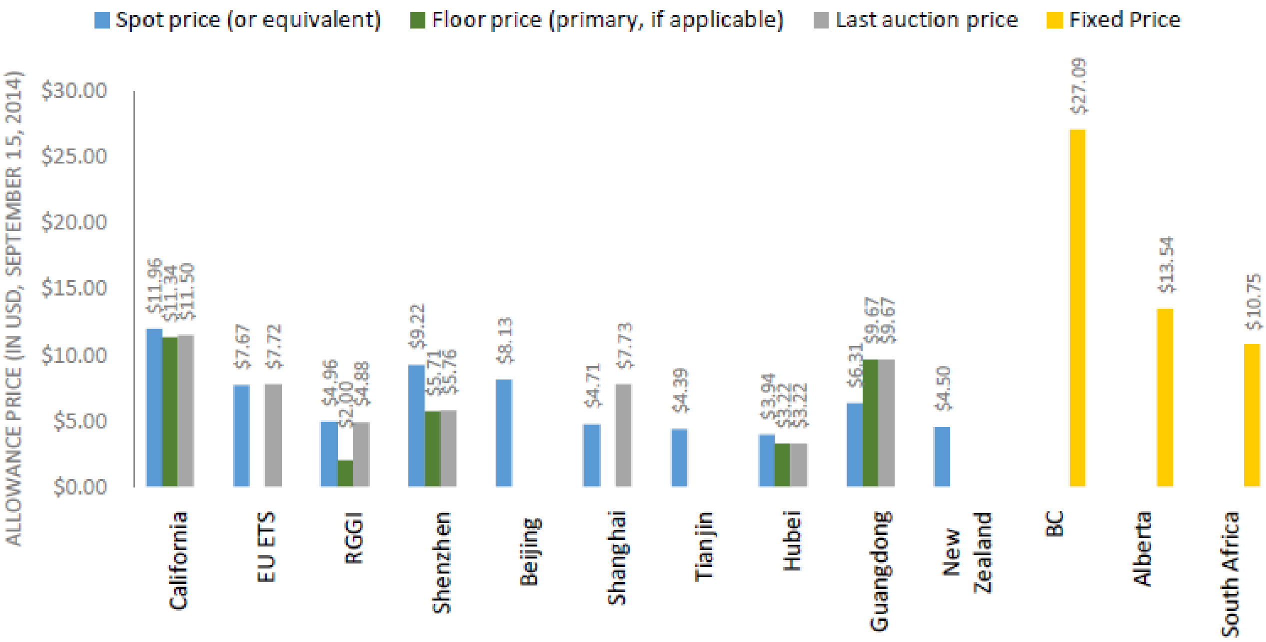
The Industrial Commission of North Dakota has repeatedly challenged application of the CO_2 regulatory cost values to out-of-state facilities, but to our knowledge the Commission has so far rejected this challenge, contending Minn. Stat.§ 216H.06 does not suggest there should be a different application of the regulatory cost values depending on location.[31] We have thus applied the CO_2 regulatory cost values to units both within and outside Minnesota.

2. *Perspective #1: CO_2 Prices in Existing Carbon Markets*

When the estimate of the likely range of costs of CO_2 regulation was first established in 2007, the values were based on expert forecasts of prices in carbon markets not yet in existence. Since that time, carbon markets have been put in place in some U.S. states and in other countries. Recent prices in these markets, shown in Figure 2 below, provide some perspective on the Commission's proxy for the cost of future carbon regulation.

[31] In its April 2014 decision in *State of North Dakota et al. v. Heydinger*, the U.S. District Court for the District of Minnesota concluded that Minn. Stat.§ 216H.03, subd. 3(2)-(3) "constitutes impermissible extraterritorial legislation and is a per se violation of the dormant Commerce Clause." However, this decision to our knowledge only affects the cited sections of the statute, not §216H.06 that governs the application of CO_2 regulatory cost values.

Figure 2: Global Carbon Prices (US dollars per metric ton of CO_2) as of September 2014



Source: California and the Carbon World, September 2014, from http://californiacarbon.info.[32]

Where CO_2 emissions are currently regulated and market-based mechanisms are available for compliance, prices are generally in the low end of the Commission's adopted range of $9-34/ton. In California, the CO_2 allowance price at the August 2014 auction was $11.50/metric tonne ($10.43/ton).[33] In the northeastern United States' Regional Greenhouse Gas Initiative (RGGI), the allowance price in the September 3, 2014 auction was $4.88/ton.[34] Only in one market, with a fixed price – British Columbia – was the CO_2 price above $20.

Thus our base assumption of $21.50/ton may be a conservatively high estimate of the costs that CO_2 regulations will impose on our customers. However, this assumes that state plans under EPA's 111(d) rule allow CO_2 markets or pricing mechanisms similar

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[32] Note that the carbon proxy range is in dollars per short ton of CO_2, whereas the prices in the figure are (with the exception of RGGI) in dollars per metric ton, so may be multiplied by 0.907 to give the analogous price per short ton.

[33] See August 18, 2014 California Air Resources Board auction results at: http://www.arb.ca.gov/cc/capandtrade/auction/august-2014/results.pdf. Prices were slightly higher in the November 25, 2014 joint California-Quebec auction, at $12.10/tonne ($10.97/short ton); results at https://www.wci-auction.org.

[34] See September 3, 2014 RGGI auction results at http://www.rggi.org/market/co2_auctions/results. The December 3, 2014 auction closed at $5.21/short ton.

to the markets above, or allow other compliance flexibilities that contain costs in a similar range. This remains uncertain at this time, and the ultimate cost of compliance will depend on the final 111(d) rule, whether the goals for our states are more or less stringent than those in the proposed rule, whether our states' 111(d) plans include market mechanisms and other compliance flexibilities, whether they collaborate with each other or with other states, and other factors. Based on the information currently available, we believe $21.50 remains a reasonable assumption.

3. *Perspective #2: Possible Alternatives to a CO_2 Price*

When the estimate of the likely range of costs of future CO_2 regulation was established in 2007, and for some years thereafter, there was a general expectation that CO_2 regulation would take the form of a market-based policy such as a carbon tax or cap and trade program. However, efforts to establish market-based carbon policy at the national level have failed; the American Clean Energy and Security Act (H.R. 2454) passed in 2009 by the U.S. House of Representatives failed to pass the Senate, and no similar cap and trade legislation has been introduced since. Discussions of a carbon tax proposal continue, but appear equally unlikely to secure bipartisan support.

The focus of climate policy has shifted to existing authorities, specifically section 111 of the Clean Air Act, as summarized in Section II.A of this Appendix. The EPA's proposed GHG rule for new power plants under CAA section 111(b) is an emission standard that new units must meet, with no market-based compliance option. The EPA's proposed rule for existing power plants under CAA section 111(d) allows states' plans to adopt market-based approaches, but does not require them to do so.

Thus the Commission may find it useful to consider other methods to simulate the effect of the 111(b) and 111(d) regulations. For example, the proposed 111(b) regulation mandates that any new coal plant emit no more than 1,100 lbs of CO_2 per MWh – an emissions rate only achievable through partial carbon capture and sequestration (CCS).[35] This mandate could be captured by including in the cost assumptions for any new coal plant the costs of capturing, transporting and sequestering enough CO_2 to reach the 1,100 lb/MWh standard.

In Minnesota, these costs would be high – even higher than in other parts of the country, since Minnesota has few geologic storage or enhanced oil recovery

[35] *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Generating Units*, Docket No. EPA-HQ-OAR-2013-0495, 79 Fed. Reg. 1,430 (Jan. 8, 2014). *See* http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants.

opportunities – and may make a new coal plant uneconomic. Similarly, the 111(d) existing source rules indicate multiple compliance pathways other than market-based mechanisms, making a carbon proxy price not the only, or necessarily the best way, to plan future resources.

As Minnesota's approach to 111(d) implementation becomes clearer over the coming years – for example, when it is known whether the state's 111(d) plan will include market mechanisms, whether the state will adopt an emission rate-based (lbs CO_2/MWh) or mass-based (total tons CO_2) approach, and whether the state will adopt a state-only compliance approach or collaborate with other states – the Commission may consider other ways to capture the potential cost of CO_2 regulation for the remaining years before 111(d) compliance goes into effect.

B. Environmental Externalities

Minn. Stat. § 216B.2422, subd. 3 required the establishment of a range of environmental costs (or "externality" values) associated with electricity generation, to be used when evaluating and selecting resource options in all proceedings before the Commission. The Commission established interim externality values in 1994 and final values in 1997 for sulfur dioxide (SO_2), carbon monoxide (CO), carbon dioxide (CO_2), oxides of nitrogen (NO_x), lead (Pb), and particulate matter less than 10 microns in diameter (PM_{10}).[36] Since their establishment, the externality values have been adjusted periodically using the U.S. Department of Commerce's GDP Deflator Index, but not otherwise updated.

The most recent inflation adjustment was issued May 22, 2014. Low and high values are provided for PM_{10}, CO, NO_x, Pb, and CO_2. For PM_{10}, CO, NO_x, and Pb; the values vary depending on the location of the emission source: urban, metropolitan fringe, rural, and within 200 miles of the Minnesota border. For CO_2, the low and high values are the same regardless of location, except that CO_2 is assigned a zero value outside of Minnesota. No externality value is provided for SO_2 due to the Commission's January 3, 1997 Order finding that SO_2 damages were considered internalized after 2000, when federal regulation was established for SO_2, and therefore continuing to apply externality costs would be unwarranted.[37]

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[36] ORDER ESTABLISHING ENVIRONMENTAL COST VALUES. *In the Matter of the Quantification of Environmental Costs Pursuant to Laws of Minnesota 1993, Chapter 356, Section 3*. Docket No. E999/CI-93-583. January 3, 1997.
[37] NOTICE OF COMMENT PERIOD ON UPDATED ENVIRONMENTAL EXTERNALITY VALUES. *In the Matter of the Investigation into Environmental and Socioeconomic Costs Under Minn. Stat. §216B.2422, Subd. 3*. Docket Nos. E999/CI-93-583 and E999/CI-00-1636. May 22, 2014.

The externality values must be used by utilities when evaluating resource options in all proceedings before the Commission, including Resource Plan and Certificate of Need proceedings. However the values are not themselves determinative; the Commission may consider other factors, including socioeconomic costs, when making its decisions, and the values are not applied to decisions regarding the dispatch of electricity.[38]

1. *Proceeding to Update Externality Values*

On October 9, 2013 the Minnesota Center for Environmental Advocacy, Izaak Walton League of America – Midwest Office, Fresh Energy, the Sierra Club, the Center for Energy and Environment, and the Will Steger Foundation petitioned the Commission to update its externality values for CO_2 and NO_x emissions, establish an externality value for $PM_{2.5}$, and reestablish an externality value for SO_2.[39] The Commission found that the scientific evidentiary support for the existing externality values had been reasonably called into question and granted the motion, referring the matter to the Office of Administrative Hearings for a contested case proceeding. The Commission also directed the Department and the MPCA to convene stakeholders to address the scope of the investigation, whether to retain an expert under Minn. Stat. § 216B.62, subd. 8, and the possible role of an expert.[40]

After receiving comments from the parties regarding the scope of the proceeding, the Commission held that:

- All four pollutants ($PM_{2.5}$, SO_2, NO_x, and CO_2) should be included in the contested case proceeding;
- Because CO_2 represents 99 percent of GHG emissions from power plants, an accurate environmental cost value for CO_2 will account for almost all GHG costs. Therefore, environmental costs of non-CO_2 GHGs will not be included in the investigation;
- The Commission agrees with the arguments from several parties that it would be premature to adopt the Social Cost of Carbon (SCC) values for CO_2 developed by a federal Interagency Working Group prior to the contested case

[38] ORDER ESTABLISHING ENVIRONMENTAL COST VALUES. *In the Matter of the Quantification of Environmental Costs Pursuant to Laws of Minnesota 1993, Chapter 356, Section 3*. Docket No. E999/CI-93-583. January 3, 1997.
[39] MEMORANDUM IN SUPPORT OF CLEAN ENERGY ORGANIZATIONS' MOTION TO UPDATE EXTERNALITY VALUES FOR USE IN RESOURCE DECISIONS. *In the Matter of the Quantification of Environmental Costs*. Docket No. E999/CI- 93-583. October 9, 2013.
[40] ORDER REOPENING INVESTIGATION AND CONVENING STAKEHOLDER GROUP TO PROVIDE RECOMMENDATIONS FOR CONTESTED CASE PROCEEDING. *In the Matter of the Investigation into Environmental and Socioeconomic Costs Under Minn. Stat. § 216B.2422, Subd. 3*. Docket No. E999/CI-00-1636. February 10, 2014.

proceeding. However, the Commission asked the Administrative Law Judge (ALJ) to determine whether the SCC is reasonable and the best available measure to determine the environmental cost of CO_2 and, if not, what measure is better supported by the evidence;

- Parties to the contested case proceeding must evaluate environmental costs using a damage cost approach, as opposed to (for example) market-based or cost-of-control values;
- The Department is authorized to take the steps necessary to retain a consultant under Minn. Stat. § 216B.62, subd. 8, if it determines such action is necessary. The Commission will play no role in the retention of a consultant and does not intend to communicate with the consultant;
- Reduced-form modeling shall be used to update externality values for $PM_{2.5}$, SO_2, and NO_x; and
- The proceeding shall be assigned a new docket number E999/CI-14-643.[41]

Northern States Power Company, doing business as Xcel Energy, petitioned to intervene in the contested case proceeding, since the environmental cost values ultimately adopted will have a significant impact on our resource planning decisions.

The assigned ALJ held a pre-hearing conference on November 25, 2014. The ALJ granted all petitions to intervene; requested the Department's attorney to develop a proposal for accepting public comment on the proceeding; requested memoranda from parties summarizing their views on which parties should bear the burden of proof in the proceeding; and set a schedule for the initial phases of the proceeding. The ALJ bifurcated the proceeding into separate schedules for discussion of CO_2 externality values and criteria pollutant externality values. Direct testimony related to externality values for CO_2 is due June 1, 2015. The due dates for direct testimony on criteria pollutants, as well as the schedule for the following steps (public hearings, rebuttal testimony, surrebuttal testimony, evidentiary hearing, initial briefs, reply briefs, and ALJ report), have not yet been set.

2. *Application of Externality Values in this Resource Plan*

Because the outcome of the proceeding to update environmental cost values remains unknown, our Strategist modeling uses the latest inflation-adjusted values as published by the Commission in May 2014:

[41] NOTICE AND ORDER FOR HEARING. *In the Matter of the Investigation into Environmental and Socioeconomic Costs Under Minn. Stat. § 216B.2422, Subd. 3.* Docket Nos. E999/CI-00-1636 and E999/CI-14-643. October 15, 2014.

- For PM_{10}, CO, NO_x, and Pb, all modeled scenarios use the High externality value, chosen by location of emission source (urban, metro fringe, rural, within 200 miles from state line). We have also modeled zero values as a sensitivity. We have not modeled the Low externality values, since they will not drive a different decision;
- For SO_2, modeled scenarios do not incorporate externality values, per the Commission's current guidance;[42] and
- We did not apply the Commission's current CO_2 externality values of $0.43 to $4.46/ton because these are well below the CO_2 regulatory proxy cost midpoint of $21.50/ton, which we applied in all scenarios. Per the Commission's current guidance, utilities need not apply the CO_2 externality value in any year in which they apply the CO_2 regulatory proxy cost value.[43] In our judgment, applying the relatively low CO_2 externality values in 2015-2018 prior to shifting to the $21.50 CO_2 regulatory proxy midpoint in 2019 would not drive different outcomes.

For CO_2, a sensitivity was run in which we applied the federal SCC.[44] We selected the 3 percent discount rate variant of the SCC developed by the federal Interagency Working Group, which we converted from 2007 dollars per metric ton of CO_2 into inflation-adjusted dollars per short ton of CO_2. As indicated in our comments in Docket No. E999/CI-00-1636, Xcel Energy does not support the adoption of the 3 percent discount rate SCC as the sole CO_2 externality value to update environmental cost values. We believe the Commission should consider the full range of options for assigning appropriate damage cost values to CO_2 emissions, and set a range of values considering different discount rate options and the high level of uncertainty in the

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[42] "In the January 3, 1997 Order Establishing Environmental Cost Values the Commission found that SO_2 damages would be internalized after 2000 and applying externality costs would be unwarranted." See NOTICE OF COMMENT PERIOD ON UPDATED ENVIRONMENTAL EXTERNALITY VALUES. *In the Matter of the Investigation into Environmental and Socioeconomic Costs Under Minn. Stat. §216B.2422, Subd. 3.* Docket Nos. E999/CI-93-583 and E999/CI-00-1636. May 22, 2014. Page 6.

[43] "A utility need not apply the CO_2 externality values… established pursuant to Minn. Stat.§216B.2422, subd. 3, in any year to which the utility applies the CO_2 costs derived pursuant to Minn. Stat. §216H.06" See NOTICE OF COMMENT PERIOD ON UPDATED ENVIRONMENTAL EXTERNALITY VALUES. *In the Matter of the Investigation into Environmental and Socioeconomic Costs Under Minn. Stat. §216B.2422, Subd. 3.* Docket Nos. E999/CI-93-583 and E999/CI-00-1636. May 22, 2014. Page 7.

[44] *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.* Interagency Working Group on Social Cost of Carbon, United States Government. May 2013 – Revised November 2013.

SCC.[45] The SCC is imprecise, is methodologically and procedurally flawed, is intended for the limited purpose of federal regulatory impact analysis that is fundamentally different from utility resource planning, and has yet to be finalized by the federal Office of Management and Budget in response to public comments taken in March 2014. Thus, we emphasize that we have applied the SCC values in this Resource Plan only as a sensitivity, to examine the implications for resource choices and costs without any suggestion that the SCC is an appropriate approach.

C. Minnesota GHG Goals

The Next Generation Energy Act (NGEA) of 2007 stated that:

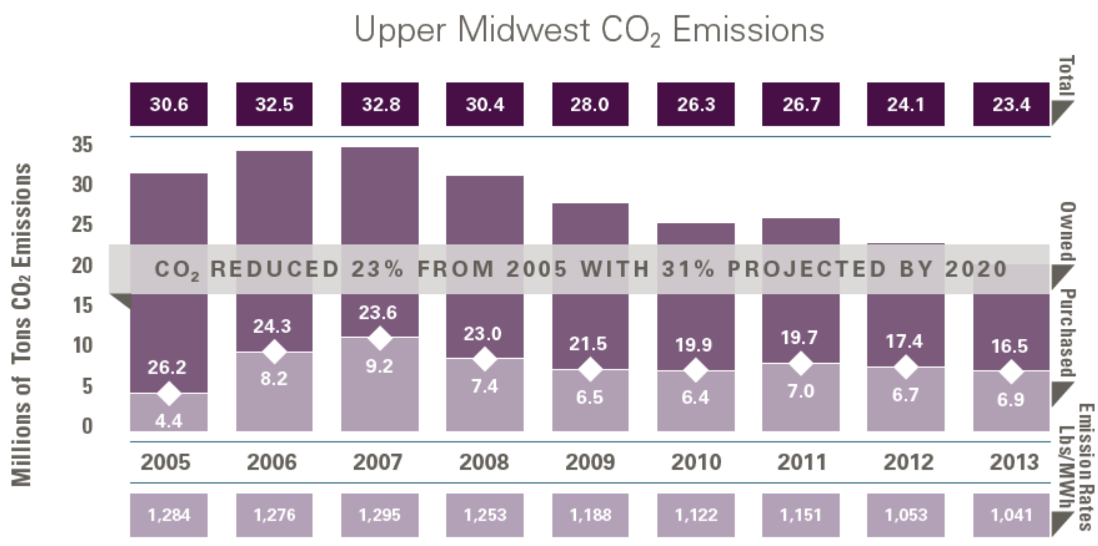
> *It is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050.*[46]

According to the MPCA, between 2005 and 2010 Minnesota's overall GHG emissions declined by 5 million tons CO_2e, or about 3 percent, with the most significant reductions coming from electric power utilities and transportation energy use. GHG emissions from the electric sector accounted for 32 percent of the state's total in 2010, and between 2005 and 2010 declined by about 13 percent.[47]

The Company's GHG emissions have declined more than those of the electric sector overall. In the base year of 2005, NSP's carbon dioxide emissions from owned and purchased power were 30.6 million short tons; by 2013, these had declined to 23.4 million tons, a decrease of 23 percent. The Company's CO_2 intensity from owned and purchased power declined over the same period from 1,284 lbs/MWh to 1,041 lbs/MWh, a decrease of 19 percent. See Figure 3 below.

[45] See Xcel Energy initial comments (November 8, 2013), reply comments (November 18, 2013), comments to Department of Commerce – Division of Energy Resources and the Pollution Control Agency (May 9, 2014), and comments on the agencies' recommendations (June 26, 2014*). In the Matter of the Investigation into Environmental and Socioeconomic Costs Under Minn. Stat.. § 216B.2422, subd. 3.* Docket No. E999/CI-00-1636.
[46] Minn. Stat. § 216H.02, subd. 1.
[47] See http://www.pca.state.mn.us/index.php/topics/climate-change/climate-change-in-minnesota/report-on-greenhouse-gas-emissions-in-minnesota.html.

Figure 3: CO_2 emissions from owned and purchased power, Northern States Power Company, 2005 to 2013



These declines in total CO_2 emissions and CO_2 emission intensity are the result of a proactive strategy by the Company, implemented in cooperation with the Minnesota Public Utilities Commission and Minnesota Legislature, that includes retirement of coal power plants and repowering to gas under the Metropolitan Emissions Reduction Project; addition of renewable resources, particularly wind, with lesser shares of biomass and solar; DSM program energy savings; and nuclear uprates.

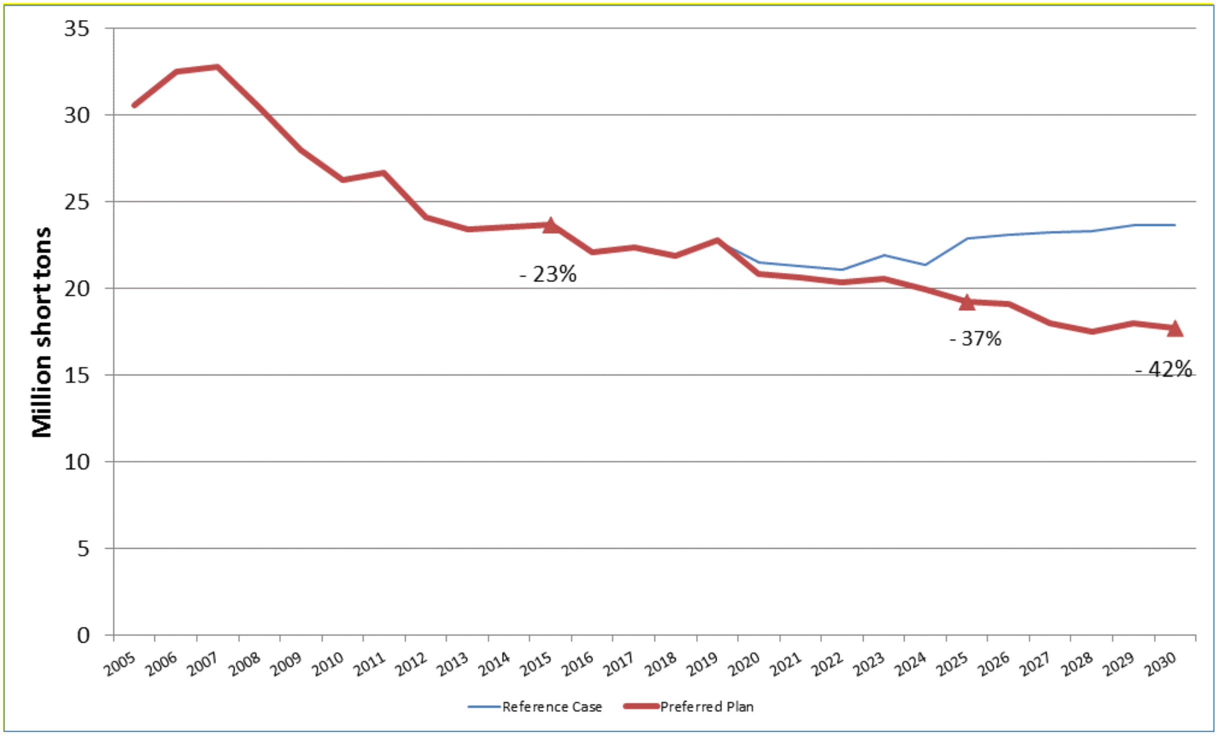
1. *Minnesota's 2015 Goal*

As of 2013 the Company had already exceeded the NGEA goal for 2015. Under the Preferred Plan, the Company's CO_2 emissions from owned and purchased power are projected to be 23.7 million tons, or 23 percent below 2005 levels. See Figure 4 below.

2. *Minnesota's 2025 Goal*

Under the Preferred Plan, the Company is on track to exceed the NGEA goal of 30 percent below 2005 levels in 2025. Our CO_2 emissions from owned and purchased power would be 19.2 million tons in that year, or 37 percent below 2005 levels. See Figure 4 below.

Figure 4: NSP CO_2 emissions from owned and purchased power, under Reference Case and Preferred Plan



Note: Chart shows CO_2 emissions from 2005 to 2030 (actual emissions for 2005 through 2013, forecast emissions for 2014 through 2030). Percentage reductions are relative to 2005.

3. *Non-CO_2 Greenhouse Gas Emissions*

The above estimates for emissions, emissions intensity, and percent reductions are for CO_2 only, not non-CO_2 greenhouse gases. Emissions of methane (CH_4) and nitrous oxide (N_2O) from power plants are generally about six orders of magnitude lower than emissions of CO_2. While methane and nitrous oxide do have significantly higher Global Warming Potential (GWP) factors than CO_2, these two gases contribute only an additional one half of one percent to total CO_2 emissions even after multiplying these by GWP factors to put their impacts in terms of CO_2 equivalents.[48]

Since the Commission's requirement is to evaluate progress against the statewide GHG reduction goals in percentage terms, the very small non-CO_2 GHG emissions would be added to both the base year of 2005 and the target years of 2015 and 2025. Emissions of non-CO_2 GHGs from power generation are likely to have negligible effects on achievement of the State goals.[49]

4. *Minnesota's 2050 Goal*

The NGEA includes a statewide goal to reduce GHG emissions "across all sectors producing those emissions… to a level at least 80 percent below 2005 levels by 2050."[50] Also, in 2014 the Minnesota Legislature passed energy legislation that requires:

> *Long-range emission reduction planning.* Each utility required to file a resource plan under subdivision 2 shall include in the filing a narrative identifying and describing the costs, opportunities, and technical barriers to the utility continuing to make progress on its system toward achieving the state greenhouse gas emission reduction goals established in section 216H.02, subdivision 1, and the technologies, alternatives, and steps the utility is considering to address those opportunities and barriers.[51]

Since the Company already projects achievement of the goals for 2015 and 2025, we address here only the costs, opportunities, and technical barriers relative to the 2050 goal.

A GHG reduction of 42 percent below 2005 in 2030 under the Preferred Plan represents strong progress toward the 2050 goal; however, it is important to

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[48] Examination of the USEPA's Emissions & Generation Resource Integrated Database (eGRID) substantiates these conclusions (http://epa.gov/cleanenergy/energy-resources/egrid/index.html). For example, the latest (Ninth Edition) eGRID data shows that for the MRO West region, the output emission rate of CO_2 was 1,536 lb/MWh while the output emission rate of CH_4 was 28.53 lb/GWh (0.028 lb/MWh) and the output emission rate of N_2O was 26.29 lb/GWh (0.026 lb/MWh). Once the CH_4 and N_2O emissions are multiplied by their 100-year GWP factors and added to the CO_2 emissions, the total CO_2-equivalent output emission rate is 1,545 lb/MWh, or 0.57 percent greater than the output emission rate for CO_2 alone. This is not a characteristic specific to MRO West or to this particular year; the order-of-magnitude differences are relatively consistent across eGRID regions and across years, simply reflecting the relatively efficient combustion in modern power plants.

[49] For added detail see Xcel Energy's Reply Comments, *Southern Minnesota Municipal Power Agency's (SMMPA) 2014-2028 Integrated Resource Plan.* Docket No. ET9/RP-13-1104. May 27, 2014.

[50] Minn. Stat. 216H.02, subd. 1.

[51] HF2834, signed into law May 16, 2014, Sec. 13 Subd. 2c.

acknowledge that an 80 percent reduction in GHG emissions implies a complete transformation in the way electricity is produced and used. The Company's CO_2 emissions of 30.6 million tons in 2005 would need to decline to about 6 million tons per year by 2050.[52,53] This means an electricity generation, transmission, distribution and storage system that is largely carbon-free, supported by a small fossil fuel share – probably highly efficient natural gas combined cycle and combustion turbines – used primarily for integrating intermittent renewables and to a limited extent for peaking power and ancillary service needs. It would likely require energy storage technologies not available today.

Importantly, each increment of CO_2 reduction may be more challenging and costly than the last. Initially, it was possible to retire relatively older, smaller and less efficient coal units, to invest in the most cost-effective renewable resources, and to invest in the "low-hanging fruit" among DSM opportunities. To reach an 80 percent reduction implies retiring larger, highly efficient and cost-effective baseload units, whose generation is expensive to replace. It means developing potentially more expensive renewable resources (though this may be mitigated to some extent by declining costs), and capturing more difficult and costly DSM savings. It may mean less portfolio diversity and greater reliance on a single fuel (natural gas), with historically volatile prices. There could be greater challenges managing reliability in a system increasingly made up of variable resources.

a. Key variables and unknowns

Utility business models and regulatory frameworks may change. An 80 percent CO_2 reduction could be pursued primarily under the model in place today – a vertically integrated utility operating under cost-of-service regulation and investing primarily in large-scale, centralized generation – or under new utility business models and regulatory frameworks in which electricity generation, distribution and storage are more decentralized, with an increasing role for unregulated actors in the marketplace.

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[52] This interprets the 80 percent reduction goal in reference to the CO_2 emissions from electricity supply (owned and purchased) of Northern States Power Company overall. The goal could instead be interpreted as applicable to NSP-Minnesota electricity emissions, not the share assigned to NSP-Wisconsin, since Wisconsin does not have a GHG reduction goal comparable to Minnesota's; or as applicable only to CO_2 emissions from electric generating facilities physically located in Minnesota. However the NSP system generation portfolio is operated as an integrated system, with costs and revenues allocated per the FERC interchange agreement between NSP-Minnesota and NSP-Wisconsin, and the Company generally does not attempt to split CO_2 emissions or emission reductions between NSP-Minnesota and NSP-Wisconsin.

[53] The City of Minneapolis has adopted a similar goal, but using a 2006 rather than 2005 baseline. An 80 percent reduction from the Company's 2006 CO_2 emissions from owned and purchased power (32.5 million tons) would allow slightly higher annual CO_2 emissions, at 6.5 million tons.

Centralized utility-scale renewables are today significantly more cost-effective, in terms of levelized cost per MWh or cost per ton of CO_2 abatement, than decentralized distributed generation and storage. Achieving an 80 percent reduction could be more costly in a distributed framework that does not enjoy the same economies of scale and bargaining leverage in power purchase agreements that large centralized utilities have historically enjoyed. However, technology and costs are evolving rapidly – as are utility business models, regulatory frameworks, and customer preferences – so we cannot assume the same structure will exist in 2050 as exists today.

The future of our nuclear units is unclear. NSP's almost 1,700 MW of baseload nuclear power represent a highly cost-effective resource that is a large contributor to our ability to provide our customers 51 percent carbon-free energy today.[54] These units are currently slated for retirement in 2030 (Monticello), 2033 (Prairie Island Unit 1), and 2034 (Prairie Island Unit 2). If they retire as planned, this generation will have to be replaced by other carbon-free options; if they are replaced by intermittent renewables, significantly more MW will have to be installed than the baseload nuclear MW retiring, and these resources will have to be balanced with CO_2-emitting natural gas or with large-scale energy storage. While the Company has not yet begun the formal process to meet Nuclear Regulatory Commission (NRC) requirements for license renewal beyond 60 years, we have made life cycle management investments that have positioned Monticello and Prairie Island to operate safely and reliably long into the future. Achieving CO_2 reductions of 80 percent will be much more challenging without these units.

Large-scale energy storage technologies are not available today. Only scattered examples of large-scale bulk power storage, such as pumped hydro, exist today. Xcel Energy and other utilities are exploring battery technologies as a means to balance intermittent wind and solar generation and to better match their generation to load. Battery costs are declining, and battery storage may one day be available at commercial scale, but costs are still high and the largest examples today are only in the 1 to 8 MW range.[55] Without large-scale, lower-cost storage options, and with a 6 million ton CO_2/year constraint on natural gas generation, it will be challenging to integrate 80 percent or more intermittent renewable energy. Some types of renewable generation, such as hydro and biomass, can function as baseload resources, but the cost of new capacity is high.

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[54] Approximately 60 percent of our clean non-carbon emitting energy comes from Monticello and Prairie Island.

[55] See http://www.businessweek.com/news/2014-10-13/giant-battery-unit-aims-at-wind-storage-holy-grail-commodities#p2.

The price of natural gas is a key driver, and historically volatile. The shale gas revolution and hydraulic fracturing have revolutionized the natural gas industry, resulting in lower long-term natural gas price forecasts. Our current modeling uses a current gas price of around $4.00/MMbtu, escalating to around $10 in 2050 in the reference scenario (with sensitivities from $6 to $15/MMbtu in 2050). However, it is not possible to predict gas prices in 2050. A higher or lower gas price will affect the mix of resources and the overall cost of achieving an 80 percent CO_2 reduction. A higher gas price would make wind and solar more competitive, but also increase the costs of natural gas generation needed to balance their variable generation. A lower gas price would make natural gas generation more competitive, but since total natural gas generation will be limited by the 6 million ton annual CO_2 cap, the Company would still be required to meet most of its load with carbon-free resources, and the cost to our ratepayers (relative to natural gas generation) would be higher. Significantly greater reliance on natural gas also exposes our customers to greater fuel price risk.

b. Costs, opportunities and technical barriers

The box at the right qualitatively characterizes generation technologies by levelized cost of electricity, as of today, not including externalized costs or benefits. The costs of some technologies are declining quickly. Since technological advances and future costs are so difficult to predict, particularly to 2050, we have not attempted to attach specific long-term cost estimates to any of these technologies.

Cost, technical, and political barriers to achieve an 80 percent CO_2 reduction include, but are not limited to:

- Costs of renewable generation, particularly in the absence of the PTC and ITC, remain higher than fossil alternatives. However, the costs of fossil alternatives could increase, and the costs of many renewable technologies are declining.

Most mature and lowest cost:

- Existing coal, nuclear, hydro for baseload power
- Natural gas combined cycle and combustion turbines for intermediate and peaking power and for balancing renewable generation
- Wind, especially with tax credits

Medium maturity and/or cost:

- Wind without tax credits
- Utility-scale solar and solar gardens, with tax credits
- Biomass

Least mature and/or highest cost:

- New coal with CCS (as may be required by the EPA's 111(b) proposed rule)
- New nuclear
- Distributed rooftop solar
- Energy storage (battery) technologies

- While experience with renewable integration is growing quickly, integrating much higher (80 percent or more) levels of intermittent renewable generation will be a challenge – particularly if commercial scale energy storage remains unavailable or prohibitively expensive, and our ability to use natural gas units for load following is limited by the 6 million tons CO_2/year cap.
- Environmental regulations are generally making it more difficult to maintain a diverse energy portfolio, which can mean higher and more volatile costs and a greater challenge to provide reliable and affordable electricity. Public reaction to higher costs could make it more difficult to secure support for ongoing CO_2 reductions.
- Public opposition to nuclear power, and the lack of a long-term solution for nuclear waste management, could make it more difficult to extend the licenses of our existing nuclear units, resulting in higher costs to achieve an 80 percent CO_2 reduction.
- Public opposition to other baseload zero-carbon or low-carbon alternatives, including hydro and biomass, is generally increasing as well.
- Today CO_2 capture and storage is challenged by the cost of CO_2 capture, parasitic load, cost of CO_2 transport to areas with better geologic sequestration options than Minnesota, and concerns related to long-term liability and permanence of storage. If CCS remains unavailable in 2050, less fossil generation will be possible within the 6 million tons CO_2/year cap.
- Today the cost of small-scale, distributed generation and storage makes these a relatively higher-cost way to achieve an 80 percent CO_2 reduction. If the cost of solar PV, smart grid infrastructure, and energy storage decline significantly, with batteries and electric vehicles (EVs) integrated into the grid becoming the primary means for balancing renewable generation with load, this scenario becomes more feasible.

c. Steps Xcel Energy is taking to address these opportunities and barriers

Xcel Energy is working to address these barriers and explore new opportunities through:

Continued investment in carbon-free generation. We continue to invest in wind and solar resources. The 1,867 MW of wind currently in our Upper Midwest portfolio will increase to 2,617 MW by 2016 under previous Commission decisions. Under the Preferred Plan, we propose to add another 1,800 MW of wind by 2030. Our solar energy portfolio, under the Preferred Plan, will grow to 1,887 MW of large solar plus

506 MW of small solar. We are on track to meet the mandate of 1.5 percent solar energy by 2020, and under the Preferred Plan propose to increase solar energy's contribution to 10 percent of NSP retail sales by 2030.

Sophisticated wind forecasting. As our renewable portfolio grows, we are pursuing a number of industry-leading initiatives to improve the operation and integration of variable energy. Since 2009, we have worked with Global Weather Corp., an affiliate company of the National Center for Atmospheric Research, to implement a highly detailed forecasting system that has increased our wind forecasting accuracy by more than 37 percent since 2009, and saved customers an estimated $37.5 million in fuel costs through more efficient dispatch of our generating units. Improving our ability to predict and dispatch variable resources has allowed for the off-line cycling of baseload resources. We now regularly park fossil-fuel plants at low production levels and use wind energy for system balancing.

Energy storage research and development. Xcel Energy is currently testing two battery storage projects at our Solar Technology Acceleration Center (SolarTAC) in Colorado. The first uses a 1.5 MW battery to smooth fluctuations that can occur when solar output from large-scale installations changes rapidly due to cloud cover or other factors. In the second, we are examining how smaller battery technology can mitigate the effects of high solar penetration in residential areas. A 25 kW battery is connected to four simulated homes powered by photovoltaic panels, modeling solar integration in a neighborhood. We also are working with the Electric Power Research Institute (EPRI) on a smart inverter project that will improve the integration of solar power. In our earlier Wind2Battery (W2B) project, we tested a 1 MW battery energy storage system connected directly to a wind farm, storing wind energy to return it to the grid when needed. Fully charged, the battery could power 500 homes for more than seven hours. Benefits include expected long-term emission reductions from increased availability of wind, reduction of impacts of wind variability, and modernization of the grid to allow for easier integration of renewable energy sources. The W2B project has provided us with experience and information that will allow us to assess and improve upon the viability of scaling-up battery storage on our system as more wind power is added to meet the renewable policies in the states we serve.

Electric vehicle (EV) research and deployment. Xcel Energy created the Repowering Transportation group in 2011, an internal team working on a comprehensive strategy to enable electrified transportation. We participate in community events to educate our customers about charging options, the benefits of EVs, specialized rate options for EV charging, and options to drive with 100 percent renewable energy by participating in *Drive with GUST-o* (residential charging of EVs with WindSource) and *Zero Emissions Challenge* (EV charging in public and workplace locations). We are also a partner in Drive Electric Minnesota (DEM), working with local and state governments, businesses and non-profits to bring EVs and plug-in charging infrastructure to Minnesota. Xcel Energy collaborated with DEM to facilitate the purchase of 12 Transit Connect electric vehicles for demonstration in highly visible fleets, and supported the installation of 76 public charging stations in city, university, and public transit locations.

The value of transportation electrification includes both GHG reduction and, in the future, a possibility for distributed energy storage. The transportation sector is the second-largest source of GHG emissions in Minnesota, responsible for 24 percent of emissions.[56] Shifting vehicles to electricity not only reduces GHG emissions at the tailpipe – EV emissions are about one-third lower than conventional internal combustion engine vehicles[57] – but can also reduce overall emissions as Xcel Energy continues to reduce the CO_2 intensity of our generation portfolio. This enables us to support Minnesota's 80 percent by 2050 goal even beyond our own sector. Over time as vehicle-to-grid (V2G) technology improves, EVs may become an important way to store energy and balance increasing penetration levels of renewable generation with load.

Support for renewable energy deployment and demonstrations. The Renewable Development Fund (RDF), financed by our Minnesota and Wisconsin electricity customers, supports the startup, expansion and attraction of renewable electric energy projects and companies. RDF also stimulates research and development into renewable electric energy technologies. Our RDF efforts are designed to increase the market penetration of renewable electric energy resources at reasonable costs. Our latest (March 2014) RDF grant cycle awards include 29 projects totaling $42 million, in the areas of energy production, research and development projects, and educational research initiatives.[58]

Monitoring CCS technology, cost and regulations. Xcel Energy is not conducting CCS tests at any of our power plants, but we monitor on an ongoing basis the evolution of CCS technologies, costs, and regulations affecting CO_2 injection and long-term storage. We also participate in and co-fund the U.S. Department of

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[56] Data for 2010 from MPCA; see http://www.pca.state.mn.us/index.php/topics/climate-change/climate-change-in-minnesota/report-on-greenhouse-gas-emissions-in-minnesota.html.
[57] http://www.afdc.energy.gov/vehicles/electric_emissions.php.
[58] A list of funded projects is at https://www.xcelenergy.com/staticfiles/xe/Corporate/Corporate%20PDFs/RDFCurrent%20Funding%20Cycle_Projects.pdf.

Energy's Plains Carbon Dioxide Reduction Partnership (PCOR).[59] Commercially viable CCS on gas would allow more natural gas generation, and possibly even some CCS retrofits on the most advanced existing coal units (Sherco 3 and King), to exist within the 6 million tons CO_2 per year constraint. However, Minnesota has no favorable geologic formations for sequestration, so this would also require build-out of CO_2 pipelines to more favorable regions.

Exploring new utility business models and regulatory frameworks. Xcel Energy actively participates in the e21 Initiative, which is evaluating new ratemaking models that would, among other objectives, "align utility and customer interests with the pursuit of Minnesota's goal of an 80 percent reduction in GHGs by 2050 and the transition to a sustainable, carbon neutral energy system."[60] On December 22, 2014, we submitted a letter to the Commission that builds on the e21 recommendations and seeks to advance the discussion on how to put these into action. Four areas prioritized are cost-effective carbon reductions of 40 percent by 2030, distribution grid modernization, providing our customers with new innovative services and products, and implementation of a new regulatory framework that allows predictable rates and more timely reviews.

Minnesota Energy Future Framework (MEFF). Xcel Energy participates on the core team of the MEFF, which is evaluating pathways to achieve 80-100 percent clean energy in the electricity, buildings, industrial, transportation and agricultural sectors in Minnesota, by 2030 or 2050.[61] The 80-100 percent "clean energy" goal is not explicitly a GHG emissions goal, and MEFF plans to conduct stakeholder dialogues around the state to better define what constitutes "clean energy." However, the generation resources currently being considered for the electric sector are all low- or zero-carbon resources.

5. *City of Minneapolis carbon goals*

We are working with the City of Minneapolis to design a new Clean Energy Partnership Agreement that would, among other objectives, help achieve the City's *Climate Action Plan* goals. The *Climate Action Plan* includes the objective to reduce citywide GHG emissions 15 percent by 2015 and 30 percent by 2025, using 2006 as a

[59] *See* http://www.undeerc.org/pcor/About/.
[60] http://www.betterenergy.org/projects/e21
[61] http://mn.gov/commerce/energy/topics/resources/energy-legislation-initiatives/studies-and-reports/minnesota-energy-future.jsp)

baseline. Thus the City's goals are similar to the NGEA goals, except for a different base year.

The City notes that its overall GHG emissions have declined 15 percent between 2006 and 2012, including over 7 percent between 2011 and 2012 alone; and "this change was driven in part by a change in the greenhouse gas intensity of electricity provided by Xcel Energy, which decreased by about 11 percent from 2011."[62]

The Company is on track to achieve the City's 2015 goal; under our Preferred Plan, our CO_2 emissions from owned and purchased power are projected to be 23.7 million tons in 2015, or 27 percent below 2006 levels. We are also on track to achieve the City's 2025 goal; under the Preferred Plan, our CO_2 emissions from owned and purchased power are projected to be 19.2 million tons in 2025, or 41 percent below 2006 levels.

The City has also adopted a long-term goal to reduce City-wide GHG emissions by 80 percent or more by 2050, from 2006 levels.[63] A GHG reduction of 80 percent below 2006 levels by 2050 implies a complete transformation in the way electricity is produced and used in the Upper Midwest. See the preceding section for discussion of the costs, opportunities, and technical barriers to achieving this goal.

IV. ENVIRONMENTAL PERFORMANCE

In this section, we detail our performance against existing environmental benchmarks illustrating our favorable performance to-date and our anticipated performance into the future.

A. Carbon Dioxide Emissions

Carbon dioxide is the leading greenhouse gas from the electric power sector linked to climate change. Xcel Energy has worked proactively with our public utility commissions, state legislatures, environmental and other stakeholders to reduce total CO_2 emissions from owned and purchased power over the last several years. Companywide – including all three Xcel Energy operating companies – we have reduced CO_2 emissions by 19 percent since 2005, with 31 percent reductions from

[62] See http://www.minneapolismn.gov/sustainability/climate/index.htm and http://www.minneapolismn.gov/sustainability/indicators/WCMS1P-087163.
[63] The 3050 goal was adopted by the City Council's Health, Environment & Community Engagement Committee on April 14, 2014, and by the City Council on April 25, 2014.

2005 levels projected by 2020. For the NSP system, the corresponding percentage reductions are 23 percent since 2005 and 32 percent below 2005 by 2020. Just over half of the electricity provided by the NSP system in 2013 was from carbon-free resources. The figures below illustrate these outcomes:

Figure 5: NSP CO_2 Emissions from Owned and Purchased Power 2005 through 2013

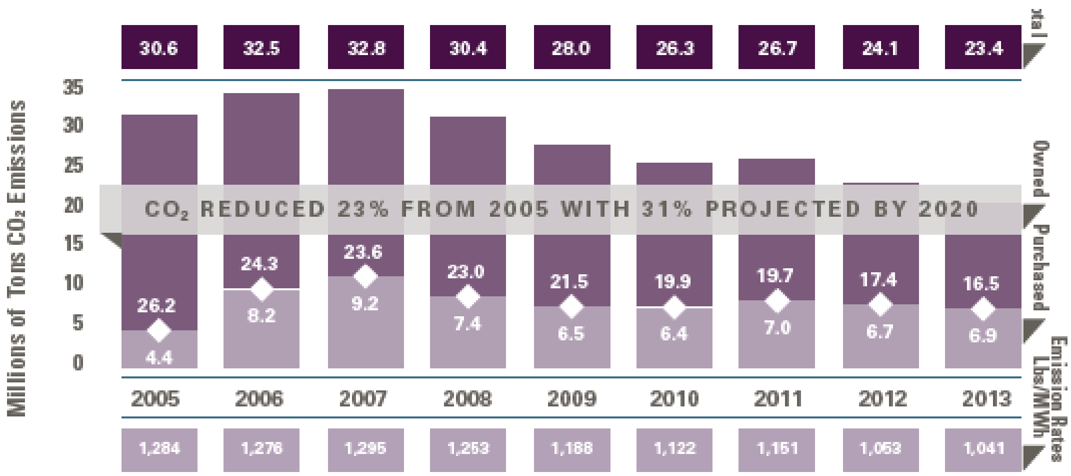
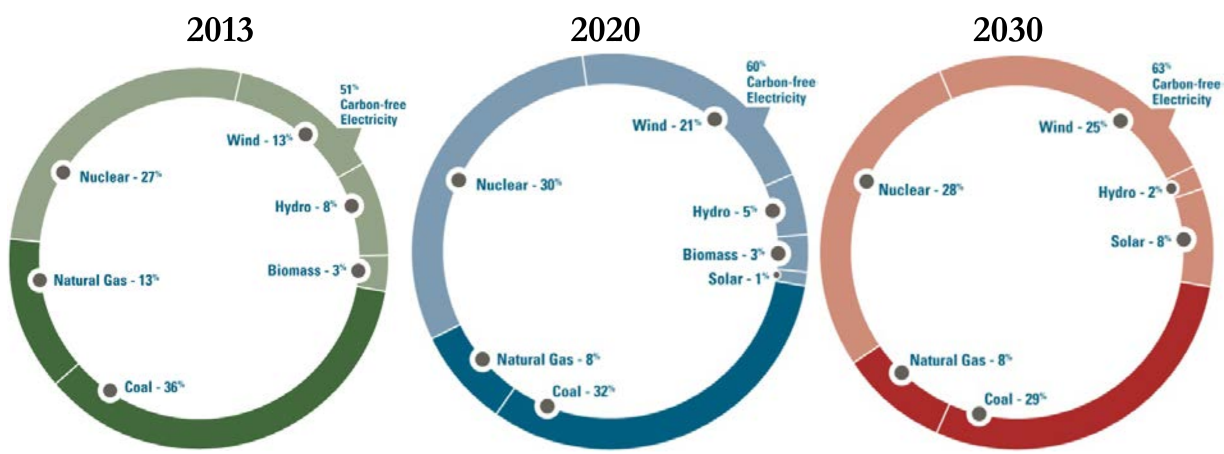


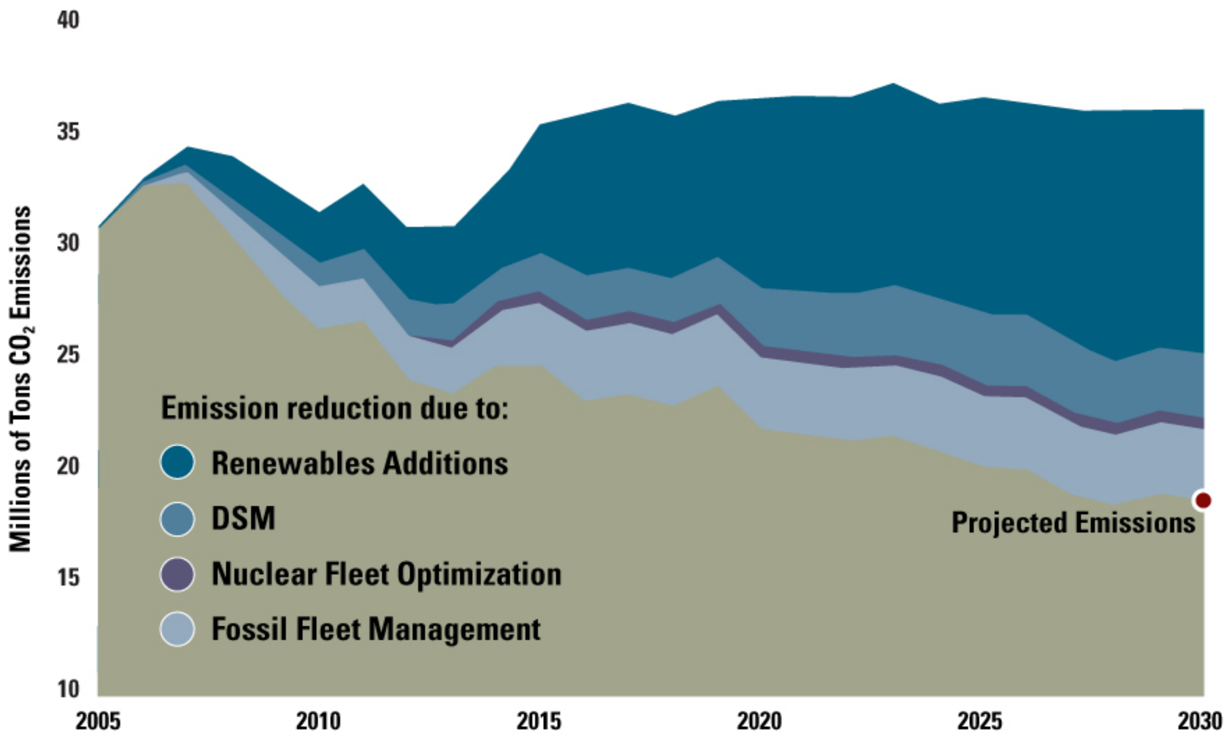
Figure 6: NSP System Electricity Supply by Fuel Type Actual for 2013; 2020 and 2030 under the Preferred Plan



Note: Includes owned and purchased energy.

Our CO_2 reduction strategy has three primary planks: (1) the increased use of renewable resources; (2) energy saving programs for customers; and (3) fleet modernization initiatives that identify coal-fired power plants for retirement and/or repowering. Nuclear fleet optimization also plays a role. The relative contributions of each strategy to our CO_2 reductions are shown below.

Figure 7: NSP CO_2 reductions by source, 2005-2030



Xcel Energy publicly reports annual CO_2 emissions, as well as other greenhouse gases, through a number of different reporting programs, including The Climate Registry, The Carbon Disclosure Project, and mandatory GHG reporting to the U.S. Environmental Protection Agency.

Electricity production is Xcel Energy's most significant source of emissions. We consistently report emissions associated with electricity production in short tons and in pounds per megawatt hour in our annual form 10-K and Corporate Responsibility Report. This allows users of these reports to follow our company's emissions trend.

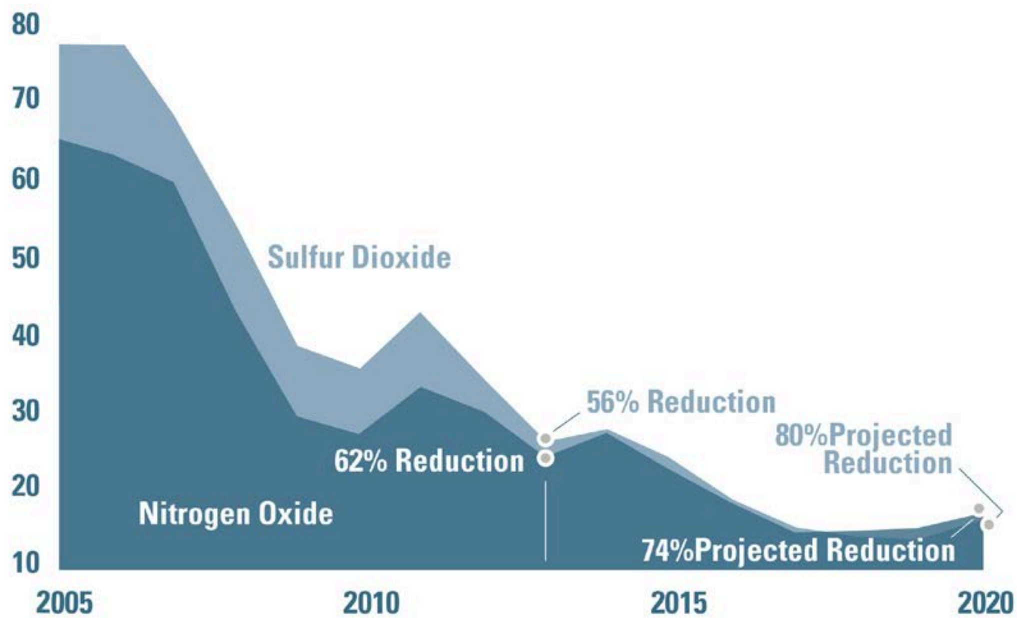
The Climate Registry is a nonprofit organization established to provide consistent and transparent standards for calculating, verifying and reporting GHG emissions into a single registry for North America. Xcel Energy recognizes the value of using a formal emissions protocol and completing third-party verification for emissions reporting. We joined The Climate Registry as a founding member in 2007, and have since worked to third-party verify and register all of our CO_2 emissions going back to 2005.

Verification for 2008 and 2011 is complete, and verification for all remaining years through 2012 is anticipated to be done in 2014.

B. Criteria Pollutant Emissions

The addition of emissions controls, fleet modernization efforts, renewable capacity additions, and increased energy efficiency savings have also helped reduce the NSP system's emissions of criteria pollutants over time. Figure 8 below shows our reductions in emissions of NO_x and SO_2 since 2005, projected out to 2020:

Figure 8: NSP Emissions of NO_x and SO_2
2005 to 2020



We continue to implement retirement, retrofit, efficiency, and emission control projects on NSP owned generation facilities. Table 6 below summarizes the current status of these projects as of the end of 2013:

Table 6: Efficiency, Control and Retirement Projects on NSP System-Owned Generation Facilities as of 2013

Location	Project Description	Completion Date
Sherco Units 1 and 2	Emission control upgrades: Sparger project for additional SO_2 reductions, as well as tuning and installation of combustion controls and coal mill improvements for additional NO_x reductions.	2014
Sherco Units 1 and 2	Installation of activated carbon injection (ACI) systems for mercury emission controls with a goal of 90 percent reduction.	2014
Black Dog Units 3 and 4	Retire coal boiler and generator	2015
Bay Front Units 1 and 2	Installation of fabric filters for particulate control and activated carbon injection for mercury control.	2014
Bay Front Unit 5	Cease burning coal; burn natural gas only	2015
St. Anthony Falls Hydro – Units 5 and 6	Turbine upgrades to improve efficiency 82 percent and increase power 6 percent.	2013
Big Falls Hydro - Unit 2	Turbine upgrade to improve efficiency 92 percent and increase power 16 percent.	2013
Wissota Hydro – Unit 2	Turbine upgrade to improve efficiency 90 percent and increase power 26 percent.	2013

C. Coal Plant Retirements and Retrofits

Through the Metropolitan Emissions Reduction Project, implemented in 2003-2009, the Company retired coal units at the Riverside and High Bridge facilities totaling 652 MW and constructed high-efficiency natural gas combined cycle units totaling 1,035 MW. We also installed state-of-the-art environmental controls on our 550 MW King coal plant. The project reduced CO_2 emissions from those plants by 21 percent, SO_2 by 93 percent, NO_x by 91 percent and mercury by 81 percent.[64]

Our Black Dog coal units 3 and 4 will be retired in 2015, and Bay Front Unit 5 will cease burning coal in 2015.

[64] See http://www.xcelenergy.com/Environment/Doing_Our_Part/Clean_Air_Projects/Minnesota_Metro_Emissions_Reduction_Project.

D. Renewable Energy

Xcel Energy has been a national leader in wind energy for the past 10 years. Our NSP system has 1,867 MW of wind capacity in its portfolio as of today, which is projected to increase to 2,617 MW by 2016. This includes the four new facilities, totaling 750 MW, approved by the Commission in 2013, but does not include the wind additions we are proposing in the Preferred Plan.

We have been able to acquire additional wind capacity, with the federal Production Tax Credit, at a net savings to our customers. The 750 MW approved in 2013 will save our customers $225 million in fuel costs over the life of the projects and avoid 1.5 million tons of CO_2 emissions each year.

Our solar energy portfolio is small today, but projected to grow rapidly with the addition of 187 MW's of utility-scale solar resources by 2017, and additional solar capacity additions under the Preferred Plan. We are on track to meet the mandate of 1.5 percent solar energy by 2020, and our plan will increase solar energy's contribution to 10 percent of NSP retail sales by 2030.

The remainder of our renewable energy portfolio includes more than 600 MW of hydro, biomass, and refuse derived fuel plants.

E. Customer Energy Efficiency

NSP has invested more than $573 million in customer energy efficiency (or DSM) for electricity since 2005, and another approximately $80 million in natural gas DSM. We have achieved cumulative electricity savings of 3.4 billion kWh since 2005 – equivalent to avoiding building about five medium-sized (250 MW each) natural gas power plants – and avoided 2.7 million tons of CO_2 emissions through DSM since 2005. The Company has met or exceeded Minnesota's Conservation Improvement Program (CIP) mandate of 1.5 percent annual electric sales.[65] In 2013, we achieved 1.7 percent savings.

F. Water Management

A reliable water source is essential to producing power at our hydroelectric and thermal generating plants. We carefully manage our water resources by seeking

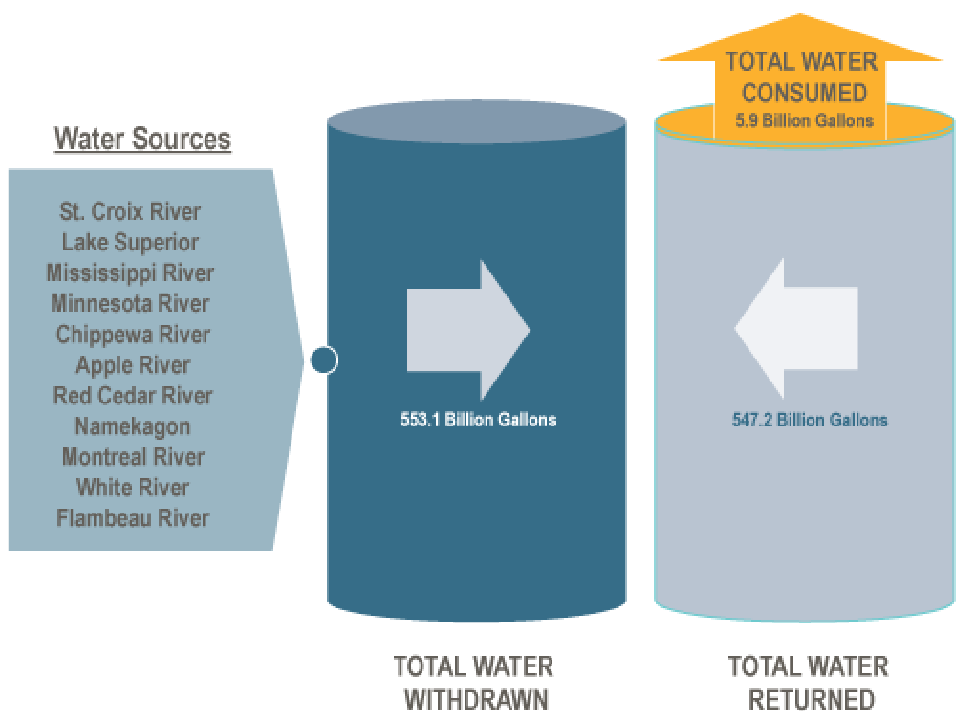
[65] The NGEA established an energy savings goal of 1.5 percent of average retail sales for each electric and gas utility beginning in 2010. *Minn. Stat. §216B.241.*

responsible and secure supply options, working to conserve water where we can and ensuring we maintain water quality, especially where water is used and then returned to the environment. For our hydro plants, water is the fuel that operates plant turbines to produce electricity – an important source of carbon-free electricity.

At thermal plants, we use water to produce steam and to cool equipment. Cooling makes up more than 95 percent of a thermal power plant's water needs, depending on specific plant operations. Thermal plants generally use one of two cooling options that are each uniquely designed for optimal heat transfer to water:

- *Open-loop cooling* is used at most of the NSP system's thermal generating plants. Water is taken from a river, lake or reservoir and used to cool and condense the steam that drives turbines to produce electricity. Water is then returned to the river, lake or reservoir in accordance with all state and federal permits or requirements and in a condition that protects water quality for human use and the environment. Approximately 99 percent of the water used by these plants is returned to the water bodies from which it comes. (See Figure 9 below.) Discharged process water is treated and monitored to ensure we are meeting discharge requirements and to protect the aquatic environment.

Figure 9: NSP Water Supply and Usage



- *Closed-loop cooling* is used at one plant, Sherco. Water runs through towers to cool and condense the steam used to drive turbines to produce electricity. The cooling towers are operated to minimize water withdrawals by reusing water several times, and can also provide recycled water for other plant operations. A portion of the water in closed-loop cooling systems may be returned to the river, lake or reservoir in accordance with all state and federal permits or requirements. Water may also be stored in evaporation ponds.

G. Waste Management

Coal-fueled power plants produce a number of coal combustion byproducts commonly referred to as coal ash. We recycle coal ash whenever possible for beneficial use, such as in concrete products, roadbed material, soil stabilization, engineered-fill material and more.

We use ash from Black Dog in the production of cement or concrete. With the cessation of coal burning at Black Dog, ash production will decline by about 30,000 tons per year of fly ash and 10,000 tons per year of bottom ash.

At Sherco, a small portion of the ash from Unit 3 is used in the manufacture of cement products, and ash is used internally as drainage material within the landfills (replaces sand), road base and construction materials for landfills and ponds. At the King plant, 100 percent of the slag (a type of bottom ash) is being beneficially used to produce roofing materials, sandblasting grit and other products.

We use ash from the Bay Front plant as a soil stabilization and engineered fill material. In 2014 the quantities that were beneficially used were significantly less than in the recent past due to regulatory requirements, but we anticipate resumption of these activities so that in 2015 nearly 100 percent of the Bay Front ash will be utilized.

The Company continues to reduce other wastes as well. From 2010 to 2013, we reduced our production of hazardous wastes, "universal" waste (fluorescent light bulbs, rechargeable batteries, mercury switches, etc.), PCBs (see below), asbestos, scrap metal, used oil and oily materials.

H. PCB Phase-out

For the last several years, the Company has been phasing out transmission and distribution equipment that contains polychlorinated biphenyls (PCBs). The Toxic

Substances Control Act of 1979 defines PCB equipment as equipment having a PCB concentration of 500 parts per million (ppm) or more, while PCB-contaminated equipment has a PCB concentration of 50 to 499 ppm. Our PCB phase-out program focuses on removing all known PCB equipment from our system, including transformers, capacitors and other regulated categories of equipment, and replacing it with non-PCB equipment. Currently NSP-Minnesota and NSP-Wisconsin do not have any known electrical equipment that has a PCB concentration of 500 or more ppm.

In Wisconsin, we are in the final year of a multi-year project to retrofill (remove contaminated oil and replace with clean oil) or replace all known PCB-contaminated electrical equipment within our substations. All known PCB-contaminated equipment in NSP-Wisconsin substations was removed by 2014.

Other phase-out efforts include the replacement of regulated equipment with non-PCB equipment as systems are upgraded. Any regulated equipment removed is immediately disposed of and replaced with non-PCB equipment unless there are extenuating circumstances associated with the design or procurement of the equipment. Xcel Energy personnel are trained on PCB regulations and the proper identification, handling, removal and disposal of this equipment to facilitate phase-out efforts.

I. Legacy Manufactured Gas Plant Projects

In the 1800s up until the mid-1900s, gas was manufactured using coal, oil and petroleum. It was used primarily for heating, cooking and street lighting. The EPA estimates that more than 50,000 manufactured gas plants (MGP) operated in the United States between 1815 and 1960. They were owned by municipalities and corporations, including predecessor companies to today's electric utilities. MGPs produced a variety of wastes and byproducts, including coal tar, some of which were sold for reuse or disposed off-site, and others left at plant sites.

Given the extensive history of our operating companies—going back more than 100 years—Xcel Energy has inherited legacy MGP sites. All the plant facilities were closed and dismantled years ago, and some of the properties where the MGP once operated have been sold. Over the years, Xcel Energy has worked cooperatively with environmental agencies and communities to successfully investigate and/or remediate former MGP sites.

NSP-Wisconsin recently completed two such MGP remediation projects: (1) the former Owen Park MGP site located in Eau Claire, completed in 2013; and (2) the La Crosse MGP site, completed in 2014. All activities were completed in accordance with approved Wisconsin Department of Natural Resources (WDNR) clean-up plans.

NSP-Wisconsin is part of an extensive remediation project underway in Ashland, Wisconsin. During the late 1800s and early 1900s, the lakefront in Ashland was one of the busiest industrial ports in the country. It was the site not only of a legacy MGP, but also the site of lumber and wood treatment facilities, as well as a loading area for railroads. The MGP was operated at the site from 1885 to 1947 and provided gas for street lighting and businesses. Later, the site was used for a city-owned landfill and wastewater treatment plant. NSP-Wisconsin has owned a portion of the Ashland site since 1986.

The site is being cleaned under the supervision of the EPA and the WDNR. The EPA has identified several parties responsible for the cleanup. Under an agreement with the U.S. Department of Justice, the EPA and WDNR, we are conducting phase 1 of the project, which includes remediation of the impacted soils and groundwater at the site. In addition, we have initiated litigation against other potentially responsible parties (PRPs) for cost recovery of their fair share of the cleanup costs. Negotiations among the PRPs, the EPA and the WDNR are ongoing for the second phase of the remediation, which will address impacted sediments at the site in an area of Lake Superior's Chequamegon Bay.

J. Benchmarking our Environmental Performance

The United States electric power sector has generally reduced emissions over time. As of 2013, the industry's CO_2 emissions were approximately 15 percent below 2005 levels.[66] The NSP system compares favorably with this benchmark, having reduced its emissions 23 percent below 2005 levels to date, with a projected 32 percent reduction by 2020 under the Preferred Plan.

Carbon intensity, usually measured in pounds of CO_2 emitted per MWh generated, is also an important measure, since lower-intensity power generation allows electricity demand growth and economic growth to take place with a lower overall increase in CO_2 emissions. The U.S. electric power sector overall has reduced its carbon intensity by approximately 16 percent over the last 10 years. The NSP system compares

[66] See http://www.eia.gov/electricity/data.cfm#elecenv/

favorably, having reduced our CO_2 intensity from owned and purchased power from 1,284 lbs/MWh in 2005 to 1,041 lbs/MWh in 2013, a 19 percent decrease.

The U.S. electric generation fleet is in the midst of an ongoing transformation to a significantly cleaner fleet, due to a combination of factors including:

- The closing of older coal plants;
- The confluence of MATS and other EPA rules;
- Companies taking advantage of new technologies that produce low-cost natural gas to make more electricity;
- Greater efficiency in electricity use;
- Slower economic growth;
- Building new nuclear power plants and increasing the capacity of existing ones; and
- Increased deployment of renewable generation.

The NSP system's fleet transformation since 2005 reflects many of the same factors, as well as concerted efforts with our public utilities commissions and state legislatures to seek proactive retirements and repowering opportunities.