Appendix G
Energy Supply Sector
Policy Recommendations

Summary List of Policy Recommendations

Policy No.	Policy Recommendations	GHG Reductions ($MMtCO_2e$)			Net Present Value 2008–2025 (Million $)	Cost-Effective-ness ($\$/tCO_2e$)	Level of Support
		2015	2025	Total (2008–2025)			
ES-1	Generation Performance Standard	0.0	0.0	0.0	$0.0	$0.0	Majority (16 objections)
ES-3	Efficiency Improvements, Re-powering, and Other Upgrades to Existing Plants	1.8	3.0	33.3	$554.4	$16.7	Unanimous
ES-4	Transmission System Upgrading, Including Reducing Transmission Line and Distribution System Loss	0.2	0.4	3.9	–$92.2	–$26.1	Unanimous
ES-5	Renewable and/or Environmental Portfolio Standard*	*Quantified as a "Recent Action"*					Enacted
ES-6	Nuclear Power Support and Incentives	*Recommended for further study.*					Unanimous
ES-8	Advanced Fossil Fuel Technology Incentives, Support, or Requirements, Including Carbon Capture and Storage	*Recommended for further study.*					Unanimous
ES-10	Voluntary GHG targets	*Not quantified*					Unanimous
ES-12	Distributed Renewable Energy Incentives and/or Barrier Removal	0.021	0.023	0.37	$29.1	$78.1	Unanimous
ES-13	Technology-Based Approaches, Including Research and Development, Fuel Cells, Energy Storage, Distributed Renewable Energy Technologies, etc.	*Not quantified*					Unanimous
	Sector Total After Adjusting for Overlaps	**2.0**	**3.4**	**37.5**	**$462.2**	**$12.3**	
	Reductions From Recent Actions	**12.8**	**20.8**	**225.0**	**$10,116**	**$45.0**	
	Biomass for Electricity	**0.60**	**0.60**	**11.4**	**$285.3**	**$25.0**	
	Metro Emissions Reduction Project	**4.52**	**4.52**	**80.4**	**$2,330**	**$29.0**	
	ES-5: Renewable Energy Standard*	**7.72**	**15.7**	**133.1**	**$7,502**	**$56.4**	
	Sector Total Plus Recent Actions	**14.8**	**24.2**	**262.5**	**$10,578.8**	**$40.3**	

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $\$/tCO_2e$ = dollars per metric ton of carbon dioxide equivalent.

Negative values in the Net Present Value and the Cost-Effectiveness columns represent net cost savings associated with the recommendations. The totals in some columns may not add to the totals shown due to rounding.

All policy totals are relative to the underlying assumption that electricity expansion in Minnesota proceeds with the recently legislated Conservation Improvement Program (CIP), Renewable Energy Standard (RES), and all planned additions, including the Mesaba and Big Stone 2 stations.

*The RES considered here is based on the RES requirements included in the Next Generation Energy Act of 2007; therefore, the emission reductions and costs estimated are included under "recent actions."

Note: A number of MCCAG members have raised concerns about the cost assumptions associated with wind power and believe the costs are too high. A lower wind cost assumption would lower the cost estimates for the Renewable Energy Standard (ES-5) and for the Cap and Trade analyses. Future analyses should re-examine the wind cost estimates.

ES-1. Generation Performance Standard

Note: *At its last meeting, the MCCAG decided that this option would not apply to the planned Big Stone 2 and Mesaba. Therefore, no benefits or costs are ascribed to this option. Hence, the results presented here—reflecting deliberations about the analysis by the ES Technical Work Group that took place over the course of the process—are for information purposes only.*

Policy Description

A generation performance standard (GPS) is a mandate that requires entities that deliver electricity (load-serving entities [LSEs]) to acquire electricity, or power plant developers to build and operate new base-load generation, with a per-unit emission rate below a specified mandatory standard.

Policy Design

Goals: The general goal of the policy is to prevent utilities from making long-term investments in high-carbon-generation technology. In particular, the GPS would prevent utilities from making a long-term financial commitment to base-load generation plants with carbon dioxide (CO_2) emissions in excess of 1,100 pounds of CO_2 per megawatt-hour (MWh).

A long-term financial commitment would be defined to include either a new ownership investment in base-load generation or a new contract with a term of 5 or more years that includes procurement of base-load generation.

The GPS would be designed to harmonize with policies that seek to reduce greenhouse gas (GHG) emissions by promoting greater use of biomass and combined heat and power (CHP). For purposes of compliance with the GPS, the CO_2 emissions attributed to biomass energy would be net emissions based on a full fuel-cycle analysis. For base-load projects that are part of a CHP project, the GPS would be raised to 1,300 pounds of CO_2/MWh.

Timing: Two alternative onset dates for the GPS: (1) an immediate onset date that would apply to all base-load projects not already in operation, and (2) a delayed onset date that would exclude base-load facilities currently under consideration in proceedings before the Minnesota Public Utilities Commission (MPUC). The ongoing need for a GPS would be reviewed after the implementation of a cap-and-trade system.

Parties Involved: The program would apply to any state LSE making long-term financial commitments to base-load power.

Implementation Mechanisms

Implementation would be through the MPUC, which would review all long-term financial commitments to base-load generation made by Minnesota utilities to ensure compliance with the GPS.

Related Policies/Programs in Place

None.

Type(s) of GHG Reductions

Reduces CO_2 emissions from fossil-fuel electric generators, and promotes low-carbon alternatives to fossil fuel generators.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources:

- U.S. Department of Energy (DOE), Energy Information Administration (EIA), Office of Energy Statistics, *Assumptions to the Annual Energy Outlook 2007*, DOE/EIA-0554, April 2007. Available at: www.eia.doe.gov/oiaf/aeo/assumption/pdf/introduction_tables.pdf
- U.S. DOE, National Energy Technology Laboratory, "Volume 1: Bituminous Coal and Natural Gas to Electricity. Final Report," in *Cost and Performance Baseline for Fossil Energy Plants*, DOE/NETL-2007/1281, August 2007. Available at: http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf
- Plant-specific Minnesota capacity addition data are based on U.S. DOE, EIA, Office of Energy Statistics, "Electric Power Annual 2006—State Data Tables: 1990–2006 Net Generation by State by Type of Producer of Energy Source," EIA-906. Available at: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html

Quantification Methods:

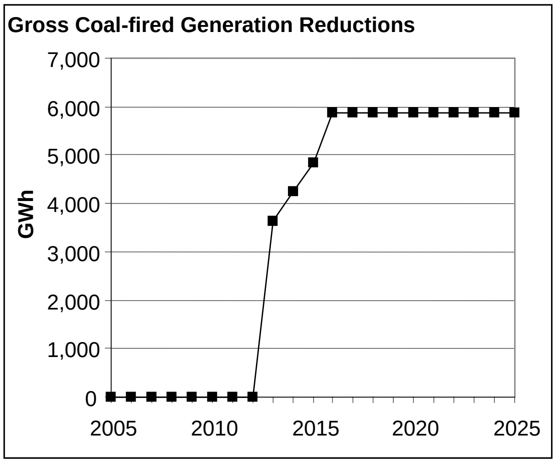
This policy is a mandate requiring entities that deliver electricity to acquire electricity, or power plant developers to build and operate new base-load generation, with a per-unit emission rate below a specified mandatory standard (1,110 pounds [lb] of CO_2/MWh for power stations, and 1,300 lb of CO_2/MWh for CHP stations). The key assumptions for the analysis of this policy are as follows:

- The start year for the policy is 2013.
- Two cases were analyzed:
  - *The GPS affects only new unplanned capacity*. This case refers to onset date (2) under the Timing subsection of the Policy Design section, above. In this case, the implementation of the GPS in Minnesota has no GHG reduction benefits, as no unplanned capacity additions exceed the emission intensity threshold.
  - *The GPS affects all new capacity, planned and unplanned.* This case refers to (1) under the Timing subsection of the Policy Design section, above. It is examined below.

Case 2: The GPS affects all new capacity, planned and unplanned

The application of the GPS leads to the elimination of new planned coal capacity in Minnesota. No replacement power is needed because electricity demand can be met by the combination of existing Minnesota generation and forecasted levels of imports. Figure G-1 summarizes the impact of this policy. The curve represents the total annual reductions associated with the elimination of planned coal-fired generation for Minnesota.

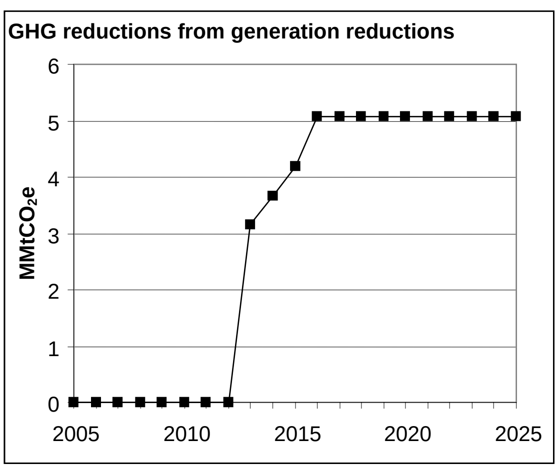
Figure G-1. Minnesota planned coal-fired generation



GWh = gigawatt-hours.

Figure G-2 summarizes the impact of this policy on CO_2-equivalent (CO_2e) emission reductions. The curve represents the annual CO_2e reductions associated with the elimination of new planned coal-fired generation. The annual emission reductions in 2015 and 2025 are 4.1 and 5.1 $MMtCO_2e$, respectively. The cumulative emission reductions over the 2013–2025 period are 61.8 $MMtCO_2e$.

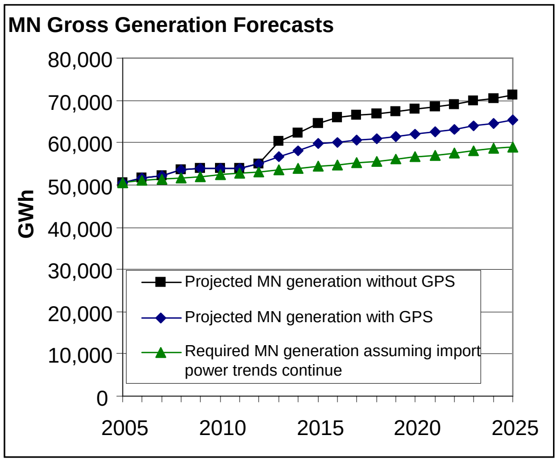
Figure G-2. Annual CO_2e reductions from elimination of planned coal-fired generation in Minnesota



GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

Figure G-3 summarizes the impact of the option on the need for replacement power. The middle curve is the projected gross generation in Minnesota after the implementation of the GPS. The lower curve is the "required" Minnesota gross generation under the assumption that the share of imported power to total power evident in 2005 continues through the end of the forecast period. As projected gross generation in Minnesota after implementation of the GPS always exceeds "required" Minnesota gross generation, no replacement power is needed.

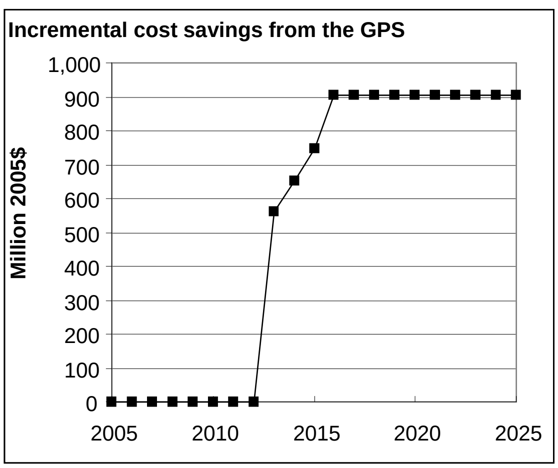
Figure G-3. Projected and required gross generation in Minnesota



GWh = gigawatt-hours; GPS = generation performance standard.

Capital, transmission, variable operations and maintenance (O&M) and fixed O&M costs and fuel savings are associated with the planned capacity additions that would be built were the GPS not in effect. The levelized capital costs for a pulverized coal and integrated gasification combined-cycle (IGCC) station coming online in 2005 were assumed to be $69/MWh and $84/MWh, respectively, and were escalated by a factor of 1.29 to account for real escalation assumptions. The annual product of real levelized costs and displaced generation is an estimate of the annual cost savings. This is summarized in Figure G-4. The net present value (NPV) of these annual costs is –$7.4 billion over the 2013–2025 period (2005$).

Figure G-4. Incremental cost savings from the GPS



GPS = generation performance standard.

Cost-effectiveness was calculated as the quotient of the NPV and cumulative GHG emission reductions, –$120/t$CO_2$e reduced (2005$) (i.e., –$7.4 billion divided by 61.8 MMt and multiplied by a conversion factor of 1,000).

The need for power to replace generation from capacity affected by the GPS should be subjected to an assessment of whether such power is needed, given projected Minnesota electricity sales demand. If needed, replacement power will come from out-of-state suppliers, with a mix of 75% natural gas-fired sources and the 25% balance from wind power.

Key Assumptions: See Annex 1.

Key Uncertainties

The GPS would expand MPUC oversight to certain transactions or projects not currently subject to MPUC review under the Certificate of Need or other laws, but only for the purpose of screening those transactions or projects for compliance with the GPS. It is uncertain how many additional projects would be subject to MPUC approval. It is expected that the GPS approval process would be far more streamlined than the typical Certificate of Need review process.

Other uncertainties include (1) the need to consider whether a GPS is necessary if the state enacts a cap-and-trade program covering electric generation, (2) whether the 1,300 lb/MWh threshold is set at the right level to encourage efficient CHP installations, (3) whether natural gas peaker units can reasonably be included in the policy in addition to base-load generation, and (4) whether offsets would be allowed for compliance flexibility.

Additional Benefits and Costs

Reduced air pollution.

Feasibility Issues

The feasibility of a GPS would need to be examined if the state enacts a cap-and-trade program covering electric generation.

Status of Group Approval

Complete.

Level of Group Support

Majority (16 objections). The Minnesota Climate Change Advisory Group (MCCAG) would like the Center for Climate Strategies to analyze the impact of two different approaches regarding the renewal of contracts procuring base-load power from existing units—one approach that includes such contracts (if they are for 5 or more years) and one that excludes them.

Barriers to Consensus

The objections were to the exclusion from the GPS requirement of all planned capacity additions that are already at some stage in the regulatory process in Minnesota and that will not meet the GPS threshold.

ES-3. Efficiency Improvements, Repowering, and Other Upgrades to Existing Plants

Note: *At an earlier meeting, the MCCAG decided that this option would proceed on the basis of 8% biomass co-firing at coal-fired power stations. Subsequent to that MCCAG decision, the TWG took up the matter and decided that a 1% biomass co-firing matter was more appropriate. The originally approved level is reported in the energy supply chapter. Hence, the results presented here for the primary analysis—reflecting the 1% biomass co-firing level—are for information purposes only.*

Policy Description

This policy promotes the identification and pursuit of cost-effective emission reductions from existing generating units by improving their operating efficiency, adding biomass or other fuel changes, or adding carbon capture technology. This policy complements a GPS (which applies to new plants and new units) by applying to existing units. Given that CO_2 emissions have not previously been the focus of state regulation, and given that existing units have not been the focus of resource planning, it is expected that there are as yet unidentified opportunities to reduce emissions from existing facilities that will be cost-effective, particularly once CO_2 limits are in place. In time, this policy will result in the identification of a portfolio of technological options for reducing GHG emissions and will allow state utilities to share the opportunities they have identified.

The MCCAG recommends that the Center for Climate Strategies investigate the impact of policies that

- Require utilities to evaluate their existing generating units for opportunities to improve their emissions profile through efficiency improvements, the addition of biomass or other fuel changes, or the addition of carbon capture technology. This evaluation would be part of an overall plan identifying cost-effective options for reducing system CO_2 emissions on a short-term and long-term basis.
- Require utilities to pursue cost-effective options for reducing their emissions profile through measures identified above.
- Create financial incentives that reward such emission reductions.

The term “cost-effective” would be defined by some objective measure, such as cost per ton of CO_2e.

Policy Design

Goals: The policy would be intended to ensure that utilities undertake analyses of their operating systems to identify and pursue cost-effective opportunities to reduce emissions.

Timing: This policy would become applicable as soon as possible.

Parties Involved: It would cover Minnesota load-serving entities.

Implementation Mechanisms

The planning and emission reduction requirements would be implemented through the integrated resource planning (IRP) process already implemented by MPUC.

Related Policies/Programs in Place

Existing IRP requirements (see above). The requirement is an important counterpart to a GPS, which covers only new financial commitments. It complements a cap-and-trade policy by ensuring that utilities pursue cost-effective potential emission reductions, rather than the more obvious option of purchasing emission allowances (with the projected price of allowances being a key part of the definition of cost-effective reductions).

Type(s) of GHG Reductions

Avoided emissions from fossil-fuel generation.

Estimated GHG Reductions and Net Costs or Cost Savings

- U.S. DOE, EIA, Office of Energy Statistics, *Assumptions to the Annual Energy Outlook 2007*, DOE/EIA-0554, April 2007. Available at: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf
- U.S. DOE, National Energy Technology Laboratory, "Volume 1: Bituminous Coal and Natural Gas to Electricity. Final Report," In *Cost and Performance Baseline for Fossil Energy Plants*, DOE/NETL-2007/1281, August 2007. Available at: http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf
- U.S. DOE, EIA, Office of Energy Statistics, "Electric Power Annual 2006—State Data Tables. 1990–2006 Net Generation by State by Type of Producer of Energy Source," EIA-906. Available at: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html

Quantification Methods:

This policy promotes the identification and pursuit of cost-effective emission reductions from existing generating units by improving their operating efficiency, adding biomass or other fuel changes, or adding carbon capture technology. It has been modeled as a biomass co-firing policy with a sensitivity analysis on a natural gas repowering component.

Primary Analysis: Biomass Co-Firing at Minnesota Coal Stations

The key assumptions for the analysis of this biomass co-firing policy are as follows:

- The start year is 2013.
- Biomass, harvested sustainably, represents a maximum of 1% of fuel combusted annually at pulverized coal power stations.
- The ramp-up period for full utilization of biomass in co-fired coal stations is 5 years.
- Wood wastes and forest residues are the major form of biomass to be used, at a flat price of $2.5/million British thermal units (MMBtu) (2005$).

The impact of this policy on biomass supplies in Minnesota should be evaluated and supply and demand effects should be reflected in the price of biomass.

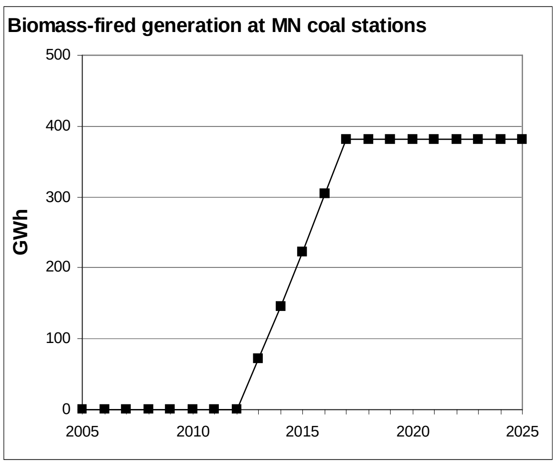
Sensitivity Analysis: Natural Gas Repowering of an Existing 600-MW Coal Station in Minnesota

The key assumptions for this sensitivity analysis of the biomass co-firing policy are as follows:

- The start year is 2013.
- The coal station would be repowered with a natural gas combined-cycle unit (NGCC).

Figure G-5 presents the total generation associated with co-fired biomass in Minnesota.

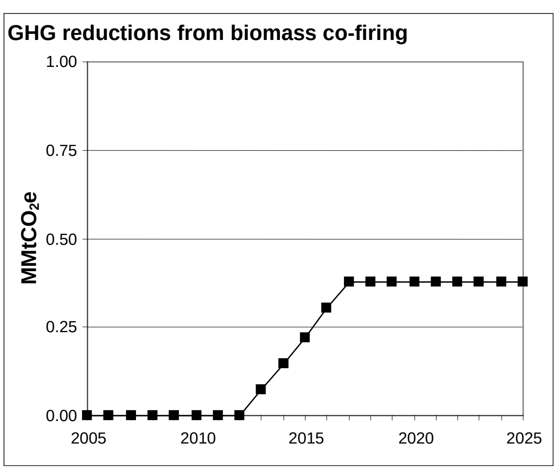
Figure G-5. Projected generation of co-fired biomass at Minnesota coal stations



GWh = gigawatt-hours.

Figure G-6 presents the annual CO_2e reductions associated with biomass co-firing. The annual emission reductions in 2015 and 2025 are 0.2 and 0.4 $MMtCO_2e$, respectively. The cumulative emission reductions over the 2005–2025 forecast period are 4.2 $MMtCO_2e$.

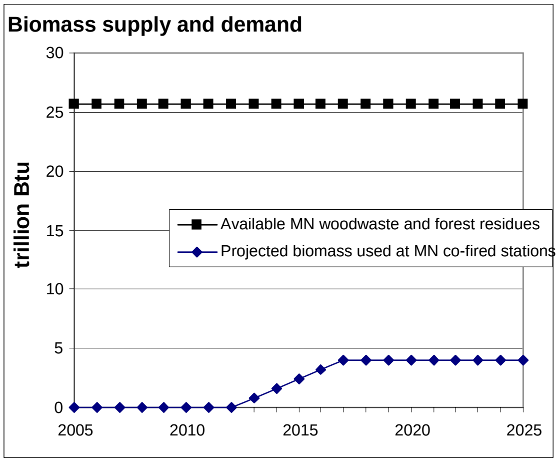
Figure G-6. Projected GHG reductions from biomass co-firing in Minnesota



GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

Figure G-7 summarizes the impact of the policy on demand for and supply of wood wastes and forest residues. The projected biomass used at Minnesota coal stations would not exceed available Minnesota supply in any year.

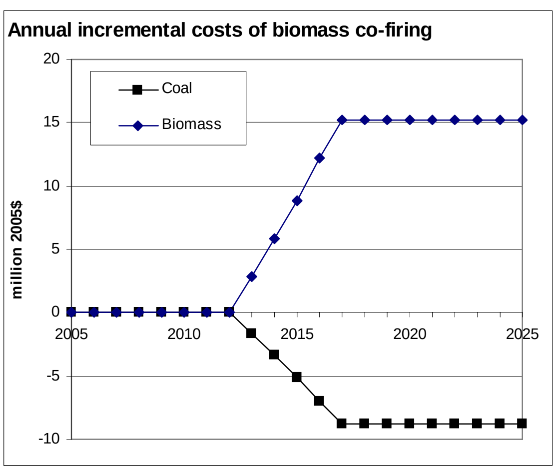
Figure G-7. Impact of biomass co-firing on biomass supply and demand in Minnesota



Btu = British thermal units.

There are annual incremental costs from biomass associated with the fuel cost (no incremental O&M costs were assumed) and incremental savings from coal associated with lower fuel costs, as summarized in Figure G-8, below. The NPV of these annual costs is $0.05 billion over the 2013–2025 period (2005$).

Figure G-8. Annual incremental costs of biomass co-firing in Minnesota



The cost-effectiveness of the policy was calculated for Reference Scenario #1 as the quotient of the NPV and cumulative GHG emission reductions, or $12/$tCO_2e$ reduced (2005$) (i.e., $0.05 billion divided by 4.2 MMt and multiplied by a conversion factor of 1,000).

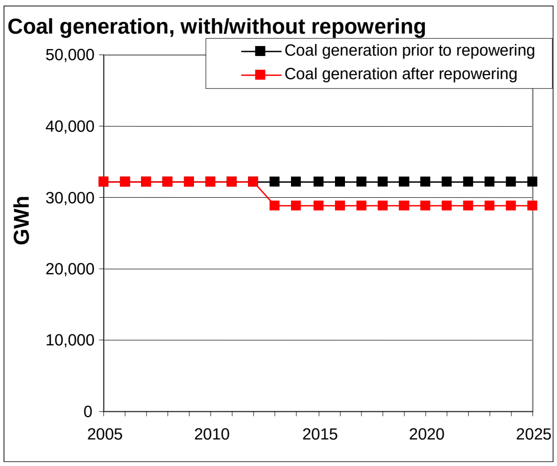
Sensitivity Analysis: Natural Gas Repowering of an Existing 600-MW Coal Station in Minnesota

The key assumptions for this sensitivity analysis of the biomass co-firing policy are as follows:

- The start year is 2013.
- The coal station would be repowered with an NGCC unit.

Figure G-9 presents the total generation associated with existing coal stations, with and without the repowered facility in Minnesota.

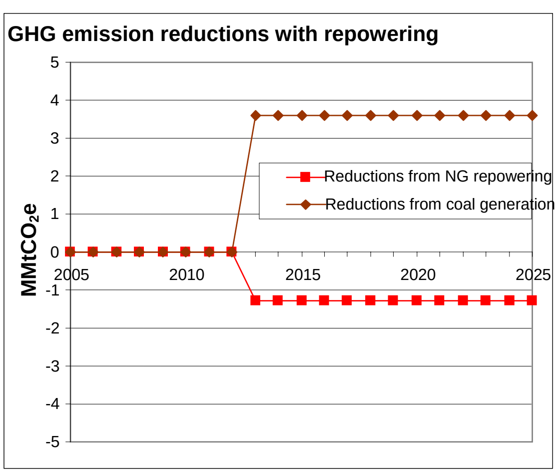
Figure G-9. Impact on coal generation with and without repowering



GWh = gigawatt-hours.

Figure G-10 presents the annual CO_2e reductions associated with displaced coal generation and the incremental natural gas-fired generation. The net annual emission reductions are 2.3 $MMtCO_2e$ in 2015 and 2025. The net cumulative emission reduction over the 2013–2025 forecast period is 29.9 $MMtCO_2e$.

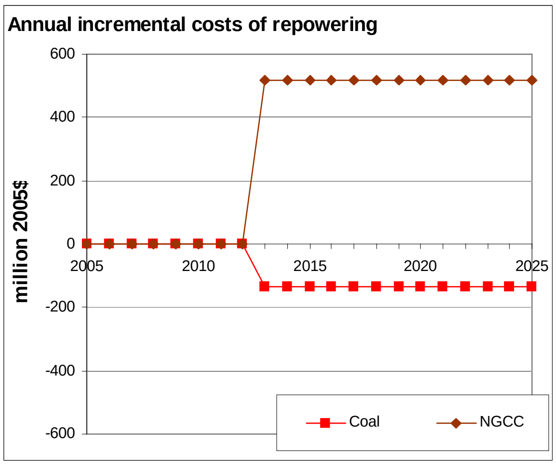
Figure G-10. GHG emission reductions from repowering



MMtCO_2e = million metric tons of carbon dioxide equivalent; NG = natural gas.

There are incremental capital, O&M, and fuel costs from the NGCC unit and incremental fuel and O&M savings from coal, as summarized in Figure G-11. The coal station was assumed to be fully depreciated. The NPV of these annual costs is $3.6 billion over the 2013–2025 period (2005$).

Figure G-11. Annual incremental costs of repowering



NGCC = natural gas combined-cycle.

The cost-effectiveness of this policy was calculated for Reference Scenario #1 as the quotient of the NPV and cumulative GHG emission reductions, or \$120/tCO_2e reduced (2005\$) (i.e., \$3.6 billion divided by 29.9 MMt and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 1.

Key Uncertainties

The following uncertainties were identified: (1) whether and how the new source review provisions of the Clean Air Act will affect the promotion of plant upgrades, (2) how this policy relates to the GPS proposal, (3) how the term "cost-effective" should be defined, and (4) how this policy relates to the cap-and-trade policy recommendations.

Additional Benefits and Costs

Reduced air pollution associated with displaced coal generation.

Feasibility Issues

There are technical feasibility issues regarding the degree to which biomass co-firing would lead to the risk of wear, corrosion, slagging, and fouling in the combustion system.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

ES-4. Transmission System Upgrading, Including Reducing Transmission Line and Distribution System Loss

Policy Description

Measures to improve transmission systems to reduce bottlenecks and enhance throughput may be required to meet long-term electricity demands and improve the efficiency of operations system-wide. Opportunities may exist to substantially increase transmission line carrying capacity through the implementation of new construction and retrofit activities on the transmission grid, including incorporating advanced composite conductor technologies, capacitance technologies, and grid management software.

Siting new transmission lines can be a difficult process due to the regulatory time and cost of line construction, including new right-of-way acquisition. Siting new lines also increases carbon emissions, and clearing a right of way can have negative effects on habitat, land use and enjoyment, and property value.

Measures supporting this policy could provide incentives to utilities to upgrade transmission systems and reduce barriers to Certificate of Need filings for new and existing transmission lines. Future development of renewable energy facilities may require the addition of new or improved transmission lines that must be seamlessly integrated into the transmission grid. Measures facilitating development of these projects can be a critical part of Minnesota's renewable energy future.

Several energy efficiency measures can be implemented to reduce transmission and distribution line losses of electricity. Utilities use a variety of components throughout the transmission and distribution system to manage losses. Increasing the efficiency of these components can further reduce losses and associated GHG emissions. For example, Vermont offers utilities a rebate to encourage the installation of energy-efficient transformers. Regulations, incentives, and/or support programs can be applied to achieve greater efficiency of transmission and distribution system components.

Any reduction of leaks during production, processing, and distribution on natural gas systems avoids methane emissions to the atmosphere and prevents the waste of valuable commodity.

Policy Design

Goals:

- Provide financial incentives for implementing smart energy (computer) technologies.
- Assess the effectiveness of the streamlining efforts enacted in 2005 regarding siting and routing of transmission lines to determine what additional streamlining measures should be enacted.
- Allow financial recovery credit for related efficiency savings resulting in GHG reductions, even if it is not shown to be cost-effective from a customer standpoint, whether it results from upgrading transformers or re-conductoring (replacing inefficient conductors).

- Improve individual line and grid efficiencies with incentives to reduce line losses.
- Provide financial research and development (R&D) support to identify new technologies, including improved leak surveying of natural gas systems and upgrading natural gas controllers that operate and vent natural gas.

Timing: The program should be launched in 2010. Reductions should be achieved over the 2010–2025 time period.

Parties Involved: Electric utilities, gas utilities, independent system operators, gas pipeline companies.

Implementation Mechanisms

As noted above.

Related Policies/Programs in Place

Renewable energy objective, 25% of electricity sales by 2025.

Type(s) of GHG Reductions

Reduced CO_2 from fossil-fuel electricity generation, avoided emissions from increased siting of renewable energy facilities, and avoided methane emissions from leaks in natural gas distribution.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources:

- Minnesota inventory provided by P. Ciborowski (Minnesota Pollution Control Agency) to R. Strait (Center for Climate Strategies).
- U.S. Environmental Protection Agency (EPA), *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2005*, USEPA #430-R-07-002, April 2007. Available at: http://www.epa.gov/climatechange/emissions/downloads06/07CR.pdf
- Annex 3 of *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2005*, USEPA #430-R-07-002, April 2007. Available at: http://www.epa.gov/climatechange/emissions/downloads06/07Annex3.pdf
- U.S. EPA, Office of Air and Radiation, "Directed Inspection and Maintenance at Compressor Stations," *Lessons Learned From Natural Gas STAR Partners*, EPA430-B-03-008, October 2003. Available at: http://www.epa.gov/gasstar/pdf/lessons/ll_dimcompstat.pdf
- U.S. EPA, Office of Air and Radiation. "Reducing Methane Emissions From Compressor Rod Packing Systems." *Lessons Learned From Natural Gas STAR Partners*. EPA430-B-03-011, Washington, DC, July 2003. Available at: http://epa.gov/gasstar/pdf/lessons/ll_rodpack.pdf
- U.S. EPA, Office of Air and Radiation. "Replacing Wet Seals With Dry seals in Centrifugal Compressors." *Lessons Learned From Natural Gas STAR Partners*. EPA430-B-03-012, Washington, DC, October 2003. Available at: http://www.epa.gov/gasstar/pdf/lessons/ll_wetseals.pdf

- U.S. EPA, Office of Air and Radiation. "Directed Inspection and Maintenance at Gate Stations and Surface Facilities." *Lessons Learned From Natural Gas STAR Partners*. EPA430-B-03-007, Washington, DC, November 2003. Available at: http://www.epa.gov/gasstar/pdf/lessons/ll_dimgatestat.pdf
- U.S. EPA. "Convert Engine Starting to Nitrogen." PRO Fact Sheet No. 101. Washington, DC, September 2004. Available at: http://www.epa.gov/gasstar/pdf/pro_pdfs_eng/convertenginestartingtonitrogen.pdf
- U.S. EPA, Office of Air and Radiation. "Pneumatic Devices." *Lessons Learned From Natural Gas STAR Partners*. Producers Technology Transfer Workshop. Midland, TX: Occidental Oil and Gas and EPA Natural Gas Star Program, June 8, 2006. Available at: http://www.epa.gov/gasstar/workshops/midland-6806/gremillion2.pdf
- U.S. EPA, Office of Air and Radiation. "Using Pipeline Pump-Down Techniques to Lower Gas Line Pressure Before Maintenance." *Lessons Learned From Natural Gas STAR Partners*. EPA430-B-04-002, Washington, DC, February 2004. Available at: http://www.epa.gov/gasstar/pdf/lessons/ll_pipeline.pdf

Quantification Methods:

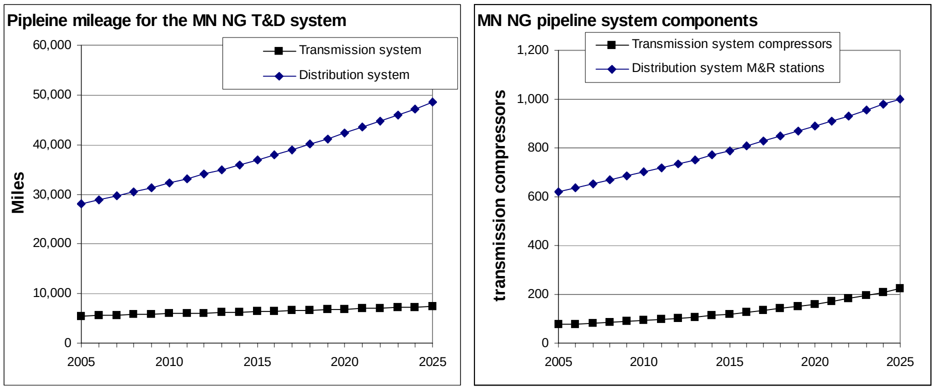
This policy would improve electricity transmission systems to reduce bottlenecks, enhance throughput, and improve the efficiency of operations system-wide. It also targets reduction of leaks in natural gas pipelines to avoid methane emissions to the atmosphere and prevent the waste of valuable product.

The policy has been modeled thus far as an upgrade to the natural gas transmission and distribution pipeline system. This is due to the fact that the costs associated with upgrades to the electric transmission and distribution system remain speculative and are unquantified. The following assumptions were made regarding the analysis of upgrading the natural gas transmission and distribution system:

- The start year for the policy is 2010.
- The methane reduction target for the Minnesota natural gas transmission system is 25% of projected emissions in 2025 in the Reference Case.
- The methane reduction target for the Minnesota natural gas distribution system is 15% of projected emissions in 2025 in the Reference Case.
- The ramp-up period for full implementation of methane leak mitigation for the Minnesota natural gas transmission system is 10 years.
- The ramp-up period for full implementation of methane leak mitigation for the Minnesota natural gas distribution system is 8 years.

Figure G-12 summarizes the total projected mileage for both the Minnesota natural gas transmission and distribution system (left), and the total projected number of compressors for the transmission system and the number of metering and regulating (M&R) stations for the distribution system (right).

Figure G-12. Projected mileage for the natural gas transmission and distribution system, and components for the pipeline system



NG = natural gas; T&D = transmission and distribution; M&R = metering and regulating.

For the Minnesota natural gas transmission system, several mitigation options were analyzed for their collective impact on reducing methane leaks, as follows:

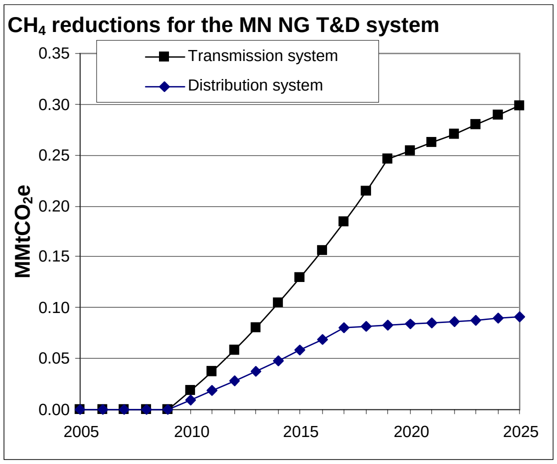
- Implementing directed inspection and maintenance at compressor stations,
- Reducing methane emissions from compressor rod packing systems,
- Replacing wet seals with dry seals in centrifugal compressors,
- Implementing directed inspection and maintenance at gate stations and surface facilities,
- Converting to compressed nitrogen as engine startup fuel for pumps and compressors
- Retrofitting pneumatic devices with low-bleed kits, and
- Using pipeline pump-down techniques to lower gas line pressure before maintenance.

For the Minnesota natural gas distribution system, one mitigation option was analyzed for its impact on reducing methane leaks, as follows:

- Implementing directed inspection and maintenance at gate stations and surface facilities.

Figure G-13 summarizes the impact of the collective policies on CO_2e emission reductions. The curves represents the annual CO_2e reductions associated with avoiding methane leaks in the Minnesota natural gas pipeline system. The annual emission reductions in 2015 and 2025 are 0.2 and 0.4 MMtCO_2e, respectively. The cumulative emission reductions over the 2010–2025 forecast period are 3.9 MMtCO_2e.

Figure G-13. GHG emission reductions from the natural gas transmission and distribution system



NG = natural gas; T&D = transmission and distribution; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

The incremental annual costs from biomass associated with capital improvements, O&M, and fuel for each of the policies were considered, along with the incremental savings associated with the value of the natural gas emissions avoided. The NPV of these annual costs is –$0.093 billion over the 2010–2025 period (2005$).

The cost-effectiveness of the policy was calculated as the quotient of the NPV and cumulative GHG emission reductions, or –$26/$tCO_2e$ reduced (2005$) (i.e., –$0.093 billion divided by 3.9 MMt and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 1.

Key Uncertainties

The policy will need to be integrated with the existing Cap-X 2020 program.

Additional Benefits and Costs

None.

Feasibility Issues

The policy recommends practices that are well within technical capabilities of natural gas pipeline operation and maintenance activities.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

ES-5. Renewable and/or Environmental Portfolio Standard

Policy Description

A portfolio standard policy can require a sector (electricity supply, transportation, industrial/manufacturing, and commercial/residential buildings) to provide for lower GHG emissions from energy use or operations by targeting an increased amount of lower emission activities in the aggregate by a target date. A renewable portfolio standard (RPS) requires utilities and other load-serving entities to supply a certain, generally fixed, percentage of electricity from eligible (e.g., low-GHG-emitting) renewable energy sources. An environmental portfolio standard (EPS) expands portfolio requirements to include energy production with technologies that are not now classified as renewable but are viewed as releasing less GHG emissions than conventional energy production. These measures can include energy efficiency improvements or other GHG emission-reducing technologies (such as CHP) as an eligible resource.

About 20 states currently have an RPS in place, while only a handful have implemented an EPS. In some cases, utilities can also meet their portfolio requirements by purchasing Renewable Energy Certificates from eligible renewable energy projects or carbon offsets from certified sources.

Minnesota has adopted a renewable energy standard (RES) of 25% by 2025.

Policy Design

Goals:

- Evaluate what GHG reductions will be realized by Minnesota's (RES) up through the 2025 time frame.
- Evaluate what GHG reductions may be realized should Minnesota increase portfolio requirements beyond the 2025 time frame requirement in existing law through 2050. The study should include an analysis of the adequacy of transmission capacity.
- Evaluate the use of hydropower, biomass, and offsets in the context of CO_2 benefits to meet RES/EPS requirements as defined in Minnesota state statutes.
- Increase R&D funding for renewable and environmentally friendly (low-CO_2-emitting) energy that reduces GHG emissions (e.g., the University of Minnesota's Initiative for Renewable Energy and the Environment).
- Evaluate performance standards (e.g., carbon-intensity targets) for renewable and environmentally friendly energy use by residential, commercial, and industrial entities.

Timing: Assume that current legislation will cover the time period from the present to 2025. Legislation should be enacted by 2009 to allow time for planning to meet any new standards. Funding for renewable and environmentally friendly energy R&D should begin as soon as practicable.

Parties Involved: Midwest Renewable Energy Tracking System, MPUC, Minnesota State Legislature, Minnesota Department of Commerce.

Implementation Mechanisms

Require future legislation covering 2025–2050 for the renewable requirement, while

- Performing an evaluation of expanding the RPS requirement once the dates in existing law have been reached,
- Providing utilities with adequate lead time, and
- Reevaluating expansion of what qualifies as renewable and/or environmental sources.

Increase funding by 2009 for R&D relative to new and improved technology advancements.

Institute a renewable energy credit trading program (Minnesota Statutes 2007, Chapter 216B.1691).

Explore creation of energy-intensity targets, such as carbon-intensity targets, as a means for broadening the application of portfolio standards to all Minnesota sectors.

Related Policies/Programs in Place

The state has adopted a 25% renewable energy goal by 2025.

Minnesota Statutes 2007, Chapter 216.

Type(s) of GHG Reductions

Reductions in all GHG emissions from energy production and GHG emissions associated with process operational emissions and energy consumption.

Estimated GHG Reductions and Net Costs or Cost Savings

- U.S. DOE, EIA, Office of Energy Statistics, *Assumptions to the Annual Energy Outlook 2007*, DOE/EIA-0554, April 2007. Available at: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf
- U.S. DOE, National Energy Technology Laboratory, "Volume 1: Bituminous Coal and Natural Gas to Electricity. Final Report," In *Cost and Performance Baseline for Fossil Energy Plants*, DOE/NETL-2007/1281, August 2007. Available at: http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf
- U.S. DOE, EIA, Office of Energy Statistics, "1990–2006 U.S. Electric Power Industry Estimated Emissions by State," EIA-906. Available at: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html
- Minnesota State Legislature, Next Generation Energy Act of 2007, Article 5, Section 2, lines 41.2 and following.

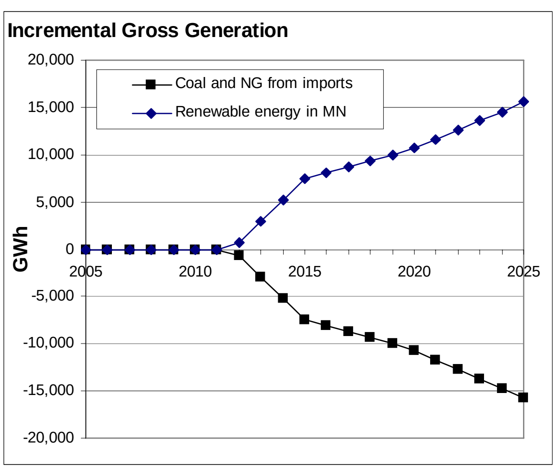
Quantification Methods:
This policy requires that utilities and other load-serving entities to supply a certain, generally fixed, percentage of electricity from eligible (e.g., low-GHG-emitting) renewable energy sources. The current Minnesota statute through 2025—25% renewable energy as a percentage of sales—was modeled.

The key assumptions for the analysis of this policy are as follows:

- The start year is 2011.
- Incremental renewable energy generation associated with the implementation of the RES in Minnesota would not displace generation from any generation resources in Minnesota.
- Incremental renewable energy generation in Minnesota would first displace natural gas-fired generation (combustion turbines) associated with imports and then coal-fired generation from imports.
- Roughly 25% of the power generation backed down from out-of-state coal facilities would be fully depreciated (i.e., fixed O&M, variable O&M, and fuel costs only—no capacity-related costs). The capital costs of non-depreciated units were assumed to be one-third of 2005 costs.

Figure G-14 summarizes the impacts of the RES on gross generation in Minnesota. The upper curve represents the total incremental generation associated with the RES in Minnesota and the lower curve represents incremental displaced coal- and natural gas-fired generation outside Minnesota.

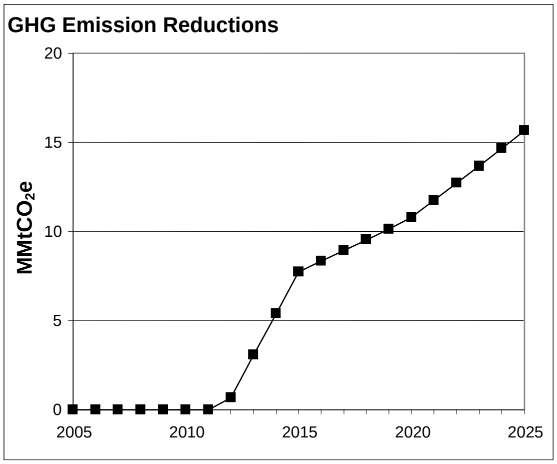
Figure G-14. Impacts of an RES on incremental gross generation in Minnesota



NG = natural gas; GWh = gigawatt-hours.

Figure G-15 presents the projected GHG reductions from the RES. The annual CO_2e emission reductions in 2015 and 2025 are 7.7 and 15.7 $MMtCO_2e$, respectively. The cumulative emission reductions over the 2011–2025 forecast period are 133.1 $MMtCO_2e$.

Figure G-15. Projected GHG emission reductions from the RES



GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

There are cost savings associated with avoided fuel and O&M at coal- and natural gas-fired facilities located outside Minnesota, and a portion of their capital costs. The levelized capital costs for imported coal- and natural gas-fired energy was assumed to be $92/MWh and $217/MWh, respectively (2005$). The incremental costs associated with the RES include capital costs, transmission costs, variable O&M costs, fixed O&M costs, and fuel costs. The annual product of real levelized costs and displaced generation is an estimate of the annual costs. The NPV of these annual costs is $4.7 billion over the 2011–2025 period (2005$).

The cost-effectiveness of this policy was calculated as the quotient of the NPV and cumulative GHG emission reductions, or \$35.5/tCO_2e reduced (2005$) (i.e., $4.7 billion divided by 133.1 MMt and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 1.

Key Uncertainties

The costs of renewable energy technologies, the price forecast for natural gas and coal delivered to regional power stations, and the portion of backed-down generation that is fully depreciated.

Additional Benefits and Costs

Improved air quality associated with displaced coal- and natural gas-fired generation.

Feasibility Issues

System integration of intermittent power generation; adequacy of electric transmission capacity.

Status of Group Approval

Complete.

Level of Group Support

Enacted. Note that the RES is included in existing Minnesota law and, therefore, is considered an existing action. The MCCAG included this policy as a priority for analysis in order to estimate the emission reductions and costs associated with the existing RES.

Barriers to Consensus

Not applicable.

ES-6. Nuclear Power Support and Incentives

Note: At its last meeting, the MCCAG decided that this option required further study and, therefore, that no benefits or costs would be ascribed to it. Hence, the results presented here—reflecting deliberations about the analysis by the ES Technical Work Group that took place over the course of the process—are for information purposes only.

Policy Description

The role of nuclear power in a GHG-constrained energy supply system is both important and controversial. Today, nuclear power plants provide about 20% of electric power both nationally and in Minnesota. The role of both existing and new units needs to be considered for a comprehensive climate change policy process.

This policy provides support and incentives for life extension at existing nuclear power plants and for study of potential new nuclear power plants in Minnesota.

Policy Design

Goals: The policy is intended to ensure that utilities undertake analyses of their operating systems to identify and pursue cost-effective opportunities to reduce emissions with an emphasis on nuclear power through

- Life extension,
- Capacity upgrades,
- Purchase of imported nuclear power, and
- Potential new nuclear power plants. *This is the specific option proposed; i.e., a study examining the issues regarding one 1,100 MW unit installed in Minnesota in the post-2025 period*.

Timing: This policy should be implemented as soon as possible.

Parties Involved: It would cover Minnesota load-serving entities.

Implementation Mechanisms

The planning requirements would be implemented through the IRP process already implemented by MPUC. Thorough consideration of the safety, economics, and environmental implications of nuclear power would be explicitly called for.

In addition, the Minnesota legislature periodically produces reports and positions that enable a more comprehensive look at the issues surrounding nuclear power. These efforts would continue to inform the debate.

Related Policies/Programs in Place

Existing IRP measures require consideration of relatively low-value GHG adders in the planning process, but do not require specific analysis of nuclear power as a GHG-reducing supply option. If a comprehensive GHG policy were implemented in the state's electric power sector, it would most likely overlap with this policy, although it is likely that full consideration of nuclear power options could still require a dedicated policy.

Type(s) of GHG Reductions

Avoided emissions from fossil fuel generation.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources:

- U.S. DOE, EIA, Office of Energy Statistics, *Assumptions to the Annual Energy Outlook 2007*, DOE/EIA-0554, April 2007. Available at: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf.
- Capital cost, transmission, fixed O&M, and variable O&M escalation factors developed by the MCCAG.

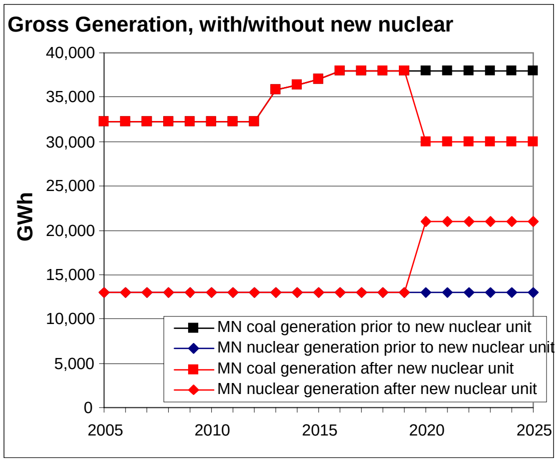
Quantification Methods:

This policy would provide support and incentives for life extension at existing nuclear power plants and for study of potential new nuclear power plants in Minnesota. Since it calls for the installation of a new unit in the post-2025 time frame, it is a nonquantified option. As a sensitivity to obtain a sense of the cost-effectiveness of the option, it has been modeled as a new nuclear power station in Minnesota using the following key assumptions:

- The installation year for the station is 2020.
- Upstream fuel-cycle GHG emissions associated with nuclear generation should be accounted for.
- The size of the station is 1,100 MW.
- New nuclear power would displace generation from existing, fully depreciated coal-fired generation within Minnesota.

Figure G-16 summarizes the impacts of this policy on gross generation. The upper curve represents the total Minnesota coal generation before and after the introduction of the new nuclear station, while the lower curve represents the total Minnesota nuclear generation before and after the introduction of the new nuclear station.

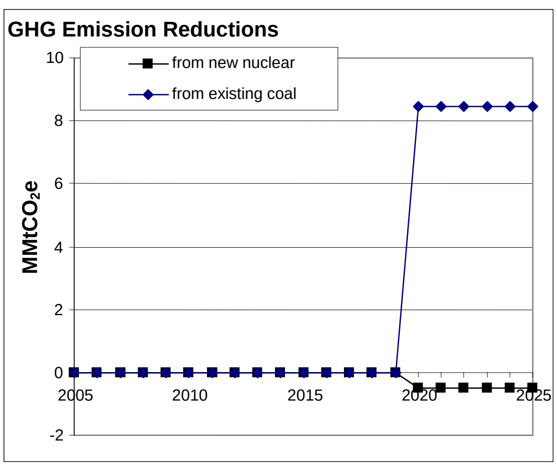
Figure G-16. Impacts on gross generation, with and without new nuclear power



GWh = gigawatt-hours.

Figure G-17 summarizes the GHG reductions resulting from implementing the policy. The upper curve represents the annual CO_2e reductions associated with backed-down generation from existing coal-fired power stations in Minnesota. The lower curve represents the annual CO_2e reductions associated with increased generation from the new nuclear power station in Minnesota. The net annual emission reductions in 2015 and 2025 are 0.0 and 8.0 $MMtCO_2e$, respectively. The cumulative net emission reductions over the 2005–2025 forecast period are 47.8 $MMtCO_2e$.

Figure G-17. Projected GHG emission reductions from new nuclear power



GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

The cost savings associated with avoided fuel and O&M at existing coal-fired facilities located in Minnesota is $39/MWh after deducting the capital cost component (2005$). The incremental costs associated with new nuclear power—capital costs, transmission costs, variable O&M costs, fixed O&M costs and fuel costs—total $164/MWh (2005$), which is then escalated to 2020 by 1.45 using the MCCAG escalation assumptions. The annual product of real levelized costs and displaced generation is an estimate of the annual cost savings. The NPV of these annual costs is $3.4 billion over the 2020–2025 period (2005$).

The cost-effectiveness of this policy was calculated as the quotient of the NPV and cumulative GHG emission reductions, or $70.2/tCO_2e$ reduced (2005$) (i.e., $3.4 billion divided by 47.8 MMt and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 1.

Key Uncertainties

Nuclear fuel availability; nuclear waste storage and disposal; security requirements; changes in federal policy (e.g., Nuclear Regulatory Commission relicensing, long-term waste repository); technology and economics of new units; industry-wide developments.

Additional Benefits and Costs

None.

Feasibility Issues

Mostly captured in the Key Uncertainties items above. Political feasibility also affects nuclear power, to differing degrees for life extensions and capacity upgrades, as opposed to new units.

Status of Group Approval

Complete.

Level of Group Support

Unanimous. With clarification that the state consider the costs and risks of installing a nuclear power station after 2025.

Barriers to Consensus

Not applicable.

ES-8. Advanced Fossil Fuel Technology Incentives, Support, or Requirements

Note: At its last meeting, the MCCAG decided that this option required further study and, therefore, that no benefits or costs would be ascribed to it. Hence, the results presented here—reflecting deliberations about the analysis by the ES Technical Work Group that took place over the course of the process—are for information purposes only.

Policy Description and Design

Goals: For coal to play a significant role in Minnesota's future energy system, its overall environmental profile must improve and come as close as possible to producing zero CO_2 emissions, while producing energy that is both affordable and reliable.

Timing: By 2020, the Upper Midwest region (Minnesota, Wisconsin, and North and South Dakota) should strive to have at least two IGCC projects with carbon capture and storage through design, construction, and into full operation. Similar goals for demonstrations of amine scrubbing, oxy-fuel combustion, and next-generation gasification technologies should be developed.

Parties Involved: Incumbent utilities, independent power producers, state regulators.

Implementation Mechanisms

- Have commercial-scale technology demonstrations using low-rank coals designed and under construction within the next 5 years, including demonstrations of IGCC with western sub-bituminous coal, IGCC with North Dakota lignite, and IGCC in conjunction with renewable energy, such as wind power and/or hydrogen production. Three demonstrations are already in progress: Excelsior Energy's Mesaba IGCC project proposed for northeastern Minnesota, Xcel Energy's proposed IGCC demo in Colorado, and Great River Energy's coal-to-liquids IGCC project with carbon capture and storage in North Dakota.
- Provide support for Front-End Engineering and Design (FEED) packages—state programs that offset some of the cost of FEED packages would allow utilities and developers to recoup their initial engineering costs through state tax credits or grants.
- Provide direct state financial incentives (e.g., tax credits and loan guarantees).
- Allow regulated utilities cost recovery for appropriate demonstration projects.
- Enhance IRP policies by using them to encourage low-CO_2 coal technologies—by incorporating proxy values for risk of future carbon regulations as Minnesota's 2007 legislation directs.
- Update workforce training and R&D programs and investments, with a focus on developing the gasification and carbon sequestration industries, including biomass to provide carbon neutral and carbon negative energy.
- Require development of the legal and regulatory frameworks needed for geologic storage of CO_2. New regulations should address issues of CO_2 ownership in storage and liability for

geologic storage of CO_2. State environmental agencies should develop permitting processes for underground storage, including guidance on pipelines, drilling, storage, measurement, monitoring, and verification.

- Support comprehensive assessments of geologic reservoirs at state and federal levels to determine storage potential and feasibility.
- Evaluate the feasibility of CO_2 transport via pipeline and "advanced sequestration" (i.e., mineralization, carbon nanofibers) if Minnesota determines it has no in-state storage opportunities.
- Provide tax incentives for carbon capture and storage, including when transported via pipeline for use in enhanced oil recovery operations.

Related Policies/Programs in Place

In 2003 the Minnesota legislature enacted two statutes—Minnesota Stat. 216B.1693 (the Clean Energy Technology Statute) and Minnesota Stat. 216B. 1694 (the Innovative Energy Project Statute)—providing important regulatory incentives, including an exemption from the requirements of a Certificate of Need and eminent domain rights for approved sites and routes for project facilities, to encourage the rapid development of IGCC projects in Minnesota.

Type(s) of GHG Reductions

Reductions in CO_2 emissions from coal combustion.

Estimated GHG Reductions and Net Costs or Cost Savings

- U.S. DOE, EIA, Office of Energy Statistics, *Assumptions to the Annual Energy Outlook 2007*, DOE/EIA-0554, April 2007. Available at: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf
- U.S. DOE, National Energy Technology Laboratory, "Volume 1: Bituminous Coal and Natural Gas to Electricity. Final Report," in *Cost and Performance Baseline for Fossil Energy Plants*, DOE/NETL-2007/1281, August 2007. Available at: http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf
- U.S. DOE, EIA, Office of Energy Statistics, "Electric Power Annual 2006—State Data Tables. 1990–2006 Net Generation by State by Type of Producer of Energy Source," EIA-906. Available at: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html
- Metz, B., O. Davidson, P. Bosch, R. Dave, and L. Meyer, eds., *Carbon Dioxide Capture and Storage: A Special Report of Working Group III of the Intergovernmental Panel on Climate Change*, New York, NY: Cambridge University Press, 2006. Available at: http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final/SRCCS_WholeReport.pdf
- Katzer, J., et al., *The Future of Coal: Options for a Carbon-Constrained World*, An Interdisciplinary MIT Study, Cambridge, MA: 2007. Available at: http://web.mit.edu/coal/The_Future_of_Coal.pdf

Quantification Methods:

This policy considers the role that coal could play in Minnesota's future energy system, provided its overall environmental profile improves and comes close to producing zero CO_2 emissions, while producing energy that is both affordable and reliable. It has been modeled thus far as a new IGCC unit with carbon capture and storage.

The MCCAG considered a primary analysis and three sensitivity analyses as follows:

- Primary analysis: new IGCC with carbon capture and storage
- Sensitivity analysis #1: new IGCC without carbon capture and storage
- Sensitivity analysis #2: retrofit of existing coal stations with carbon capture and storage
- Sensitivity analysis #3: new IGCC with 1% biomass co-firing and carbon capture and storage

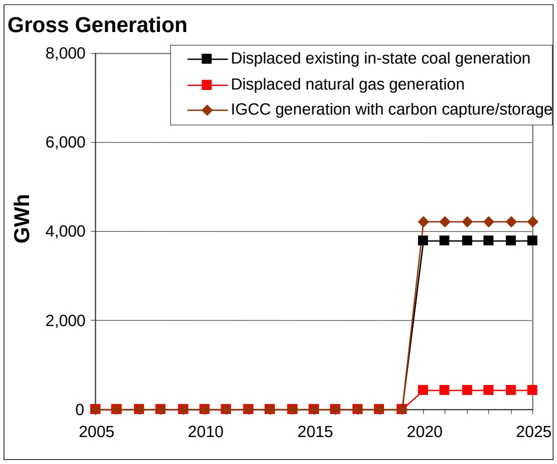
Primary Analysis: New IGCC With Carbon Capture and Storage

The key assumptions for the analysis of this policy are as follows:

- The start year is 2020.
- One 600-MW IGCC station is installed.
- The resources displaced by the new IGCC plant are assumed to be 10% natural gas-fired generation from combustion turbines in- and out-of-state, with the balance from existing in-state coal-fired generation.
- The capital costs associated with displaced resources are not depreciated.
- A heat rate penalty of 1,530 Btu/kWh above the assumed IGCC heat rate of 9,000 Btu/kWh is assumed to be the effect of adding carbon capture and storage technology.
- A carbon capture efficiency of 86% is assumed to be the effect of adding carbon capture and storage technology.
- A geologic storage site is located within 150 miles of the IGCC unit connected by a pipeline with a mass flow rate of 22.5 tCO_2/year.

Figure G-18 summarizes the impacts of this policy on gross generation for both new and displaced resources.

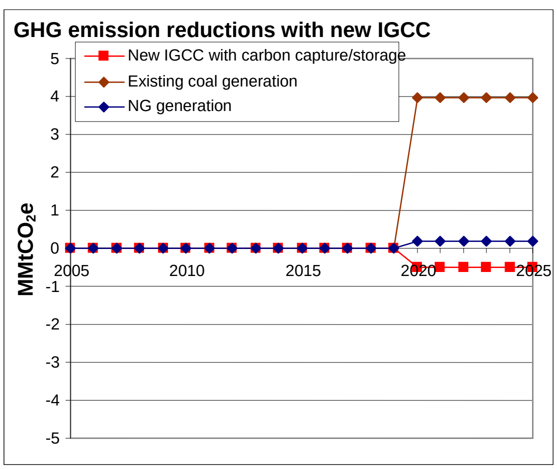
Figure G-18. Impacts of a new IGCC station with carbon capture and storage on gross generation



IGCC = integrated gasification combined-cycle; GWh = gigawatt-hours.

Figure G-19 presents projected CO_2e emission reductions resulting from this policy. The upper curve represents the annual CO_2e reductions associated with backed-down generation from existing coal-fired power stations in Minnesota. The curve in the middle represents the annual CO_2e reductions associated with backed-down generation from natural gas-fired power stations both in- and out-of-state. And the lower curve represents the annual CO_2e emission increases associated with the generation from the new IGCC with carbon capture and storage power station in Minnesota. The net annual emission reductions in 2025 are 3.66 $MMtCO_2e$, and the cumulative emission reductions over the 2020–2025 forecast period are 21.96 $MMtCO_2e$.

Figure G-19. GHG emission reductions from a new IGCC station with carbon capture and storage



GHG = greenhouse gas; IGCC = integrated gasification combined-cycle; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

There are cost savings associated with avoided capital, fuel, and O&M at existing coal-fired stations in Minnesota and natural gas-fired facilities (i.e., combustion turbines) located inside and outside Minnesota. The incremental costs associated with a new IGCC plant with carbon capture and storage include capital costs, transmission costs, variable O&M costs, fixed O&M costs, and fuel (i.e., coal only) costs. The annual product of real levelized costs and displaced generation is an estimate of the annual cost savings. The NPV of these annual costs is $3.506 billion over the 2020–2025 period (2005$).

The cost-effectiveness of this policy was calculated as the quotient of the NPV and cumulative GHG emission reductions, or $159.7/t$CO_2$e reduced (2005$) (i.e., $3.506 billion divided by 21.96 MMt and multiplied by a conversion factor of 1,000).

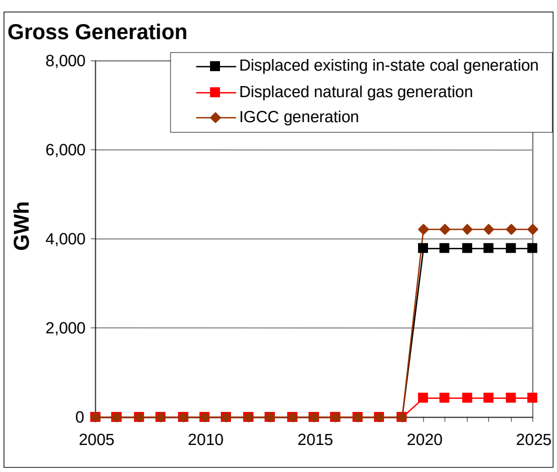
Sensitivity Analysis #1: New IGCC Without Carbon Capture and Storage

The key assumptions for this sensitivity analysis of this policy are as follows:

- The start year is 2020.
- One 600-MW IGCC station is installed.
- The resources displaced by the new IGCC plant are assumed to be 10% natural gas-fired generation from combustion turbines in- and out-of-state, with the balance from existing in-state coal-fired generation.
- The capital costs associated with displaced resources are not depreciated.

Figure G-20 summarizes the impacts of this policy on gross generation.

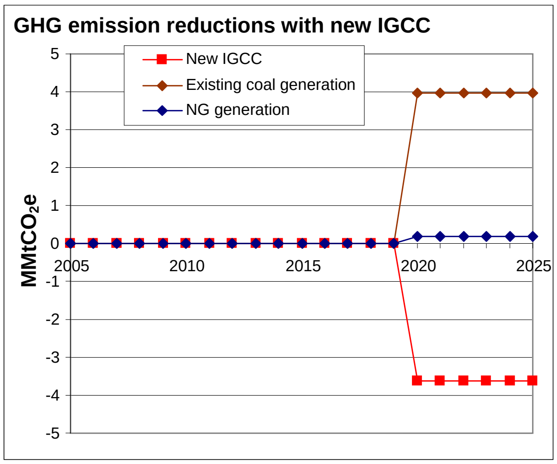
Figure G-20. Impacts of a new IGCC station without carbon capture and storage on gross generation



IGCC = integrated gasification combined-cycle; GWh = gigawatt-hours.

Figure G-21 summarizes the projected CO_2e emission reductions resulting from this policy's implementation. The upper curve represents the annual CO_2e reductions associated with backed-down generation from existing coal-fired power stations in Minnesota. The curve in the middle represents the annual CO_2e reductions associated with backed-down generation from natural gas-fired power stations both in- and out-of-state. And the lower curve represents the annual CO_2e emission increases associated with the generation from the new IGCC power station in Minnesota. The net annual emission reductions in 2015 and 2025 are 0.0 and 0.5 $MMtCO_2e$, respectively, and the cumulative emission reductions over the 2020–2025 forecast period are 3.2 $MMtCO_2e$.

Figure G-21. GHG emission reductions from a new IGCC station without carbon capture and storage



GHG = greenhouse gas; IGCC = integrated gasification combined-cycle; NG = natural gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

There are cost savings associated with avoided capital, fuel, and O&M at existing coal-fired stations in Minnesota and natural gas-fired facilities (i.e., combustion turbines) located inside Minnesota and outside Minnesota. The incremental costs associated with a new IGCC plant include capital costs, transmission costs, variable O&M costs, fixed O&M costs, and fuel costs. The annual product of real levelized costs and displaced generation is an estimate of the annual cost savings. The NPV of these annual costs is $1.95 billion over the 2020–2025 period (2005$).

The cost-effectiveness of this policy was calculated as the quotient of the NPV and cumulative GHG emission reductions, or $606.5/$tCO_2e$ reduced (2005$) (i.e., $1.95 billion divided by 3.2 MMt and multiplied by a conversion factor of 1,000).

Sensitivity Analysis #2: Retrofitting Existing Pulverized Coal Stations With Carbon Capture and Storage

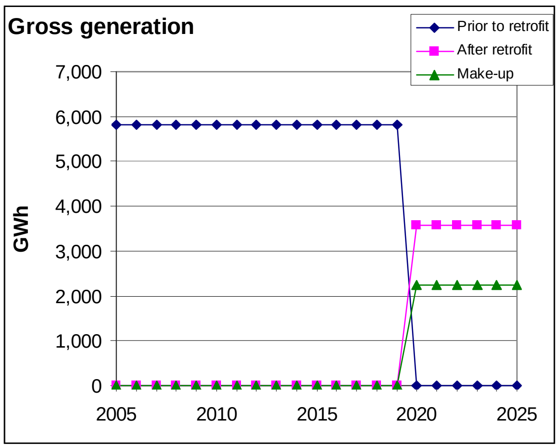
The key assumptions for this sensitivity analysis of this policy are as follows:

- The start year is 2020.
- One 500-MW IGCC station is installed using chemical absorption with monoethanolamine (MEA) for carbon capture.
- One 500-MW IGCC station is installed using oxygen firing for carbon capture.

- A plant de-rating of 41% is assumed for MEA and 36% for oxygen firing. Make-up power is available from in-state pulverized coal stations.
- Carbon capture efficiencies are 83% for MEA and 84% for oxygen-firing.
- A geologic storage site is located within 150 miles of the units connected by a pipeline with a mass flow rate of 22.5 tCO_2/year.

Figure G-22 summarizes the impacts of this policy on gross generation in Minnesota.

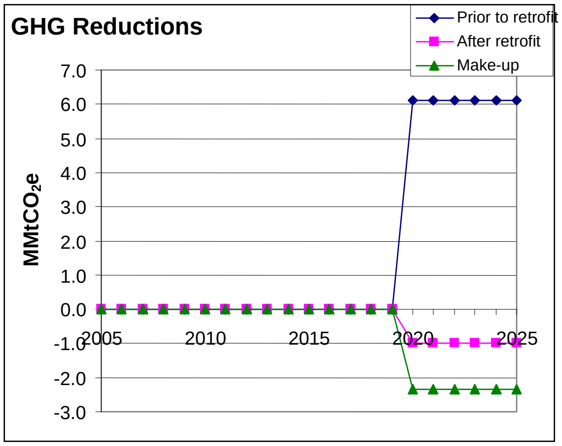
Figure G-22. Impacts on gross generation from retrofitting existing pulverized coal stations with carbon capture and storage



GWh = gigawatt-hours.

Figure G-23 summarizes the projected CO_2e emission reductions resulting from the implementation of this policy. The upper curve represents the annual CO_2e reductions associated with the existing coal-fired power stations in Minnesota prior to retrofitting. The curve in the middle represents the annual CO_2e emissions associated with the retrofitted coal stations. And the lower curve represents the annual CO_2e emissions associated with make-up power. The net annual emission reductions in 2015 and 2025 are 0.0 and 2.8 $MMtCO_2e$, respectively, and the cumulative emission reductions over the 2020–2025 forecast period are 16.7 MMt of CO_2e.

Figure G-23. GHG emission reductions from retrofitting existing pulverized coal stations with carbon capture and storage



GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

The incremental costs associated with retrofitting are incremental capital costs, variable O&M costs, fixed O&M costs, and fuel costs. The annual product of real levelized costs and displaced generation is an estimate of the annual costs. The NPV of these annual costs is $1.6 billion over the 2020–2025 period (2005$).

The cost-effectiveness of this policy was calculated as the quotient of the NPV and cumulative GHG emission reductions, or \$97.2/tCO_2e reduced (2005\$) (i.e., \$1.6 billion divided by 16.7 MMt and multiplied by a conversion factor of 1,000).

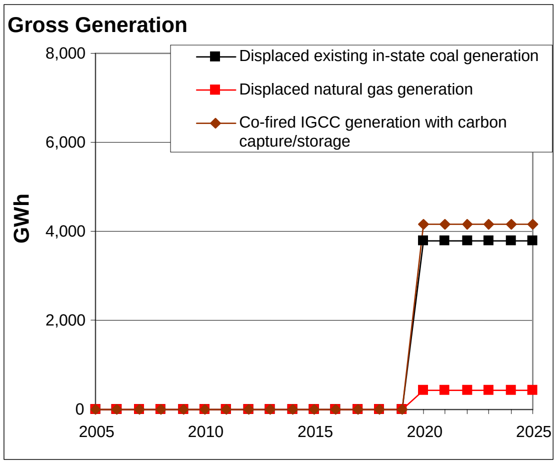
Sensitivity Analysis #3: New IGCC With 1% Biomass Co-Firing and Carbon Capture and Storage

The key assumptions for this sensitivity analysis of this policy are as follows:

- The start year is 2020.
- One 600-MW IGCC station is installed.
- The resources displaced by the new IGCC plant are assumed to be 10% natural gas-fired generation from combustion turbines in- and out-of-state, with the balance from existing in-state coal-fired generation.
- The capital costs associated with displaced resources are not depreciated.
- A heat rate penalty of 1,530 Btu/kWh above the assumed IGCC heat rate of 9,000 Btu/kWh is assumed to be the effect of adding carbon capture and storage technology.
- A carbon capture efficiency rate of 86% is assumed from adding carbon capture and storage technology.
- A geologic storage site is located within 150 miles of the IGCC unit connected by a pipeline with a mass flow rate of 22.5 $MtCO_2$/year.
- Coal is co-fired with biomass at 1% on an energy basis.

Figure G-24 summarizes the impacts of this policy on gross generation for both new and displaced resources. The total level of generation associated with the biomass portion of output from the IGCC unit is 42 gigawatt-hours from 2020 through 2025.

Figure G-24. Impacts on gross generation from a new IGCC station with 1% biomass co-firing and carbon capture and storage



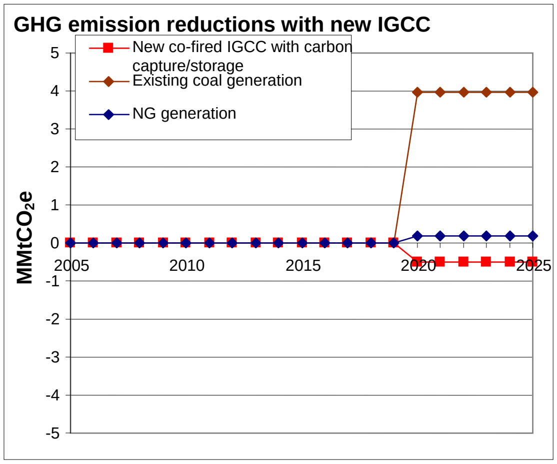
IGCC = integrated gasification combined-cycle; GWh = gigawatt-hours.

Figure G-25 summarizes the projected CO_2e emission reductions resulting from implementing this policy. The upper curve represents the annual CO_2e reductions associated with backed-down generation from existing coal-fired power stations in Minnesota. The curve in the middle represents the annual CO_2e reductions associated with backed-down generation from natural gas-fired power stations both in- and out-of-state. And the lower curve represents the annual CO_2e emission increases associated with the generation from the new IGCC with carbon capture and storage power station in Minnesota.

Annually, 0.04 MMt of biogenic CO_2e emissions from biomass are captured and stored at the geologic storage site. This level represents an incremental sequestration amount that would otherwise not be accounted for, because biomass is assumed to be used in a sustainable manner. Cumulatively, 0.26 MMt of biogenic CO_2e emissions are captured and stored at the geologic storage site.

The net annual emission reductions in 2025 are 3.71 $MMtCO_2e$. The cumulative emission reductions over the 2020–2025 forecast period are 22.25 $MMtCO_2e$.

Figure G-25. GHG emission reductions from a new IGCC station with 1% biomass co-firing and carbon capture and storage



GHG = greenhouse gas; IGCC = integrated gasification combined-cycle; NG = natural gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

There are cost savings associated with avoided capital, fuel, and O&M at existing coal-fired stations in Minnesota and natural gas-fired facilities (i.e., combustion turbines) located inside Minnesota and outside Minnesota. The incremental costs associated with new IGCC with carbon capture and storage include capital costs, transmission costs, variable O&M costs, fixed O&M costs, and fuel (i.e., coal and biomass) costs. The annual product of real levelized costs and displaced generation is an estimate of the annual cost savings. The NPV of these annual costs is $3.515 billion over the 2020–2025 period (2005$).

The cost-effectiveness of this policy was calculated as the quotient of the NPV and cumulative GHG emission reductions, or \$158.0/tCO_2e reduced (2005\$) (i.e., \$3.515 billion divided by 22.25 MMt and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 1.

Key Uncertainties

The mix of resources that is displaced by the new IGCC station.

Additional Benefits and Costs

Installation of more efficient technology.

Feasibility Issues

The technology is currently in the demonstration stage.

Status of Group Approval

Complete.

Level of Group Support

Unanimous. With clarification that Minnesota consider studying and/or facilitating carbon capture and storage demonstration projects in the post-2025 period, including carbon capture and storage paired with biomass.

Barriers to Consensus

Not applicable.

ES-10. Voluntary GHG targets

Policy Description

Numerous U.S. companies and organizations, including many utilities, have taken on voluntary GHG reduction commitments. Some of these are organized through the US EPA's Climate Leaders program. Others include participation in Power Partners and the EIA 1605(b) Voluntary GHG Emission Reduction Program. These commitments can be based on total GHG emissions in a given year or on specific voluntary projects, or they can be defined on an intensity basis (tCO_2e per MWh generated or delivered). Some entities with voluntary commitments also transact through the Chicago Climate Exchange (CCX), a self-regulating pilot program for reducing and trading GHG emissions in North America.

Policy Design

Goals: The goals for a Minnesota Voluntary GHG program include

1. Encouraging Minnesota business and citizens to voluntarily begin reducing GHG emissions immediately, without waiting for mandatory Minnesota or national GHG reduction program measures.

2. Provide a means for Minnesota voluntary GHG emission reductions to be quantified and recognized by applying Minnesota-approved GHG quantification methods.

3. Allow regulated entities assurance of cost recovery for voluntary GHG reduction measures that are previewed and approved by the MPUC as being in the best interest of Minnesota stakeholders, considering Minnesota climate change risks.

4. Provide documentation that supports voluntary measures receiving full credit under a future Minnesota or national mandatory or voluntary GHG reduction program (e.g., credit for early action).

5. Enable Minnesota voluntary GHG emission reduction measures to receive credit as certifiable CO_2 offsets for use within and outside of the United States.

Timing: Upon promulgation.

Parties Involved: All sectors and sources that wish to provide for voluntary GHG reductions or offsets, including government, industry, businesses, commercial building owners, and homeowners.

Other: Not applicable.

Implementation Mechanisms

Legislation will provide for voluntary GHG emission reductions to be registered and for cost recovery mechanisms. The MPCA shall be authorized to provide for voluntary measure recordkeeping. The MPUC shall be authorized to provide for review for public interest for cost recovery.

Related Policies/Programs in Place

None.

Type(s) of GHG Reductions

Reductions in emissions of carbon dioxide, as well as other GHGs, depending on participation in the program.

Estimated GHG Reductions and Net Costs or Cost Savings

By consensus, this option was not quantified.

Data Sources: Not applicable.

Quantification Methods: Not applicable.

Key Assumptions: Early action will be referenced against the Minnesota 2005 GHG emission inventory. Previous voluntary action performed by Minnesota entities under pre-2005 programs may also be quantified for receiving recognition. This will require third-party certification documents that the GHG emission reductions or offsets were delivered compared to 1990. (This procedure is established under the U.S. Climate Change Action Plan developed in accordance with the Rio Accords ratified by the U.S. Senate.)

Key Uncertainties

Not applicable.

Additional Benefits and Costs

None.

Feasibility Issues

Requires broad range of consensus and commitment for effective long-term effective administration.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

None.

ES-12. Distributed Renewable Energy Incentives and/or Barrier Removal

Policy Description

Distributed renewable energy should be encouraged, because it plays a part in the overall goal of reducing carbon emissions. This policy includes subsidies or incentives that encourage investment in small-scale distributed renewable energy resources.

Policy Design

Goals: The goal of this policy is to encourage investment in small-scale distributed renewable energy via incentives and/or the prevention of barriers. Incentives for distributed renewables should include (1) direct subsidies for purchasing or selling renewable technologies; (2) tax credits or exemptions for purchasing or selling renewable technologies; (3) feed-in tariffs, which provide direct payments to renewable generators for each kWh of electricity generated from a qualifying renewable facility (feed-in tariffs should take into consideration and recognize all the attributes of energy, including carbon impact to the purchaser and the “green impact”); (4) tax credits for each kWh generated from a qualifying renewable facility; (5) allowing the distributed generation projects to count toward the CIP savings goal of 1.5% annually if the investment is reasonable and prudent, whether utility-owned or customer-owned.

Timing: Analysis and review of technologies, financial incentives, and size of a project should begin immediately.

Parties Involved: All utilities serving customers in Minnesota, state agencies with jurisdiction, other interested stakeholders.

Other: A source to cover any financial incentive would need to be determined. The level of credit or funding should be consistent for all utilities (investor-owned utilities, municipal utilities, and cooperatives). The cost of the incentive should be shared among all end users, so that no one is overly burdened.

Implementation Mechanisms

- Funding mechanisms and incentives.
- Regulatory policies that support utility investments in small-scale distributed renewable energy.

Related Policies/Programs in Place

Minnesota RES of 25% by 2025. Existing matching programs for investment in photovoltaic systems. Wind production tax credits.

Type(s) of GHG Reductions

Reductions in CO_2 emissions from combustion sources.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources:

U.S. Census Bureau, "Annual Estimates of Housing Units for the United States and States: April 1, 2000 to July 1, 2005," HU-EST2005-0l, July 2007. (Annual data released at end of every July.) Available at: http://www.census.gov/popest/housing/HU-EST2005.html

U.S Census Bureau, "New Privately Owned Housing Units, Authorized Unadjusted Units for Regions, Divisions, and States," DC, July 2007. (Annual data released at end of every July.) Available at: http://www.census.gov/const/C40/Table2/t2yu200512.txt

U.S. Department of Energy, Energy Information Administration, "Residential Energy Consumption Survey 2001: Consumption and Expenditure Data Tables," November 18, 2004. Available at: http://www.eia.doe.gov/emeu/recs/recs2001/detailcetbls.html

Ratios of new residential/commercial floor space to total floor space, from U.S. Department of Energy, Energy Information Administration, "Table B1. Summary Table: Totals and Means of Floorspace, Number of Workers, and Hours of Operation." Available at: http://www.eia.doe.gov/emeu/cbecs/excel/b1.xls

U.S. Department of Commerce (DOC), National Oceanic and Atmospheric Administration (NOAA), National Environmental Satellite, Data, and Information Service, Historical Climatology Series 5-2: Monthly State, Regional and National Cooling Degree-Days Weighted by Population (Includes Aerially Weighted Temperature and Precipitation, Asheville, NC: National Climatic Data Center. Available at: http://lwf.ncdc.noaa.gov/oa/documentlibrary/hcs/cdd.200501-200607.pdf

U.S. DOC, NOAA, National Environmental Satellite, Data, and Information Service, Historical Climatology Series 5-1: Monthly State, Regional and National Heating Degree-Days Weighted by Population (Includes Aerially Weighted Temperature and Precipitation, Asheville, NC: National Climatic Data Center. Minnesota. Available at: http://lwf.ncdc.noaa.gov/oa/documentlibrary/hcs/hdd.200507-200607.pdf

Martha McMurry, *Minnesota Population Projections 2005–2035*, St. Paul, MN: Minnesota State Demographic Center, June 6, 2007 http://www.demography.state.mn.us/documents/MinnesotaPopulationProjections20052035.pdf

U.S. Department of Energy, Energy Information Administration, Office of Energy Statistics, "Form EIA-826 Database Monthly Electric Utility Sales and Revenue Data (2005)." Available at: http://www.eia.doe.gov/cneaf/electricity/page/eia826.html

U.S. Department of Energy, Energy Information Administration, Office of Energy Statistics, "1990–2006 Revenue from Retail Sales of Electricity by State by Sector by Provider," EIA-861. Available at: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html

Energy Efficiency Task Force Report to the Clean and Diversified Energy Advisory Committee of the Western Governors' Association, *The Potential for More Efficient Electricity Use in the*

Western United States, Denver, CO: Western Governors' Association, January 2006. Available at: http://www.westgov.org/wga/initiatives/cdeac/Energy%20Efficiency-full.pdf

Quantification Methods:

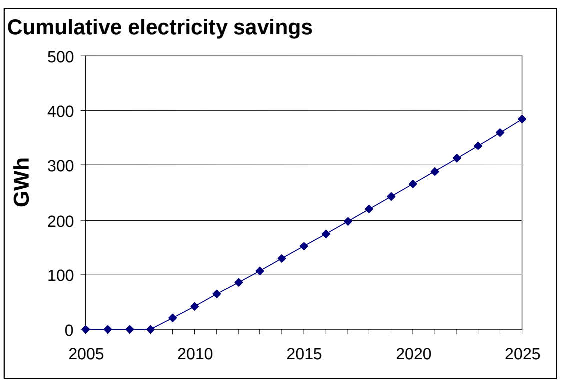
This policy encourages investment in small-scale distributed renewable energy via incentives and/or the prevention of barriers. It has been modeled as a penetration of solar photovoltaic technology in new residential housing and commercial establishments.

The key assumptions for the analysis of this policy are as follows:

- The start-up year is 2009.
- The penetration of residential distributed renewable systems in new homes and new commercial establishment is 5%.

Figure G-26 summarizes the cumulative savings associated with the penetration of distributed renewable energy in new residential and commercial units.

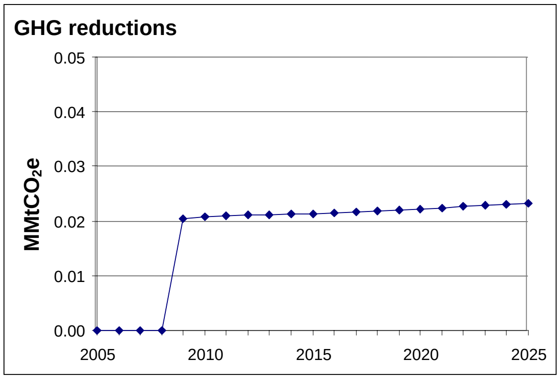
Figure G-26. Cumulative electricity savings from distributed renewable energy



GWh = gigawatt-hours.

Figure G-27 presents the annual CO_2e emission reductions resulting from distributed renewable energy. The annual emission reductions in 2015 and 2025 are 0.021 and 0.023 $MMtCO_2e$, respectively, while the cumulative emission reductions over the 2009–2025 forecast period are 0.37 $MMtCO_2e$.

Figure G-27. GHG emission reductions from distributed renewable energy



GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

There are cost savings associated with avoided fuel and O&M at existing power stations in Minnesota, along with incremental costs associated with new solar photovoltaic technology. The annual product of real levelized costs and displaced generation is an estimate of the annual cost savings. The NPV of these annual costs is $0.029 billion over the 2009–2025 period (2005$).

The cost-effectiveness of this policy was calculated as the quotient of the NPV and cumulative GHG emission reductions, or $78.1/$tCO_2e$ (2005$) (i.e., $0.029 billion divided by 0.37 MMt and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 1.

Key Uncertainties

None.

Additional Benefits and Costs

Reduction in electric transmission and distribution system; reduced air pollution.

Feasibility Issues

Structuring of the incentive.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

ES-13. Technology-Based Approaches, Including Research & Development, Fuel Cells, Energy Storage, Distributed Renewable Energy Technologies, etc.

Policy Description

Technology and innovation play a critical role in the development of economic processes, including energy production and use. Major progress in climate change policy requires improvements to technologies as well as increased rates of technology adoption and use. Trends toward smaller scale in energy production technology, combined with the impact of automation and remote system controls, present challenges to current business models and operational procedures.

This policy is an umbrella covering several technology-related policy options that together can contribute to GHG emission reductions in Minnesota.

Policy Design

Goals: This set of policies would provide state government and other private and public parties with resources and incentives for analysis, targeted R&D, market development, and adoption of GHG-reducing technologies that are not covered by other policies. The overall goals would be

- To position Minnesota as a world leader in climate-related technology development and deployment,
- To achieve actual emission reductions from technology investments, and
- To develop state industries with high in-state and export capability.

Timing: This policy is intended to come into effect in 2008 and 2009 and would continue indefinitely as an enabling mechanism for other climate-related policies.

Parties Involved: Minnesota government. Private and public partners on a voluntary basis.

Implementation Mechanisms

An R&D budget line item would be created to fund a small staff in the Commerce Department or another related agency. This group would follow technology trends and identify critical technology pathways as well as opportunities for collaboration and funding from other sources.

In addition, a Clean Technologies Innovation Program would be funded at the state level to provide grants and incentives as they are identified by the state along with other sources of public input into the prioritization process. Two models would be the California Public Interest Energy Research (PIER) program and the New York State Energy Research and Development Agency (NYSERDA). Utilities would be able to apply as partners for these funds.

Finally, the state's regulated utilities would be allowed to devote a percentage of their sales revenue to substantial R&D projects on a voluntary basis as part of their overall energy supply portfolios. The invested capital portion of these projects would be given advantageous cost recovery as an incentive to carry out such projects. This policy could be relaxed when effective climate change policy comes into effect, although there may still be merit in continuing some level of incentive for utility R&D effort even when climate policy is in place.

These policies would replace the current, more limited Renewable Development Fund.

Related Policies/Programs in Place

State efforts on innovation, including biotechnology, agriculture, and transportation.

Renewable Development Fund.

Tax credits and federal incentives.

Technology-specific policies such as hybrid vehicle or solar pilot programs and incentives.

Type(s) of GHG Reductions

Various, from no direct reductions to direct offset of emitting fuels and processes to actual uptake and use of GHGs, thus removing them from the atmosphere.

Estimated GHG Reductions and Net Costs or Cost Savings

By consensus, this option was not quantified.

Data Sources: Not applicable.

Quantification Methods: Not applicable.

Key Assumptions: Not applicable.

Key Uncertainties

Funding level stability

Ability to identify productive technology pathways

Measures of success and program oversight

Additional Benefits and Costs

None.

Feasibility Issues

Requires broad range of skills for effective administration.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

None.

ES Reductions from Recent Actions

Summary List of Recent Actions

	Policy Option	GHG Reductions ($MMtCO_2e$)			Net Present Value 2008–2025 (Million $)	Cost-Effective-ness ($\$/tCO_2e$)	Level of Support
		2015	2025	Total (2008–2025)			
	Renewable Energy Production Incentives	4.2	9.8	91.8	$1,941	$21.1	
	Biomass for Electricity	0.6	0.6	11.4	$285	$25.0	
	Metro Emissions Reduction Plan (MERP)	3.2	3.1	57.4	$1,662	$29.0	

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $\$/tCO_2e$ = cost per ton of carbon dioxide equivalent.

Renewable Energy Production Incentives

Policy Description

This option focuses on financial incentives that promote the installation of renewable energy production capacity. It is focused primarily on residents, businesses, and other end-users rather than on research and development, outreach, or intergovernmental programs. The effect of these incentives is to encourage investment in renewable energy by providing direct financial support. Incentives are incorporated into policy, resulting in an assumed conversion rate of 1% per year from existing utilities to renewable energy sources. The conversion rate translates directly into the energy production and costs in Minnesota.

Existing/previous incentive programs in Minnesota consist of the following (http://www.state.mn.us/portal/mn/jsp/content.do?contentid=536885915&contenttype=EDITORIAL&agency=Commerce):

Wind Power—Program offered between 1 and 1.5 cents/kWh (kilowatt-hour) for 10 years for qualified wind energy projects of less than 2 MW. Approximately 225 MW are or will be subscribed in the program, which was closed to new applicants as of January 1, 2005.

Biogas—Payment of 1.5 cents/kWh for 10 years for generation from an on-farm anaerobic manure digester system (Statute 216C.41).

Hydropower—Payment of 1.5 cents/kWh for 10 years for generation after July 1, 1994, if dam is in existence by March 31, 1994, or substantially refurbished after July 1, 2001 (Statute 216C.41).

Policy Design

Goals: Subsidy to renewable energy generators of at least 1.0 cents for each kWh of electricity generated from a qualifying renewable facility. This would require a program similar to biogas incentives for biomass energy production and reauthorization of the previous wind power program.

Timing: Maintain current programs for biogas and hydropower and initiate new programs for biomass and wind. As a default, implement payments starting in 2008 and continue them through 2025.

Coverage of Parties: All power producers operating qualifying renewable facilities in Minnesota would receive the direct payments.

Implementation Mechanisms

The proposed implementation mechanism for this option is the direct payment mechanism. This represents direct subsidies for purchasing/selling renewable technologies given to the buyer or seller. Other possible implementation mechanisms include (a) tax credits or exemptions for purchasing or selling renewable technologies given to the buyer or seller, (b) tax credits or exemptions for operating renewable energy facilities, (c) feed-in tariffs which provide direct payments to renewable generators for each kWh of electricity generated from a qualifying renewable facility, and (d) tax credits for each kWh generated from a qualifying renewable facility.

Related Policies/Programs in Place

See policy description.

Type(s) of GHG Reductions

Renewable generation can reduce fossil fuel use in power generation and correspondingly reducing CO_2e emissions. To the extent that generation from coal, natural gas, and oil is displaced by renewable power sources, CO_2e emissions will decrease.

Estimated GHG Reductions and Net Costs or Cost Savings

The table below summarizes the annual GHG reductions in 2015 and 2025, the cumulative GHG reductions through 2025, the incremental cost of the option (NPV), and the cost-effectiveness of the option (NPV$/t$CO_2e$ avoided).

	Policy Name	GHG Reductions ($MMtCO_2e$)			NPV of Costs (Million $) 2005	Cost of Saved Carbon (2005$/t$CO_2e$ avoided)
		2015	2025	Total 2008–2025		
	Incentives for renewable energy production	4.2	9.8	91.8	$1,941	$21.1

NPV = net present value; $/t$CO_2e$ = cost per metric ton carbon dioxide equivalent

Data Sources: EIA's Annual Energy Outlook (AEO) for 2006; "Clean Energy Technologies: A Preliminary Inventory of the Potential for Electricity Generation" by O. Bailey and E. Worrell, LBNL-57451, April 2005.

Quantification Methods: Ideally, one would undertake a full economic modeling exercise to assess the least cost mix/level of renewable energy, relative to Minnesota resource constraints and the incentives proposed. However, such an exercise would be both time-consuming and subject to very large uncertainties. Given time and budget limitations, an alternative analysis strategy was used that aimed to use previous analysis within a transparent spreadsheet structure. Hence, the completed analysis used a simple spreadsheet tool to assess the impact that financial incentives for centralized renewables would have on the penetration of renewable energy. The analysis involves the following steps:

- Identify the type of renewable generation that would most likely be developed as a result of the production incentives;
- Estimate the incremental costs associated with each type of renewable technology on a societal costs basis;
- Estimate the incremental renewable generation resulting from the incentives;

- Estimate the amount of CO_2e emissions that are expected to be avoided by the additional renewables resulting from the renewable energy incentives relative to the Reference Case.

Key Assumptions: Where applicable, the key assumptions are the same as those used in analyzing the renewable portfolio standards (RPS). It is assumed that the transition rate from existing sources of energy to renewable power is 1% per year, starting in 2008. The mix of renewable power is assumed to include wind, biomass and biogas. It is assumed that coal is the displaced energy source for all new renewable power. Due to current and anticipated environmental regulations, hydropower is discounted as contributing to the mix of renewable power.

Analytical issues: There were several assumptions that were made in quantifying the GHG reduction benefits and cost-effectiveness of this option, as follows:

- *Amount of incentive*—The maximum level of the incentive was set at $0.015/kWh (i.e., 1.5 cents/kWh). It was assumed that the incentives would remain in place until 2025.
- *Renewable energy mix*—The renewable energy mix for wind, biomass and biogas is assumed to be the same as their current relative prevalence. As a result, renewable energy additions would be comprised of 90% wind, 8% biomass and 2% biogas. The energy mix is assumed to roll out at a rate of 1% of total generation per year, starting in 2008. This is likely an upper-bound estimate of the conversion rate. Table F-1 shows the amount of energy generated in 2015 and 2025 for all sources, the displaced source (coal) and for each of the renewable sources (wind, biomass, and biogas).

Table F-1. Maximum estimate of generation from different sources for Minnesota

Resource	2015 (GWh)	2025 (GWh)
All sources	55,167	57,945
Coal	26,674	18,577
Wind	7,182	14,598
Biomass	2,534	5,880
Biogas	142	255

GWh = gigawatt hours

- *Conversion rate*—The conversion rate specified above (1% per year) is likely a high-end estimate of conversion. It has not been compared to production constraints that may exist for each of the renewable sources analyzed. The use of a conversion rate of 0.1% may represent a best estimate and would likely not be constrained by renewable energy supplies. Table F-2 presents the results assuming a lower transition rate (0.1% per year) from coal to other renewable resources.

Table F-2. Best estimate of generation from different sources for Minnesota

Resource	2015 (GWh)	2025 (GWh)
All sources	55,167	57,945
Coal	30,522	27,577
Wind	3,719	6,543
Biomass	2,226	5,164
Biogas	65	76

GWh = gigawatt hours

- *Marginal impact of renewable generation:* The introduction of new renewable power associated with this alternative is assumed to displace generation from existing and/or new facilities. This analysis assumes that 100% of the generation displaced by the new renewable power sources would be coal-fired.

Ancillary benefits: There are a number of benefits that are worth noting. First, reductions in overall energy consumption and the shift from fossil fuel generation as a result of the incentives would lead to reductions in criteria air pollutants and, consequently, health costs associated with those pollutants. Second, the renewable generation promoted by the incentives, though small in magnitude, could nevertheless provide a fuel price hedge effect against fossil fuel price volatility. Finally, the operating costs of renewable generation, primarily maintenance, are generally spent locally and can provide a direct boost to local economies.

Key Uncertainties

The primary uncertainty is the rate at which renewable incentives will replace coal-supplied energy with renewable energy sources. The estimate of 1% per year from 2008 to 2025 likely represents an upper-bound estimate of replacement.

The following items, which could affect the feasibility of and support for this option, have not been fully explored:

- Total NPV cost to MN of implementing the renewable energy incentives.
- Potential impact on utility rates of the renewable energy incentives.

Additional Benefits and Costs

Introducing additional renewable generation also reduces emissions of local and regional air pollutants, such as sulfur and nitrogen oxides which, in turn, reduce the human health and other impacts of those emissions.

Feasibility Issues

Unknown.

Status of Group Approval

Unknown.

Level of Group Support

Unknown.

Barriers to Consensus

Unknown.

Biomass for Electricity (2005–2007)

Policy Description

This policy option is designed to capture the effects of two biomass projects undertaken within the State of Minnesota in 2006 and 2007. The total capacity of these plants is 80 MW. A brief description of each is provided below.

Laurentian Energy—The Hibbing and Virginia Public Utilities have created an energy authority, Laurentian Energy, which produces 35 MW of power, fueled by renewable biomass. The biomass re-powers the coal-fired boilers in Hibbing and Virginia and was initiated in 2006.

Fibrominn—The Fibrominn Corporation installed a 55-MW poultry-litter-fired power plant in Benson, MN. The plant came on line in October of 2007 (http://www.fibrowattusa.com).

Policy Design

None.

Implementation Mechanisms

None.

Related Policies/Programs in Place

This policy is related to other renewable energy initiatives that incorporate the inclusion of biomass into the power mix for Minnesota, including the recent actions for Biomass for Electricity and Renewable Energy Production Incentives analyzed. It provides proof-of-concept for innovative design and execution of renewable energy projects.

Type(s) of GHG Reductions

Renewable generation can reduce fossil fuel use in power generation and correspondingly reducing CO_2e emissions. To the extent that generation from coal, natural gas, and oil is displaced by renewable energy, CO_2e emissions will decrease.

Estimated GHG Reductions and Net Costs or Cost Savings

The table below summarizes the annual GHG reductions in 2015 and 2025, the cumulative GHG reductions through 2025, the incremental cost of the option (NPV), and the cost-effectiveness of the option (NPV\$/tCO_2e avoided).

	Option Name	GHG Reductions ($MMtCO_2e$)			NPV of Costs $/MMtCO_2e$ (2005)	Cost of Saved Carbon (2005$/$tCO_2e$ avoided)
		2015	2025	Total (2008–2025)		
	Capture Existing Biomass Electricity Generation	0.6	0.6	11.4	$285	$25.0

NPV = net present value

Data Sources: EIA's Annual Energy Outlook (AEO) for 2006; "Clean Energy Technologies: A Preliminary Inventory of the Potential for Electricity Generation" by O. Bailey and E. Worrell, LBNL-57451, April 2005.

Quantification Methods: The nameplate power (MW) for each of the biomass plants was converted into an annual production rate, using the conversion factor of 1MW = 6.57 GWh. The costs and GHG reductions associated with displacing coal power with biomass power for these two plants was calculated and the NPV cost of the avoided GHG emissions were estimated.

Key Assumptions: It was assumed that coal was the displaced energy source for both of these biomass plants. The plants were assumed to have a useful life that would extend to at least 2025, and the plants would not be resource-constrained. It was assumed that the cost and emissions associated with the poultry-litter plant in Benson was the same as that for a standard biomass plant.

Key Uncertainties

The potential impact on utility rates of existing biomass has not been investigated.

Additional Benefits and Costs

Introducing additional renewable generation also reduces emissions of local and regional air pollutants, such as sulfur and nitrogen oxides which, in turn, reduce the human health and other impacts of those emissions.

Feasibility Issues

None.

Status of Group Approval

Unknown.

Level of Group Support

Unknown.

Barriers to Consensus

Unknown.

Metro Emissions Reduction Plan (MERP)

Policy Description

This policy option is designed to capture the effects of the Metro Emissions Reduction Plan (MERP) that was signed by Xcel Energy and the Minnesota Public Utilities Commission in 2003. Two retrofit projects were undertaken within the State of Minnesota and are expected to come on line in 2008 and 2009. The total capacity of these plants is 954 MW. A brief description of each is provided below.

High Bridge—The existing coal-fired plant will be replaced with a natural gas combined-cycle unit that includes two combustion turbines, heat recovery generators, and a new steam turbine. The plant will be installed in a new facility adjacent to the existing facility, which will be demolished when the new plant is completed (May 2008). The projected capacity for this plant is 515 MW (http://www.pca.state.mn.us/hot/xcel.html).

Riverside—Two existing coal-fired units will be replaced with natural gas combined-cycle units. This plant is expected to be in service in May of 2009 and will be rated at 439 MW (http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_11824_22655-877-0_0_0-0,00.html).

Policy Design

None.

Implementation Mechanisms

None.

Related Policies/Programs in Place

None.

Type(s) of GHG Reductions

All 6 statutory GHGs (CO_2, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride) will be reduced by the switch from coal to natural gas.

Estimated GHG Reductions and Net Costs or Cost Savings

The table below summarizes the annual GHG reductions in 2015 and 2025, the cumulative GHG reductions through 2025, the incremental cost of the option (NPV), and the cost-effectiveness of the option (NPV\$/tCO_2e avoided).

	Option Name	GHG Reductions ($MMtCO_2e$)			NPV of Costs (Million $) 2005	Cost of Saved Carbon (2005$/$tCO_2e$ avoided)
		2015	2025	Total (2007–2025)		
	Capture MERP conversion	3.2	3.1	57.4	$1,662	$29.0

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; NPV = net present value; $/tCO2e = dollars per metric ton of carbon dioxide equivalent.

Data Sources: EIA's Annual Energy Outlook (AEO) for 2006; "Clean Energy Technologies: A Preliminary Inventory of the Potential for Electricity Generation" by O. Bailey and E. Worrell, LBNL-57451, April 2005.

Quantification Methods: The nameplate power (MW) for each of the natural gas plants was converted into an annual production rate, using the conversion factor of 1 MW = 6.57 GWh. The costs and GHG reductions associated with displacing coal power with natural power for these two plants was calculated and the NPV cost of the avoided GHG emissions were estimated.

Key Assumptions: It was assumed that coal was the displaced energy source for both of these natural gas plants. The plants were assumed to have a useful life that would extend to at least 2025, and the plants would not be resource-constrained.

Effects on Rates: A key component of the MERP agreement was the ability of Xcel energy to recover capital costs (~$1 billion) with rate increases.

Key Uncertainties

The potential impact on utility rates of the MERP have not been investigated.

Additional Benefits and Costs

Introducing natural gas generation in lieu of coal generation also reduces emissions of local and regional air pollutants, such as sulfur and nitrogen oxides, which in turn reduce the human health and other impacts of those emissions.

Feasibility Issues

None.

Status of Group Approval

Unknown.

Level of Group Support

Unknown.

Barriers to Consensus

Unknown.

Annex 1: Key Assumptions

ES-1. Generation Performance Standard

Start year for GPS 2013

CO2e emission intensity threshold assumptions

	lbs CO2 per MWh	tonnes CO2e/MWh
MN power stations	1,100	0.50
contracts with out-of-state power stations	1,100	0.50
MN CHP stations	1,300	0.59
contracts with out-of-state CHP stations	1,300	0.59

Effect of the GPS on planned additions in MN that are already in the pipeline

1

1 GPS has **no** effect on MN planned capacity already in the pipeline (default)
2 GPS **affects** MN planned capacity already in the pipeline

Effect of the GPS on imports that are already in the pipeline

1

1 GPS has **no** effect on out-of-state imports already in the pipeline (default)
2 GPS **affects** out-of-state imports already in the pipeline

Replacement power from new utility/NUG capacity in MN to meet GPS (if needed)

1

1 75% natural gas CC; 25% wind (default)
2 user-defined

Replacement power from new CHP capacity in MN to meet GPS (if needed)

1

1 100% natural gas CC (default)
2 user-defined

Sensitivies for replacement power from imports from out-of-state utilities/NUGs to meet GPS (if needed)

2

1 100% natural gas CC
2 user-defined (default)

please fill in the table

Resource		Percent
Coal	insert value >>>	0%
Hydroelectric	insert value >>>	0%
Natural Gas CT	insert value >>>	0%
Natural Gas CC	insert value >>>	75%
Nuclear	insert value >>>	0%
Other	insert value >>>	0%
Other Gas	insert value >>>	0%
Geothermal	insert value >>>	0%
MSW	insert value >>>	0%
Landfill Gas	insert value >>>	0%
Biomass	insert value >>>	0%
Solar	insert value >>>	0%
Wind	insert value >>>	25%
Petroleum	insert value >>>	0%
Pumped Storage	insert value >>>	0%
Total		*100%*

Levelized cost raw inputs (2005$/MWh)

	Capacity	Transmission	Fixed O&M	Variable O&M	Fuel	Total
Pulverized coal	68.8	2.3	5.9	8.5	23.1	108.7
IGCC	84.2	2.5	8.8	11.4	22.6	129.5

Natural gas fuel price projection midpoint between the SAIC and high LBL projection

ES-3. Efficiency Improvements, Repowering, and Other Upgrades to Existing Plants

- Primary Analysis: biomass co-firing at Minnesota coal stations:

Start year for option 2013

Biomass co-firing assumption

2

1 Biomass represents 8% of fuel combusted annually at pulverized coal power stations (default)
2 User-defined (Biomass represents 1% of fuel combusted at pulverized coal power stations)

Ramp-up period for full utilization of biomass (years)

1

1 Policy ramps up linearly over a 5 year period (default)
2 User-defined (Policy ramps up linearly over a 10 year period)

Phase-in for co-firing portion

Start year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
2008				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2009					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011							0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012								0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2013									0.20%	0.40%	0.60%	0.80%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
2014										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2015											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2016												0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2017													0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2018														0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2019															0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2020																0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2021																	0.00%	0.00%	0.00%	0.00%	0.00%
2022																		0.00%	0.00%	0.00%	0.00%
2023																			0.00%	0.00%	0.00%
2024																				0.00%	0.00%
2025																					0.00%
	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.20%	0.40%	0.60%	0.80%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%

Estimated MN levelized costs (2005$/MWh) - All Scenarios

Capacity type	Capacity	ansmissi	ixed O&	riable O	Fuel	Total
Pulverized coal	68.8	2.3	5.9	8.5	23.1	108.7
Biomass co-firing	0.0	0.0	0.0	0.0	40.0	40.0

- Sensitivity Analysis: Natural gas repowering of an existing 600-MW coal station in Minnesota

Number of NGCC repowered coal stations units 1

Online year for NGCC repowered coal stations unit(s) 2013

Characteristics of power stations

	Units	NGCC	Coal
Size	MW	600	600
Capacity factor	%	65%	65%
Heat rate	btu/kWh	6,990	10,949
Annual gross generation	GWh/yr	3,416	3,416
CO2e emission factor	tCO2e/mmbtu	0.0539	0.0959
CO2e emission factor	E6 tCO2e/GWh	0.0004	0.0011

Levelized cost assumptions (2005$/MWh)

	Capacity	Transmission	Fixed O&M	Variable O&M	Fuel	Total
Pulverized coal	0.0	2.3	5.9	8.5	23.1	39.9
NGCC	40.9	3.1	3.0	2.3	102.7	152.0

ES-4. Natural Gas Transmission and Distribution Upgrades

Start year for transmission option 2010

Transmission system reduction in emissions (%)

1

1 Loss reduction is equivalent to 25% relative to the magnitude of emissions in the Reference Case (default)
2 User-defined (Loss reduction is equivalent to 25% relative to the magnitude of emissions in the Reference Case (default)

Ramp-up period for full upgrade of the transmission system (years)

1

1 Policy ramps up linearly over a 10 year period (default)
2 User-defined (Policy ramps up linearly over a 10 year period)

Phase-in for trasnmission system upgrading

Start year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
2008				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2009					0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2010						2.5%	5.0%	7.5%	10.0%	12.5%	15.0%	17.5%	20.0%	22.5%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%
2011							0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2012								0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2013									0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2014										0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2015											0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2016												0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2017													0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2018														0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2019															0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2020																0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2021																	0.0%	0.0%	0.0%	0.0%	0.0%
2022																		0.0%	0.0%	0.0%	0.0%
2023																			0.0%	0.0%	0.0%
2024																				0.0%	0.0%
2025																					0.0%
	0.0%	0.0%	0.0%	0.0%	0.0%	2.5%	5.0%	7.5%	10.0%	12.5%	15.0%	17.5%	20.0%	22.5%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%

Start year for distribution system option 2010

Distribution system reduction in emissions (%)

1

1 Loss reduction is equivalent to 15% relative to the magnitude of emissions in the Reference Case (default)
2 User-defined (Loss reduction is equivalent to 15% relative to the magnitude of emissions in the Reference Case (default)

Ramp-up period for full upgrade of the distribution system (years)

1

1 Policy ramps up linearly over a 8 year period (default)
2 User-defined (Policy ramps up linearly over a 8 year period)

Phase-in for distribution system upgrading

Start year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
2008				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2009					0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2010						1.9%	3.8%	5.6%	7.5%	9.4%	11.3%	13.1%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
2011							0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2012								0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2013									0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2014										0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2015											0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2016												0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2017													0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2018														0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2019															0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2020																0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2021																	0.0%	0.0%	0.0%	0.0%	0.0%
2022																		0.0%	0.0%	0.0%	0.0%
2023																			0.0%	0.0%	0.0%
2024																				0.0%	0.0%
2025																					0.0%
	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	3.8%	5.6%	7.5%	9.4%	11.3%	13.1%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%

ES-4. Natural Gas Transmission and Distribution Upgrades (continued)

Conversion factors

GWP	21	metric tons CO2e/metric ton CH4
1 Mcf	19.14	kg CH4
1 Mcf	1.03	mmbtu

Real discount rate

5%

Upper limit of emission reductions relative annual emissions

80% assumption

Natural gas savings by each mitigation option considered

Directed Inspection and Maintenance at Compressor Stations	29,413	Mcf of NG saved per year per station	
Reducing methane emissions from compressor rod packing systems	865	Mcf of NG saved per year per compressor	
Replacing wet seals with dry seals in centrifugal compressors	45,120	Mcf of NG saved per year per centrifugal compressor	
Directed Inspection and maintenance at gate stations and surface facilities	115	Mcf of NG saved per year per station	
Convert engine starting to nitrogen	1,350	Mcf of NG saved per year per engine	
Retrofit pneumatic devices with low-bleed kits	219	Mcf of NG saved per year per device	10 devices per compressor station
Using pipeline pump-down techniques to lower gas line pressure before maintenance	26,548	Mcf of NG saved per year per pipeline length	20 miles between block valves

Real levelized costs to achieve NG reductions for each mitigation option considered for the transmission system (2005$/Mcf avoided)

Directed Inspection and Maintenance at Compressor Stations	1.529
Reducing methane emissions from compressor rod packing systems	0.151
Replacing wet seals with dry seals in centrifugal compressors	22.213
Directed Inspection and maintenance at gate stations and surface facilities	5.198
Convert engine starting to nitrogen	1.015
Retrofit pneumatic devices with low-bleed kits	3.318
Using pipeline pump-down techniques to lower gas line pressure before maintenance	11.550

Weighted average city gate natural gas price (2005$/Mcf)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
2005$/mmbtu	8.3	8.5	7.9	7.9	7.5	7.3	7.0	6.8	6.6	6.7	6.6	6.7	6.9	6.8	6.7	6.8	6.8	6.9	7.0	7.1	7.1
2005$/Mcf	8.5	8.8	8.2	8.1	7.7	7.5	7.2	7.0	6.8	6.9	6.8	6.9	7.1	7.0	6.9	7.0	7.0	7.1	7.3	7.3	7.3

ES-5. Renewable and/or Environmental Portfolio Standard

Start year for RPS 2011

Share of backed-down imported coal generation that is fully depreciated

1

1 The share of imported generation that is fully depreciated is (default): 25%
2 The share of imported generation that is fully depreciated is: 0%

Share of backed down imported NG generation that is fully depreciated

1

1 The share of imported generation that is fully depreciated is (default): 25%
2 The share of imported generation that is fully depreciated is: 0%

Natural gas capacity composition - All Scenarios

Combustion turbine	100%
Combined cycle	0%
total	100%

Levelized cost assumptions for existing fossil capacity and all renewable capacity (2005$/MWh)

	Capacity	Transmission	Fixed O&M	Variable O&M	Fuel	Total
Coal	17.2	2.3	5.9	8.5	23.1	57.1
Natural Gas	8.0	4.0	1.4	20.5	158.8	192.6
Geothermal	140.4	4.0	63.5	0.0	0.0	207.9
MSW	81.1	2.7	29.4	0.0	0.0	113.1
Landfill gas	81.1	2.7	29.4	0.0	0.0	113.1
Biomass	93.2	2.7	13.7	5.3	40.0	154.9
Solar	195.7	0.0	0.0	5.6	0.0	201.2
Wind	131.3	5.7	16.7	0.0	0.0	153.7

ES-6. Nuclear Power Support and Incentives

Online year for new nuclear power 2020

Upstream fuel stages considered? 1

1 Upstream fuel stages **are** considered for coal and nuclear generation (default)
2 Upstream fuel stages are **not** considered for coal and nuclear generation

Cost & performance characteristics of new nuclear power stations in the online year

	Units	Effect of escalation without	with	Ratio
Size	MW	1,100	1,100	1.0
Contingency factor	dimensionless	1.00	1.00	1.0
Capital	2005 $/kW	49	71	1.45
Transmission	2005 $/kW	1	1	1.0
Fixed O&M	2005 $/kW-yr	1	1	1.0
Variable O&M	2005 mills/kWh	0.47	0	1.0
Fuel	2005 $/mmbtu	2.0	2.0	1.0
Capacity factor	%	84%	84%	1.0
Heat rate	btu/kWh	10,400	10,400	1.0
Annual gross generation	GWh/yr	8,128	8,128	1.0

Resource displaced 100% coal

CO2 emissions of nuclear fuel cycle

0.06 tonnes CO2 per MWh electricity produced

Stages of nuclear fuel cycl	Considered in above value?
Mining & milling	Yes
Conversion & transformation	Yes
Enrichment	Yes
fuel fabrication	Yes
electricity generation	Yes
reprocessing	No
LLW disposal	No
HLW disposal	No

CO2e emission factors (tonnes of CO2e per mmbtu)

	Natural gas	petroleum	Coal	gasoline	diesel	heavy fuel oil	Biomass	electricity (end use)
emission factor	0.0539	0.0783	0.0959	0.0783	0.0783	0.0783	0.0000	NA

Fuel cycle inputs

MMbtu input per MMBtu of coal delivered to the power station

Stages of coal fuel cycle	Considered?	Natural gas	petroleum	Coal	gasoline	diesel	heavy fuel oil	Biomass	electricity (end use)
Extraction	Yes	0.0001	0.0051	0.0006	0.0002	0.0039	0.0005	0.0000	0.0017
Beneficiation and processing	Yes	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Transport to power station	Yes	0.0000	0.0000	0.0000	0.0000	0.0088	0.0000	0.0000	0.0000
Total	NA	0.0001	0.0051	0.0006	0.0002	0.0128	0.0005	0.0000	0.0017

Additional tonnes CO2e per MMBtu associated with upstream fuel cycle stages

Stages of coal fuel cycle	Considered?	Natural gas	petroleum	Coal	gasoline	diesel	heavy fuel oil	Biomass	electricity (end use)	Total
Extraction	Yes	0.0000	0.0004	0.0001	0.0000	0.0003	0.0000	0.0000	NA	0.0008
Beneficiation and processing	Yes	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	NA	0.0000
Transport to power station	Yes	0.0000	0.0000	0.0000	0.0000	0.0007	0.0000	0.0000	NA	0.0007
Total	NA	0.0000	0.0004	0.0001	0.0000	0.0010	0.0000	0.0000	NA	0.0015

Estimated MN levelized costs (2005$/MWh) - All Scenarios

Capacity type	Capacity	ransmissio	Fixed O&M	ariable O&	Fuel	Total
Pulverized coal	68.8	2.3	5.9	8.5	23.1	108.7
Nuclear	127.6	2.4	15.5	0.8	18.7	165.0

ES-8. Advanced Fossil Fuel Technology Incentives, Support, or Requirements

Assumptions for Primary analysis: new IGCC with carbon capture and storage

Number of new IGCC/CCR units 1

Online year for new IGCC/CCR unit(s) 2020

Carbon capture & storage? Yes

Coal CO2e emission factor (tCO2e/mmbtu) 0.0959

Sensitivies for CCR technology 1

1 Central value (default)
2 High value
3 Low value

Cost & performance characteristics of new IGCC power stations

	Units	Value	Source
Size	MW	600	Assumption
Capacity factor	%	80%	Assumption
Heat rate	btu/kWh	9,000	Assumption
Annual gross generation	GWh/yr	4,205	Assumption

Cost & performance characteristics of new carbon capture & storage technology

		Range		
		Low	High	Central
Capture from IGCC	2005$/tCO2 captured	15.0	75.0	45.0
Transportation	2005$/tCO2 transported	1.0	8.0	4.5
Geologic storage	2005$/tCO2 injeceted	0.5	8.0	4.3
Monitoring/verification	2005$/tCO2 injected	0.1	0.3	0.2
subtotal	2005$/tCO2	16.6	91.3	54.0
Heat rate penalty	btu/kWh	11,880	9,270	10,530
CO2 emission reduction	%	81%	91%	86%

Resource displaced 2

1 existing coal represents — 100% of the resource displaced by the new IGCC plant
2 existing NG on the MISO system represents — 10% of the resource displaced by the new IGCC plant
with the balance of — 90% being existing in-state coal displaced by the new IGCC plant

Financial status of displaced resource 1

1 not depreciated
2 fully depreciated (default)

Levelized cost assumptions (2005$/MWh)

	Capacity	Transmission	Fixed O&M	Variable O&M	Fuel	Total
Pulverized coal	68.8	2.3	5.9	8.5	23.1	108.7
IGCC	122.3	2.5	8.8	11.4	22.6	167.6
IGCC/CCS (low)	142.3	2.7	9.4	11.4	17.8	183.5
IGCC/CCS (mid)	154.6	2.7	9.4	11.4	15.8	193.8
IGCC/CCS (high)	164.5	2.7	9.4	11.4	13.9	201.8
Natural gas CT	32.0	4.0	1.4	20.5	158.8	216.6

Assumptions for Sensitivity Analysis #1: New IGCC Without Carbon Capture and Storage

Number of new IGCC units 1

Online year for new IGCC unit(s) 2020

Carbon capture & storage? No

Characteristics of new IGCC power stations

	Units	Value
Size	MW	600
Capacity factor	%	80%
Heat rate	btu/kWh	9,000
Annual gross generation	GWh/yr	4,205
coal CO2e emission factor	tCO2e/mmbtu	0.0959
new IGCC CO2e e-factor	E6	0.0009

Resource displaced

2

1 existing coal represents 100% of the resource displaced by the new IGCC plant
2 existing NG on the MISO system represents 10% of the resource displaced by the new IGCC plant
with the balance of 90% being existing in-state coal displaced by the new IGCC plant

Financial status of displaced resource

1

1 not depreciated (default)
2 fully depreciated

Levelized cost assumptions (2005$/MWh)

	Capacity	Transmission	Fixed O&M	Variable O&M	Fuel	Total
Pulverized coal	68.8	2.3	5.9	8.5	23.1	108.7
IGCC	122.3	2.5	8.8	11.4	22.6	167.6
Natural gas CT	32.0	4.0	1.4	20.5	158.8	216.6

Assumptions for Sensitivity Analysis #2: Retrofitting Existing Pulverized Coal Stations With Carbon Capture and Storage

Type of coal station(s) to be retrofitted	subcritical coal
Number of retrofitted coal station(s)	2
Online year for retrofitted coal stations unit(s)	2020
Carbon capture & storage for retroitted unit?	Yes

Assumed retrofitting costs for coal stations for carbon capture

Typical coal plant capacity (MW)	500	
	MEA	Oxy-firing
derating	41%	36%
Coal plant capacity factor (%)	66%	66%
Incremental Capital cost (2005$/kW)	1,604	1,044
Incremental Capital cost (2005$/kWh)	0.0335	0.0218
Incremental O&M cost (2005$/kWh)	0.0121	0.0161
Heat rate before retrofit (btu/kWh)	9,749	9,749
Heat rate after retrofit (btu/kWh)	16,644	15,164
efficiency penalty (btu/kWh)	6,895	5,416
Carbon capture (%)	83%	84%

Incremental cost components for carbon capture

						First Year Non-Fuel Values							
	Cost and performacne assumptions					Non-fuel				Fuel price			
	Capital	Trans	Fixed O&M	Var O&M	Cap factor	Capital	Trans	Fixed O&M	Var O&M	Fuel price	Heat rate	Fuel cost	Total
Capture type	2005 $/kW	2005 $/kW	2005 $/kW-yr	2005 mills/kWh	%	2005 $/kWh	2005 $/kWh	2006 $/kWh	2005 $/kWh	2005$/mmbtu	btu per kWh	2005$/kWh	2005 $/kWh
MEA	1,604	0.00	0.00	12.10	66%	0.0335	0.0000	0.0000	0.0121	1.40	6,895	0.0096	0.0456
Oxy-firing	1,044	0.00	0.00	16.10	66%	0.0218	0.0000	0.0000	0.0161	1.40	5,416	0.0076	0.0379

Incremental levelized costs (including escalation)

	Capacity ($/kWh)			Transmission ($/kWh)			Fixed O&M ($/kWh)			Variable O&M ($/kWh)			Fuel ($/kWh)			Total ($/kWh)		
		Levelized Cost			Levelized Cost			Levelized Cost			Levelized Cost			Levelized Cost			Levelized Cost	
Capture type	NPV	Nominal	Real	NPV	Nominal	Real	NPV	Nominal	Real	NPV	Nominal	Real	NPV	Nominal	Real	NPV	Nominal	Real
MEA	0.463	0.050	0.037	0.000	0.000	0.000	0.000	0.000	0.000	0.148	0.016	0.012	0.129	0.014	0.010	0.739	0.079	0.059
Oxy-firing	0.301	0.032	0.024	0.000	0.000	0.000	0.000	0.000	0.000	0.197	0.021	0.016	0.101	0.011	0.008	0.599	0.064	0.048

Assumed cost and performance characteristics for retrofitting coal stations for carbon capture

source: See Appendix 3.E of "The Future of Coal: Options for a Carbon-Constrained World, MIT, 2007

	Units	on-retrofitte	MEA	Oxy-firing
Size	MW	500		
derating required	%	0%	41%	36%
Capacity after derating	MW	500	295	321
Capacity factor	%	66%	66%	66%
efficiency penalty	btu/kWh	0	6,895	5,416
Heat rate	btu/kWh	10,949	17,844	16,364
Annual gross generation	GWh/yr	2,907	1,715	1,863
Annual primary energy use	billion btu	31,827	30,604	30,493
CO2e emission factor	tCO2e/mmbtu	0.0959	0.0959	0.0959
Carbon capture	%	0%	83%	84%
CO2e emission factor	E6	0.0011	0.0003	0.0003
CO2e emissions	E6 tCO2e/yr	3.0537	0.5052	0.4719
CO2e captured	E6 tCO2e/yr	0.0	2.4312	2.4538
Incremental levelized cost - capture	2005$/MWh	0.0	59.6	48.2
Incremental levelized cost - transport/st	2005$/tCO2	0.0	9.0	9.0

Assumed cost and performance characteristics of make-up power

	Units	MEA	Oxy-firing
Type of station	NA	subcritical coal	
Annual gross generation make-up	GWh/yr	1,192	1,044
Levelized capital cost	2005$/MWh	0.00	0.00
Levelized transmission cost	2005$/MWh	0.00	0.00
Levelized fixed O&M cost	2005$/MWh	5.92	5.92
Levelized variable O&M cost	2005$/MWh	8.53	8.53
Levelized fuel cost	2005$/MWh	23.10	23.10
Total levelized cost	2005$/MWh	37.55	37.55

Assumptions for Sensitivity Analysis #3: New IGCC Co-Fired With 1% Biomass, With Carbon Capture and Storage

Number of new IGCC/CCR units 1

Online year for new IGCC/CCR unit(s) 2020

Carbon capture & storage? Yes

Coal CO2e emission factor (tCO2e/mmbt 0.0959

Sensitivities for CCR technology 1

1 Central value (default)
2 High value
3 Low value

Cost & performance characteristics of new IGCC power stations

	Units	Value	Source
Size	MW	600	Assumption
Capacity factor	%	80%	Assumption
Heat rate	btu/kWh	9,000	Assumption
Annual gross generation	GWh/yr	4,205	Assumption

Cost & performance characteristics of new carbon capture & storage technology

		Range		
		Low	High	Central
Capture from IGCC	005$/tCO2 capture	15.0	75.0	45.0
Transportation	05$/tCO2 transport	1.0	8.0	4.5
Geologic storage	005$/tCO2 injecte	0.5	8.0	4.3
Monitoring/verification	2005$/tCO2 injecte	0.1	0.3	0.2
subtotal	2005$/tCO2	16.6	91.3	54.0
Heat rate (including penalty)	btu/kWh	11,880	9,270	10,530
CO2 emission reduction	%	81%	91%	86%

Resource displaced

2

1 existing coal represents 100% of the resource displaced by the new IGCC plant
2 existing NG on the MISO sys 10% of the resource displaced by the new IGCC plant
with the balance of 90% being existing in-state coal displaced by the new IGCC plant

Financial status of displaced resource

1

1 not depreciated
2 fully depreciated (default)

Levelized cost assumptions (2005$/MWh)

	Capacity	ansmissi	Fixed O&	ariable O&	Fuel	Total
Pulverized coal	22.9	2.3	5.9	8.5	23.1	62.8
IGCC	122.3	2.5	8.8	11.4	22.6	167.6
IGCC/CCS (low)	142.3	2.7	9.4	11.4	17.8	183.5
IGCC/CCS (mid)	154.6	2.7	9.4	11.4	15.8	193.8
IGCC/CCS (high)	164.5	2.7	9.4	11.4	13.9	201.8
Natural gas CT	10.7	4.0	1.4	20.5	158.8	195.3

Biomass co-firing assumption

2

1 Biomass represents 8% of fuel combusted annually at pulverized coal power stations (default)
2 User-defined (Biomass represents 1% of fuel combusted at pulverized coal power stations)

Ramp-up period for full utilization of biomass (years)

1

1 Policy ramps up linearly over a 1 year period (default)
2 User-defined (Policy ramps up linearly over a 10 year period)

Phase-in for co-firing portion

Start year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
2008				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2009					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011							0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012								0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2013									0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2014										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2015											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2016												0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2017													0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2018														0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2019															0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2020																1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
2021																	0.00%	0.00%	0.00%	0.00%	0.00%
2022																		0.00%	0.00%	0.00%	0.00%
2023																			0.00%	0.00%	0.00%
2024																				0.00%	0.00%
2025																					0.00%
	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%

Biogenic biomass emission factor

29.9 tC per TJ
0.12 tCO2/mmbtu

Levelized biomass fuel price (2005$/MWh)

40

ES-12. Distributed Renewable Generation

Assumed start year for option

2009

Distributed renewable resource

Solar photovoltaics

Assumption for penetration of residential distributed renewable systems in new homes

1

1	Pentration of PVs	5%	(default)
2	User-defined		

Assumption for penetration of commercial distributed renewable systems in new buildings

1

1	Pentration of PVs	5%	(default)
2	User-defined		

Marginal resource associated with electricity savings

1

1	coal & natural gas, prorata (default)
2	100% coal
3	system average

Real discount rate

1

1	Use	5%
2	User-defined	

Levelized costs for distributed renewables (2005$/MWh)

196	Capacity
0	Balance of system
0	Installation
6	Variable O&M
201	Total

Assuemd capital cost decrease over time?

2

1	Yes
2	No (default)

Avoided costs for electric supply (2005$/MWh)

51	Capacity
4	Transmission
4	Fixed O&M
17	Variable O&M
111	Fuel
186	Total

Source: U.S Census Bureau annual data, **released end of every July**: http://www.census.gov/popest/housing/HU-EST2005.html

Table 1: Annual Estimates of Housing Units for the United States and States: April 1, 2000 to July 1, 2005

Geographic Area	Housing unit estimates						April 1, 2000	
	July 1, 2005	July 1, 2004	July 1, 2003	July 1, 2002	July 1, 2001	July 1, 2000	Estimates base	Census
United States	124,521,886	122,676,668	120,969,394	119,381,715	117,868,605	116,295,167	115,904,474	115,902,572
Minnesota	2,252,022	2,214,306	2,175,148	2,137,510	2,105,061	2,073,900	2,065,952	2,065,946

Source: U.S Census Bureau annual data, **released end of every July**: http://www.census.gov/const/C40/Table2/t2yu200512.txt

Table 2u. New Privately Owned Housing Units, Authorized
Unadjusted Units for Regions, Divisions, and States

December	2005 Year-to-Date					
	Total	1 Unit	2 Units	3 and 4 Units	5 Units or More	Num of Structures With 5 Units or More
United States	2,147,617	1,681,184	39,402	44,558	382,473	22,024
West North Centra	118839	95,144	3,090	2,879	17,726	1,092
Iowa	16,733	12,712	322	495	3,204	187
Kansas	14,404	11,814	552	361	1,677	137
Minnesota	**35,877**	**29,276**	**312**	**500**	**5,789**	**313**
Missouri	31,278	24,732	1,586	1,026	3,934	266
Nebraska	10,922	9,547	162	99	1,114	83
North Dakota	3,835	2,186	58	118	1,473	62
South Dakota	5,790	4,877	98	280	535	44

Residential buildings, 2005

Total housing units	2,252,022
New housing units	37,716
Existing housing units	2,214,306
Ratio of new units to existing units	0.02
Total residential electricity sales (GWh)	21,743
Estimated electricity use in new residential units (GWh)	370
Appliances multiplier	0.58
Electricity use for appliances - new residenital buildings (GWh)	215
Distribution renewable penetration	5%
Energy savings from distributed renewables (GWh)	18.52

Commercial buildings, 2005

Ratio of new to existing units	0.02
Total electricity energy use (GWh)	21,985
Energy intensity correction factor by climate zone and vintage	0.23
Percentage of electricity for lighting	54%
Commercial electricity used for lighting for new buildings (GWh)	49
Distribution renewable penetration	5%
Energy savings from distributed renewables (GWh)	2.46