Energy Supply
Technical Work Group

Summary List of Pending Priority Policy Options for Analysis

	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)			
ES-1	Generation Performance Standard						
	GPS affects unplanned capacity additions only	**0.0**	**0.0**	**0.0**	**$0**	**0.0**	**Pending**
	Sensitivity analysis—GPS affects all capacity additions	The impact of the GPS depends to a large extent on assumptions regarding resources that would be displaced by the RES and CIP. Sensitivity analysis could be conducted should the CCAG conclude that the GPS affects planned capacity additions.					
ES-3	Efficiency Improvements, Re-powering and other Upgrades to Existing Plants						
	Biomass co-firing	**0.2**	**0.4**	**4.2**	**$48**	**$12**	**Approved**
	Natural gas re-powering	2.3	2.3	29.9	$3,599	$120	Approved
ES-4	Transmission System Upgrading, Including Reducing Transmission Line and Distribution System Loss						
	Electric transmission and distribution upgrades	Un–quantified					Approved
	Natural gas transmission and distribution upgrades	**0.2**	**0.4**	**3.9**	**–$92.2**	**–$26.1**	**Approved**
ES-5	Renewable and/or Environmental Portfolio Standard	7.7	15.7	133	$7,502	$56.4	Enacted**
ES-6	Nuclear Power Support and Incentives						
	Installation of a nuclear power station after 2025	**0**	**0**	**0**	**$0**	**$0**	Pending
	Installation of a nuclear power station in 2020	0	8.0	47.8	$3,355	$70	Pending
ES-8	Advanced Fossil Fuel Technology Incentives, Support or Requirements						
	New IGCC with carbon capture and storage	**0.00**	**3.66**	**21.96**	**$3,506**	**159.7**	Pending
	New IGCC without carbon capture and storage	0.0	0.5	3.2	$1,953	$606.5	Pending
	Retrofitting existing coal stations with carbon capture and storage	0.0	2.8	16.7	$1,623	$97.2	Pending
	New IGCC with 1% biomass co-firing and carbon capture and storage	0.00	3.71	22.25	$3,515	$158.0	Pending

	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)			
ES-12	Distributed Renewable Energy Incentives and/or Barrier Removal	0.021	0.023	0.37	29.1	78.1	Pending

*MMt = million metric tons t=metric ton CO2e=carbon dioxide equivalent UC=unanimous consent NA=not applicable.

**Legislation enacted as of 2007.

Notes:

1. ES TWG recommendations are in **bold** above.

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

ES-1. Generation Performance Standard

Policy Description

A generation performance standard (GPS) is a mandate that requires those 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 generation performance standard would prevent utilities from making a long-term financial commitment to base load generation plants with CO_2 emissions in excess of 1,100 pounds of CO_2 per megawatt-hour.

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 five or more years, which includes procurement of base load generation. The TWG would like CCS 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 five or more years) and one that excludes them.

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 1300 pounds of CO_2/MWh.

Timing: Two alternative onset dates for the GPS— a) an immediate onset data that would apply to all base load projects not already in operation, and b) a delayed onset date that would exclude base load facilities currently under consideration in proceedings before the Public Utilities Commission. 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 Public Utilities Commission, which would review all long-term financial commitments to base load generation made by Minnesota utilities to ensure compliance with the generation performance standard.

Related Policies/Programs in Place

None.

Type(s) of GHG Reductions

Reduces carbon dioxide 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: The following data sources were used in the analysis of this mitigation option:

- Energy Information Administration, "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
- National Energy Technology Laboratory, "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 Form EIA-906, available at: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html

Quantification Methods:

This option is a mandate requiring those 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 of CO2 per MWh for power stations; 1,300 lbs of CO2 per MWh for combined heat and power (CHP) stations). The TWG has made the following key assumptions for the analysis of this option, as follows:

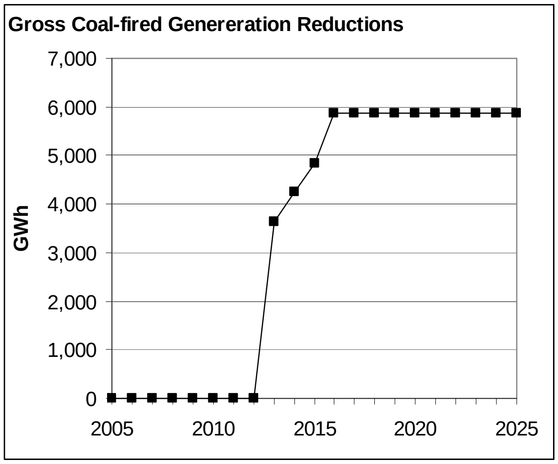
- The start year for the option is 2013.
- Two cases were analyzed:
  - *The GPS only affects new unplanned capacity*. This refers to part "b" under the Timing subsection of the Policy Design section above.
  - *The GPS affects all new capacity, planned and unplanned.* This refers to part "a" under the Timing subsection of the Policy Design section above.
- The need for replacement power to replace generation from capacity affected by the GPS should be subjected to an assessment of whether such power is needed, given projected MN electricity sales demand. If needed, replacement power comes from out-of-state with a mix of 75% natural gas-fired and the balance from wind.

Case 1: The GPS only affects new unplanned capacity

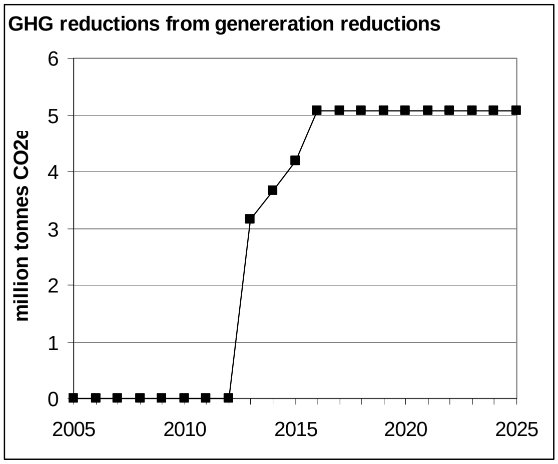
In this case, there are no GHG reduction benefits from the implementation of the GPS in MN as there are no unplanned capacity additions that exceed the emission intensity threshold.

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 MN. No replacement power needed due to the fact that electricity demand can be met by the combination of existing MN generation and forecasted levels of imports.

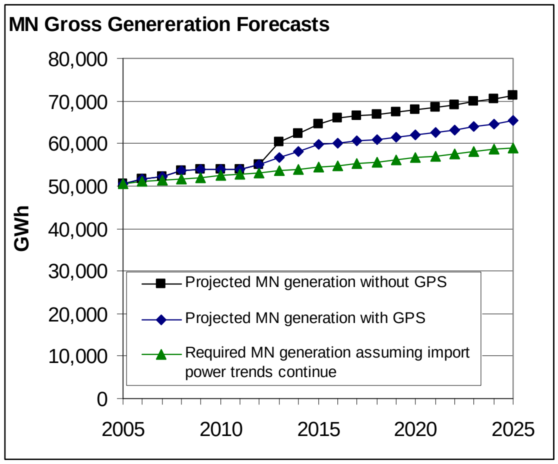
The impact of the option generation is summarized in the chart below. The curve represents the total annual reductions associated with the elimination of new planned coal-fired generation for MN.



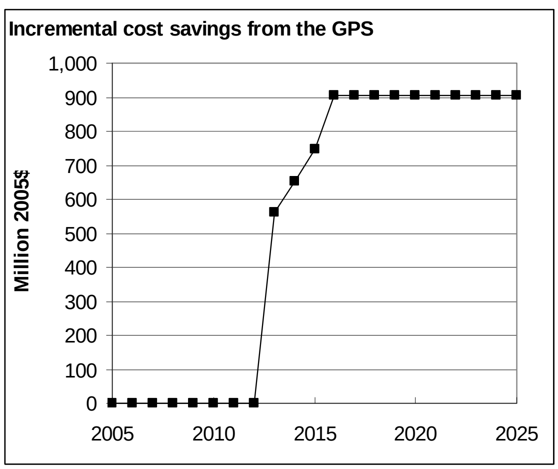
Regarding CO2-equivalent (CO2e) emission reductions, the impact of the option is summarized in the chart below. The curve represents the annual CO2e reductions associated with the elimination of new planned coal-fired generation. The annual emission reductions in 2015 and 2025 are 4.1 and 5.1 million tonnes CO2e, respectively. The cumulative emission reductions over the 2013-2025 period are 61.8 million tonnes CO2e.



Regarding the need for replacement power, the impact of the option is summarized in the chart below. The middle curve is the projected gross generation in MN after the implementation of the GPS. The lower curve is the "required" MN 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 MN after implementation of the GPS always exceed "required" MN gross generation, no replacement power is needed.



Regarding costs, there is capital, transmission, variable O&M, fixed O&M and fuel savings 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, 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 the chart below. The net present value of these annual costs are -$7.4 billion over the 2013-2025 period (2005$).



Regarding cost effectiveness, it was calculated as the quotient of the NPV and cumulative GHG emission reductions, -$120/tCO2e (2005$) (i.e., -7.4 billion divided by 61.8 million tonnes and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 2

Key Uncertainties

The GPS would expand PUC oversight to certain transactions or projects not currently subject to PUC 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 PUC approval. It is expected that the GPS approval process would be far more streamlined than the typical Certificate of Need review process.

Other uncertainties noted by the Technical Working Group include a) the need to consider whether a GPS is necessary if the state enacts a cap-and-trade program covering electric generation; b) whether the 1,300 pounds per megawatt hour threshold is set at the right level to encourage efficient CHP installations; c) whether natural gas peaker units could reasonably be included in the policy in addition to base load generation; and d) 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

The ES TWG recommends, by majority vote, that the application of the GPS exempt all planned capacity additions that are already at some stage of the regulatory process in MN.

Level of Group Support

The ES TWG support is unanimous in its support for the option, differing only in its appropriate coverage.

Barriers to Consensus

TBD – [blank until final vote by the MCCAG]

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

Policy Description

This policy would promote the identification and pursuit of cost-effective emissions reductions from existing generating units through improving their operating efficiency, adding biomass or other fuel changes, or adding carbon capture technology. This policy would complement a Generation Performance Standard (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. This policy would, in time, result in the identification of a portfolio of technological options for reducing GHG emissions and allow state utilities to share the opportunities they have identified.

CCS should 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 measure identified above.
- Create financial incentives that reward such emissions reductions.

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

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 the Public Utilities Commission.

Related Policies/Programs in Place

Existing IRP requirements (see above). The requirement is an important counterpart to a Generation Performance Standard (GPS), which only covers 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

- Energy Information Administration, "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)
- National Energy Technology Laboratory, "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 Form EIA-906, available at: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html

Quantification Methods:

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

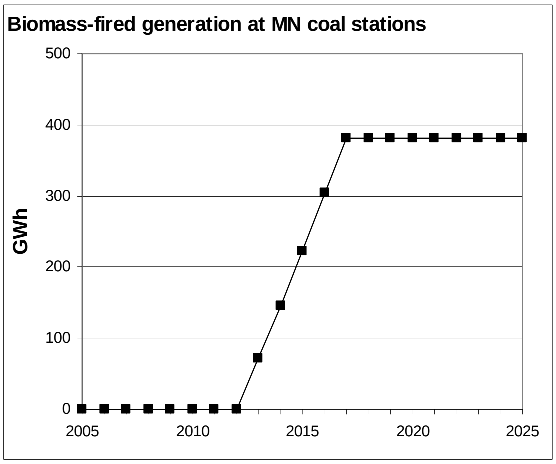
Primary Analysis: biomass co-firing at Minnesota coal stations:
The ES TWG has made the following key assumptions for the analysis of the biomass co-firing option, as follows:

- The start year for the option 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.
- Woodwastes and forest residues are the major form of biomass to be used, at a flat price of $2.5/mmbtu (2005$).
- The impact of the option on biomass supplies in Minnesota should be evaluated and supply/demand effects should be reflected in the price of biomass

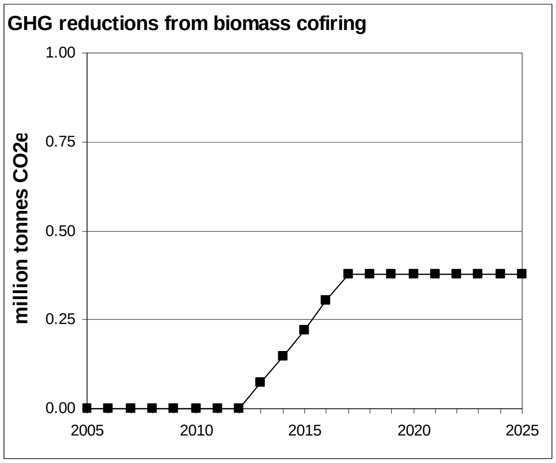
Sensitivity Analysis: Natural gas repowering of an existing 600 MW coal station in Minnesota
The ES TWG has made the following key assumptions for the analysis of the biomass co-firing option, as follows:

- The start year for the option is 2013.
- The coal station would be repowered with a natural gas combined cycle unit.

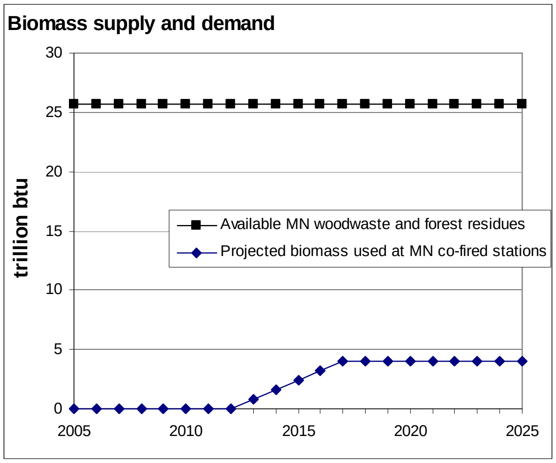
Regarding generation, the impact of the option is summarized in the chart below representing the total generation associated with co-fired biomass in Minnesota.



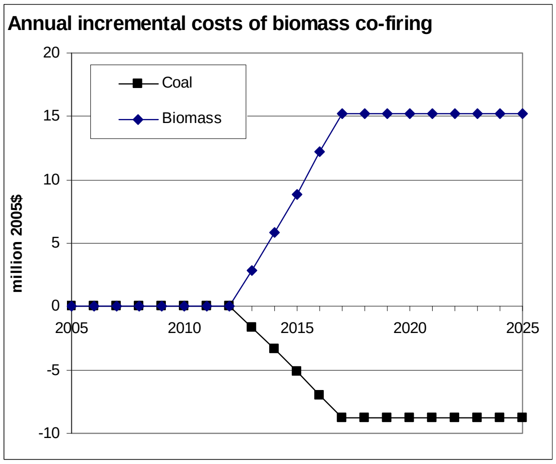
Regarding CO_2e emission reductions, the impact of the option is summarized in the chart below representing the annual CO_2e reductions associated with biomass co-firing. The annual emission reductions in 2015 and 2025 are 0.2 and 0.4 million tonnes CO_2e, respectively. The cumulative emission reductions over the 2005–2025 forecast period are 4.2 million tonnes CO_2e.



Regarding the demand/supply situation for woodwastes and forest residues, the impact of the option is summarized in the chart below. The projected biomass used at Minnesota coal stations would not exceed available Minnesota supply in any year.



Regarding the annual costs of the option, there are 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 the chart below. The net present value of these annual costs are $0.05 billion over the 2013–2025 period (2005$).

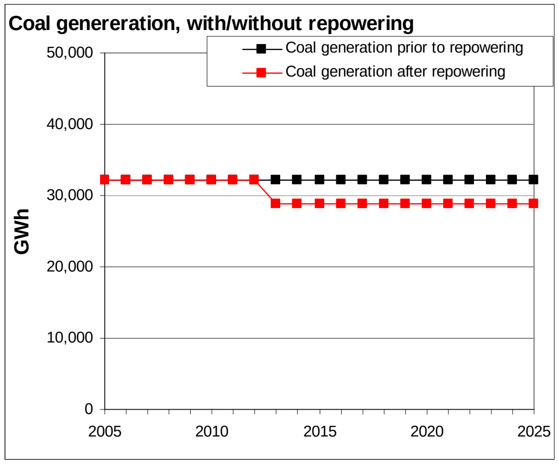


Regarding the cost-effectiveness of the option, it was calculated for Reference Scenario #1 as the quotient of the NPV and cumulative GHG emission reductions, $12/t CO_2e (2005$) (i.e., 0.05 billion divided by 4.2 million tonnes and multiplied by a conversion factor of 1,000).

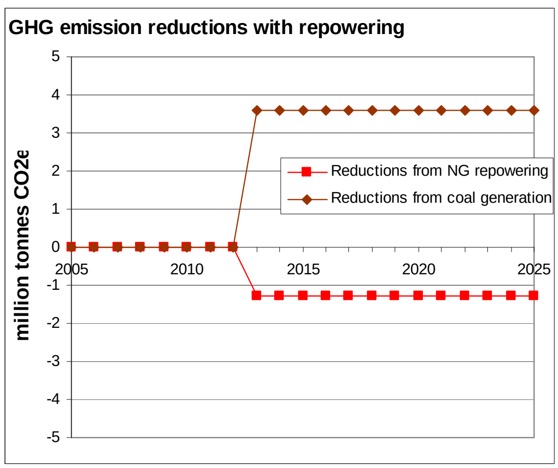
Sensitivity Analysis: Natural gas repowering of an existing 600 MW coal station in Minnesota
The ES TWG has made the following key assumptions for the analysis of the biomass co-firing option, as follows:

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

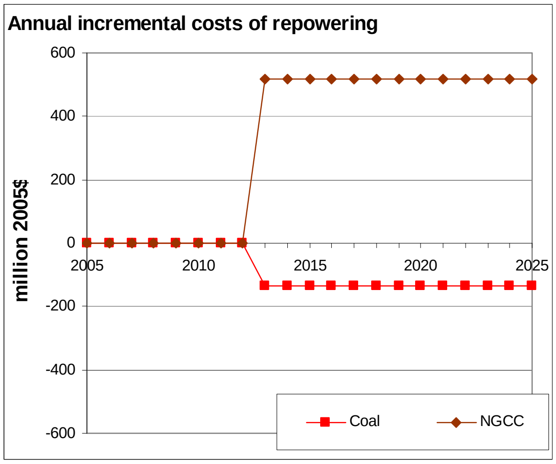
Regarding generation, the impact of the option is summarized in the chart below representing the total generation associated with existing coal stations, with and without the repowered facility in Minnesota.



Regarding CO_2e emission reductions, the impact of the option is summarized in the chart below representing 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 million tonnes CO_2e in 2015 and 2025. The net cumulative emission reductions over the 2013–2025 forecast period are 29.9 million tonnes CO_2e.



Regarding the annual costs of the option, 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 the chart below. The coal station was assumed to be fully depreciated. The net present value of these annual costs are $3.6 billion over the 2013–2025 period (2005$).



Regarding the cost-effectiveness of the option, it was calculated for Reference Scenario #1 as the quotient of the NPV and cumulative GHG emission reductions, $120/t CO_2e (2005$) (i.e., $3.6 billion divided by 29.9 million tonnes and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 2

Key Uncertainties

The Technical Working Group identified the following uncertainties: 1) whether and how the new source review provisions of the Clean Air Act would affect the promotion of plant upgrades; 2) how this option relates to the GPS proposal; 3) how the terms “cost-effective” should be defined; and 4) how it relates to the cap-and-trade proposals.

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

Pending—[until MCCAG moves to final agreement at meeting #8]

Level of Group Support

TBD—[blank until MCCAG meeting #8]

Barriers to Consensus

TBD—[blank until final vote by the MCCAG]

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 (R/W) acquisition. This increases environmental impacts through increased carbon emissions due to siting and clearing a R/W and the local impact on the environment, habitat, and on land use, enjoyment, and value of property.

Policy measures in support of this option 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 which 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.

There are several energy efficiency measures that can be implemented to reduce the 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, the state of Vermont offers 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 product.

Policy Design

Goals:

- Provide financial incentives for implementing smart energy (computer) technologies.
- Assess the effectiveness of the streamlining efforts enacted in 2005 to siting and routing of transmission lines to determine what additional streamlining activities 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 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 Operator, Gas Pipeline Companies

Implementation Mechanisms

As noted above

Related Policies/Programs in Place

Renewable energy objective, 25 by 2025.

Type(s) of GHG Reductions

Reduced carbon dioxide from fossil-fuel electricity generation; Avoided emissions from increased siting of renewable energy facilities; avoided methane emissions from leaks in natural gas distribution.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources:

- GHG Inventory and forecast for Minnesota prepared by Randy Strait ("GHGemitsum07_Working.xls" spreadsheet in a worksheet called "Stationary non CO_2 emissions")
- US GHG Inventory, available at: http://www.epa.gov/climatechange/emissions/downloads06/07CR.pdf
- Annex 3 of 2007 US GHG Inventory, available at: http://www.epa.gov/climatechange/emissions/downloads06/07Annex3.pdf
- EPA, "Directed Inspection and Maintenance at Compressor Stations," available at: http://www.epa.gov/gasstar/pdf/lessons/ll_dimcompstat.pdf
- EPA, "Reducing methane emissions from compressor rod packing systems," available at: http://epa.gov/gasstar/pdf/lessons/ll_rodpack.pdf
- EPA, "Replacing wet seals with dry seals in centrifugal compressors," available at http://www.epa.gov/gasstar/pdf/lessons/ll_wetseals.pdf
- EPA, "Directed Inspection and maintenance at gate stations and surface facilities," available at http://www.epa.gov/gasstar/pdf/lessons/ll_dimgatestat.pdf
- EPA, "Convert engine starting to nitrogen," available at: http://www.epa.gov/gasstar/pdf/pro_pdfs_eng/convertenginestartingtonitrogen.pdf

- EPA, "Retrofit pneumatic devices with low-bleed kits," available at: http://www.epa.gov/gasstar/workshops/midland-6806/gremillion2.pdf)
- EPA, "Using pipeline pump-down techniques to lower gas line pressure before maintenance," available at: http://www.epa.gov/gasstar/pdf/lessons/ll_pipeline.pdf

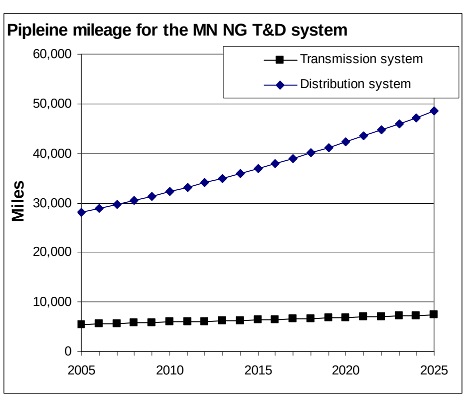
Quantification Methods:

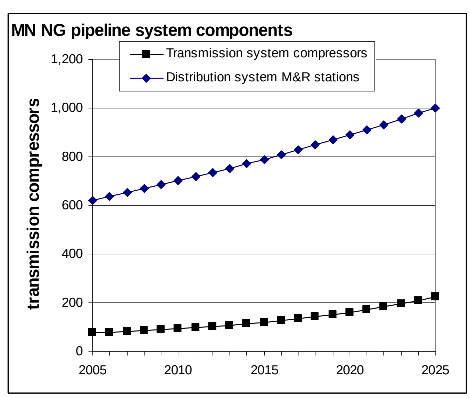
This option would improve electricity transmission systems to reduce bottlenecks, enhance throughput, and improve the efficiency of operations system wide. The option also targets reduction of leaks in natural gas pipelines to avoid methane emissions to the atmosphere and prevent the waste of valuable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

The option 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 option 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 transmission system is 8 years.

Regarding the characteristics of the Minnesota natural gas transmission system, the chart below summarizes the total projected mileage for both the transmission and distribution system (left), and the total projected number of compressors for the transmission system and the total number of metering and regulating (M&R) stations for the distribution system (right).





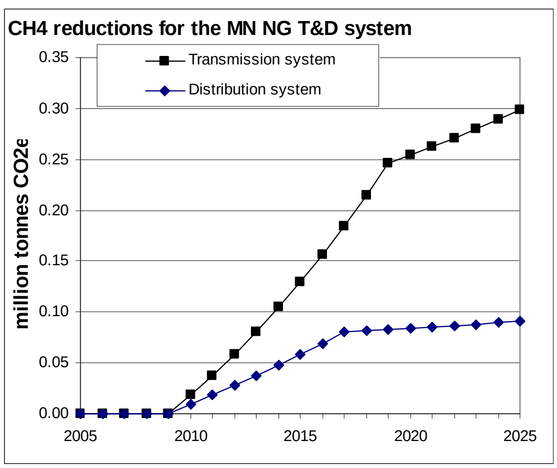
For the Minnesota natural gas transmission system, there were several mitigation option analyzed for their collective impact on reducing methane leaks, as follows:

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

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

- Directed Inspection and maintenance at gate stations and surface facilities

Regarding CO_2e emissions reductions, the impact of the collective options is summarized in the chart below. 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 million tonnes CO_2e, respectively. The cumulative emission reductions over the 2010–2025 forecast period are 3.9 million tonnes CO_2e.



Regarding the annual costs of the option, there are incremental costs from biomass associated with capital improvements, O&M, and fuel for each of the options considered. There are incremental savings associated with the value of the natural gas emissions avoided. The net present value of these annual costs are –$0.093 billion over the 2010–2025 period (2005$).

Regarding the cost-effectiveness of the option, it was calculated as the quotient of the NPV and cumulative GHG emission reductions, –$26/t CO_2e (2005$) (i.e., –$0.093 billion divided by 3.9 million tonnes and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 2

Key Uncertainties

The proposal would need to be integrated with the existing Cap-X 2020 program.

Additional Benefits and Costs

None.

Feasibility Issues

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

Status of Group Approval

Pending—[until MCCAG moves to final agreement at meeting #8]

Level of Group Support

TBD—[blank until MCCAG meeting #8]

Barriers to Consensus

TBD—[blank until final vote by the MCCAG]

ES-5. Renewable and/or Environmental Portfolio Standard

Policy Description

A portfolio standard policy can be designed to require that a sector (Electricity Supply, Transportation, Industrial/Manufacturing and Commercial/Residential buildings) 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) is a requirement that utilities and other load-serving entities must 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 can include energy efficiency improvements or other GHG emission-reducing technologies (such as combined heat-and-power [CHP]) as an eligible resource. About 20 states currently have an RPS in place, while 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 objective of 25% by 2025.

Policy Design

Goals:

- Evaluate what GHG reductions will be realized by the Renewable Energy Standard 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 hydro, biomass and the use of 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/environmental (low CO_2 emitting) energy that reduces CO_2/GHG emissions (e.g., U of M IREE)
- Evaluate Performance Standards (Carbon Intensity Target) for renewable/environmental energy use by Residential, Commercial and Industrial entities.

Timing: Assume that current legislation will cover the time period from current to 2025. Legislation should be enacted by 2009 to give time for planning to meet any new standards. Funding for Renewable/Environmental R&D should begin as soon as practicable.

Parties Involved: M-RETS, Minnesota Public Utilities Commission, Minnesota State Legislature, Minnesota Department of Commerce

Implementation Mechanisms

Requires future legislation covering period from 2025 to 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.
- 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 like 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

- Energy Information Administration, "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
- National Energy Technology Laboratory, "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 is based on Form EIA-906 (available at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html
- Minnesota Next Generation Energy Bill; Article 5, Section 2, lines 41.2 and following.

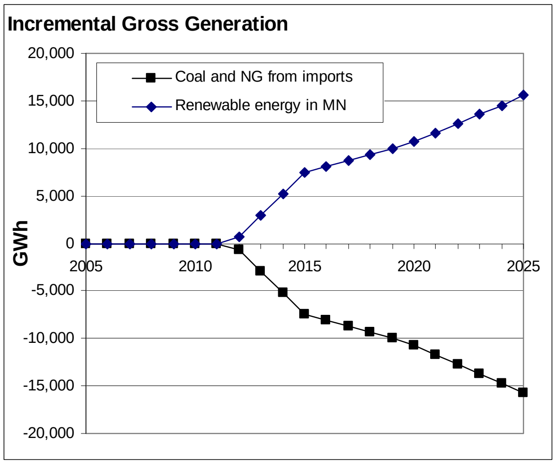
Quantification Methods:

This option is a policy to require that utilities and other load-serving entities must supply a certain, generally fixed, percentage of electricity from eligible (e.g., low GHG emitting) renewable energy sources. The current Minnesota statue through the year 2025—25% renewable energy as a percentage of sales—was modeled.

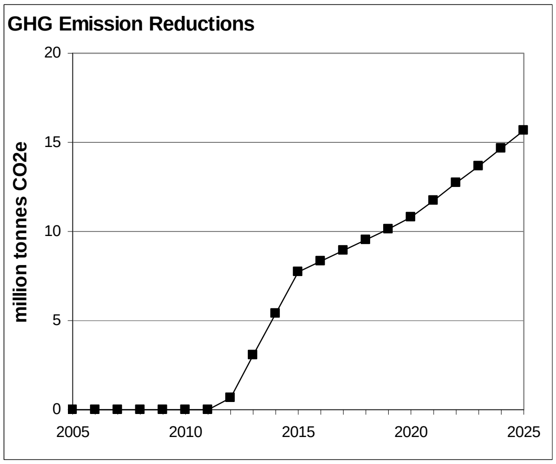
The TWG has made the following key assumptions for the analysis of this option, as follows:

- The start year for the option 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 NG-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). Capital costs of non-depreciated units were assumed to be one-third of 2005 costs.

Regarding generation, the impact of the option is summarized in the chart below. The upper curve represents the total incremental generation associated with the RES in Minnesota and the lower curve represents incremental displaced coal/NG-fired generation outside Minnesota.



Regarding CO_2e emission reductions, the impact of the option is summarized in the chart below. The annual emission reductions in 2015 and 2025 are 7.7 and 15.7 million tonnes CO_2e, respectively. The cumulative emission reductions over the 2011–2025 forecast period are 133.1 million tonnes CO_2e.



Regarding costs, 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-fired and NG-fired was assumed to be $92/MWh and $217/MWh, respectively (2005). There are incremental costs associated with capital costs, transmission costs, variable O&M costs, fixed O&M costs and fuel costs associated with the RES. The annual product of real levelized costs and displaced generation is an estimate of the annual costs. The net present value of these annual costs are $4.7 billion over the 2011–2025 period (2005$).

Regarding the cost-effectiveness of the option, it was calculated as the quotient of the NPV and cumulative GHG emission reductions, $35.5/t CO_2e (2005$) (i.e., 4.7 billion divided by 133.1 million tons and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 2

Key Uncertainties

Costs of renewable energy technologies; price forecast for natural gas and coal delivered to regional power stations; portion of backed down generation which is full 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

Approved.

Level of Group Support

Approved.

Barriers to Consensus

None.

ES-6. Nuclear Power Support and Incentives

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 would be 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., one 1,100 MW unit installed in Minnesota in the post-2025 period*.

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

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

Implementation Mechanisms

The planning requirements would be implemented through the Integrated Resource Planning (IRP) process already implemented by the Public Utilities Commission. Thorough consideration of the safety, economics, and environmental implications of nuclear power would be explicitly called for.

In addition, the ongoing work at 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 requirements (see above). These 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. In the event that a comprehensive GHG policy were implemented in the state's electric power sector, it would 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:

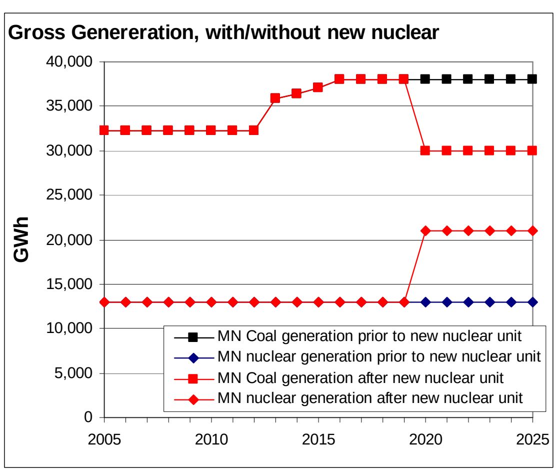
- Energy Information Administration, "Assumptions to the Annual Energy Outlook 2007," DOE/EIA-0554, April 2007, available at: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf)
- Capital cost, transmission, fixed O&M and variable O&M escalation factors developed by the ES TWG

Quantification Methods:

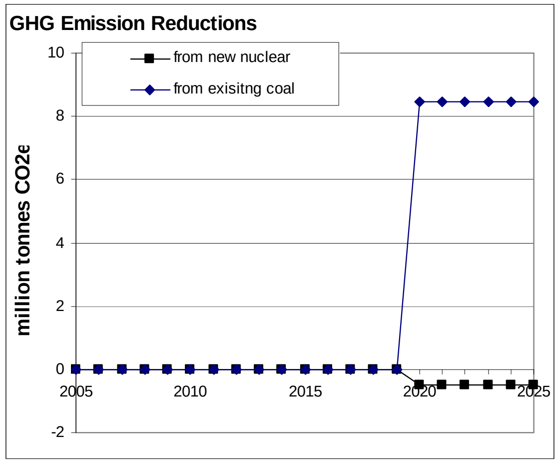
This option would provide support and incentives for life extension at existing nuclear power plants and for study of potential new nuclear power plants in Minnesota. Since the policy calls for the installation of a new unit in the post-2025 time frame, it is a non-quantified option. As a sensitivity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

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

Regarding generation, the impact of the option is summarized in the chart below. The upper curve represents the total Minnesota coal generation before and after the introduction of the new nuclear station. The lower curve represents the total Minnesota nuclear generation before and after the introduction of the new nuclear station.



Regarding CO_2e emission reductions, the impact of the option is summarized in the chart below. 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 million tonnes CO_2e, respectively. The cumulative net emission reductions over the 2005–2025 forecast period are 47.8 million tonnes CO_2e.



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

Regarding the cost-effectiveness of the option, it was calculated as the quotient of the NPV and cumulative GHG emission reductions, $70.2/t CO_2e (2005$) (i.e., 3.4 billion divided by 47.8 million tonnes and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 2

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

Pending—[until MCCAG moves to final agreement at meeting #8]

Level of Group Support

TBD—[blank until MCCAG meeting #8]

Barriers to Consensus

TBD—[blank until final vote by the MCCAG]

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

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, North and South Dakota) should strive to have at least two IGCC projects with CCS 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, IPPs, state regulators.

Implementation Mechanisms

- Technology demonstrations—Critical to have commercial scale 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. There are three demonstrations 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 CCS 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 stat financial incentives (tax credits, loan guarantees, etc.)
- 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 research and development programs and investments, with a focus on developing the gasification and carbon sequestration industries.
- 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 same. 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 CCS, including when transported via pipeline for use in enhanced oil recovery operations.

Related Policies/Programs in Place

In 2003 the Minnesota Legislature enacted two statues—Minnesota Stat. 216B.1693 (the "Clean Energy Technology Statue") and Minnesota Stat. 216B. 1694 (the Innovative Energy Project Statue")—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 emissions of carbon dioxide from coal combustion.

Estimated GHG Reductions and Net Costs or Cost Savings

- Energy Information Administration, "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
- National Energy Technology Laboratory, "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 is based on Form EIA-906, available at: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html
- Intergovernmental Panel on Climate Change (IPCC), "Carbon Capture and Storage," 2006.
- "The Future of Coal: Options for a Carbon-Constrained World, MIT, 2007, available at http://web.mit.edu/coal/The_Future_of_Coal.pdf

Quantification Methods:

This option considers the role that coal could play in Minnesota's future energy system, providing 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 and storage.

The TWG has considered a primary analysis and two sensitivity analyses as follows:

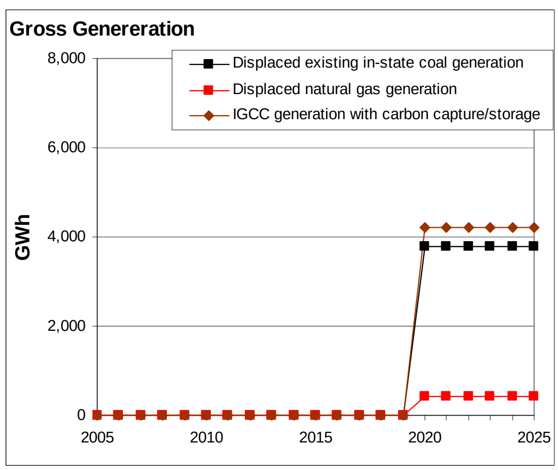
- *Primary analysis:* new IGCC with carbon capture and storage (CCS)
- *Sensitivity analysis #1:* new IGCC without CCS
- *Sensitivity analysis #2:* retrofit of existing coal stations with CCS
- *Sensitivity analysis #3:* new IGCC with 1% biomass co-firing and carbon capture and storage (CCS)

Primary analysis: new IGCC with carbon capture and storage

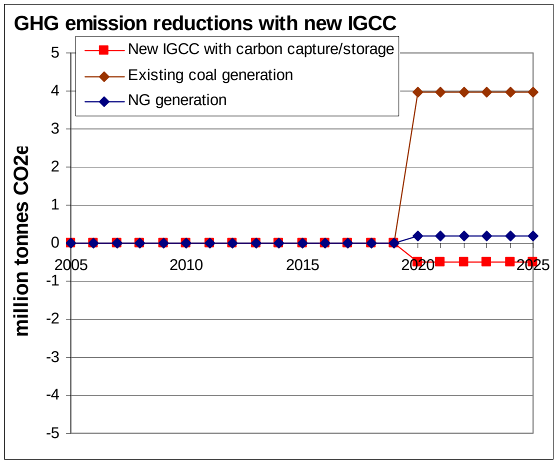
The TWG has made the following key assumptions for the analysis of this option, as follows:

- The start year for the option 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 CCS technology.
- A carbon capture efficiency of 86% is assumed from adding CCS technology.
- Assumes a geologic storage site within 150 miles of the IGCC unit connected by a pipeline with a mass flow rate of 22.5 Mt CO_2/yr.

Regarding generation, the impact of the option is summarized in the chart below for both new and displaced resources.



Regarding CO_2e emission reductions, the impact of the option is summarized in the chart below. 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. The lower curve represents the annual CO_2e emission increases associated with the generation from the new IGCC with CCS power station in Minnesota. The net annual emission reductions in 2025 are 3.66 million tonnes CO_2e. The cumulative emission reductions over the 2020–2025 forecast period are 21.96 million tonnes CO_2e.



Regarding costs, 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 in Minnesota and outside Minnesota. There are incremental costs associated with new IGCC with CCS 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 net present value of these annual costs are $3.506 billion over the 2020–2025 period (2005$).

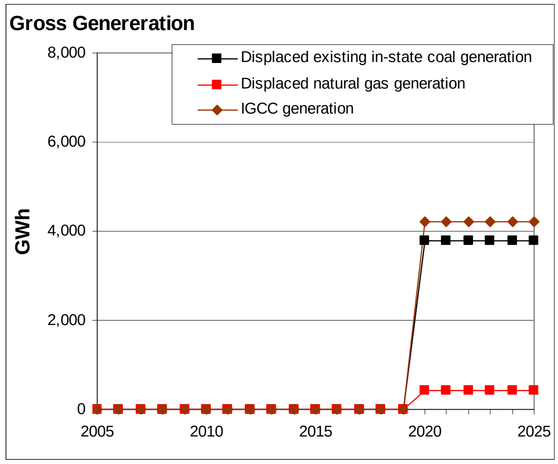
Regarding the cost-effectiveness of the option, it was calculated as the quotient of the NPV and cumulative GHG emission reductions, $159.7/t CO_2e (2005$) (i.e., $3.506 billion divided by 21.96 million tonnes and multiplied by a conversion factor of 1,000).

Sensitivity analysis #1: new IGCC without carbon capture and storage

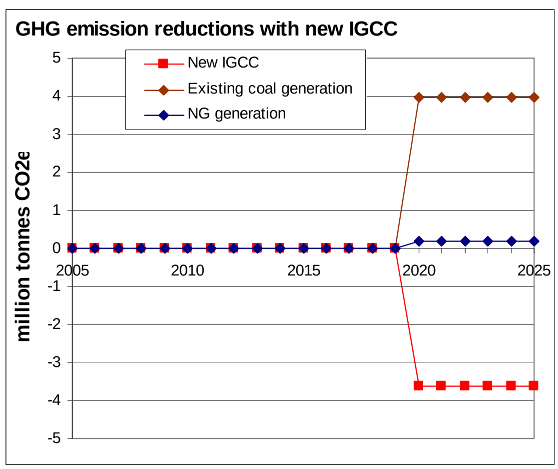
The TWG has made the following key assumptions for the analysis of this option, as follows:

- The start year for the option 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.

Regarding generation, the impact of the option is summarized in the chart below for the new and displaced resources.



Regarding CO_2e emission reductions, the impact of the option is summarized in the chart below. 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. 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 million tonnes CO_2e, respectively. The cumulative emission reductions over the 2020–2025 forecast period are 3.2 million tonnes CO_2e.



Regarding costs, 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 in Minnesota and outside Minnesota. There are incremental costs associated with new IGCC 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 net present value of these annual costs are $1.95 billion over the 2020–2025 period (2005$).

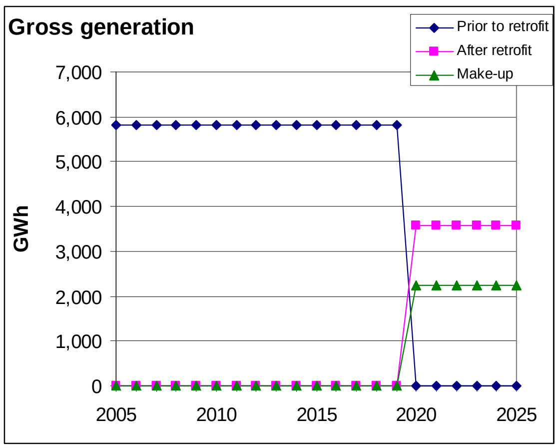
Regarding the cost-effectiveness of the option, it was calculated as the quotient of the NPV and cumulative GHG emission reductions, $606.5/t CO_2e (2005$) (i.e., $1.95 billion divided by 3.2 million tonnes and multiplied by a conversion factor of 1,000).

Sensitivity analysis #2: retrofitting existing pulverized coal stations with carbon capture and storage

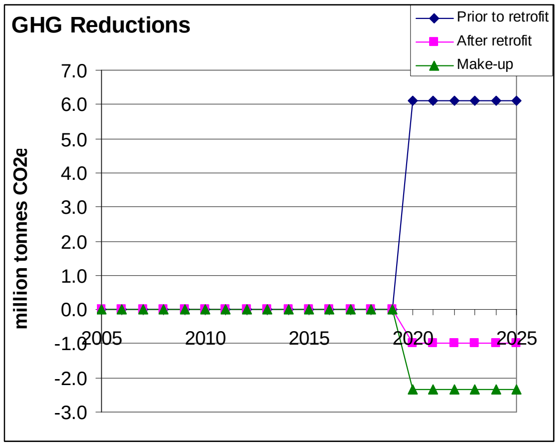
The TWG has made the following key assumptions for the analysis of this option, as follows:

- The start year for the option 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 derating of 41% is assumed for MEA and 36% for oxygen-firing. Make-up power is assumed available from in-state pulverized coal stations.
- Carbon capture efficiencies are assumed to be 83% for MEA and 84% for oxygen-firing.
- Assumes a geologic storage site within 150 miles of the units connected by a pipeline with a mass flow rate of 22.5 Mt CO_2/yr.

Regarding generation, the impact of the option is summarized in the chart.



Regarding CO_2e emission reductions, the impact of the option is summarized in the chart below. 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. 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 million tonnes CO_2e, respectively. The cumulative emission reductions over the 2020–2025 forecast period are 16.7 million tonnes CO_2e.



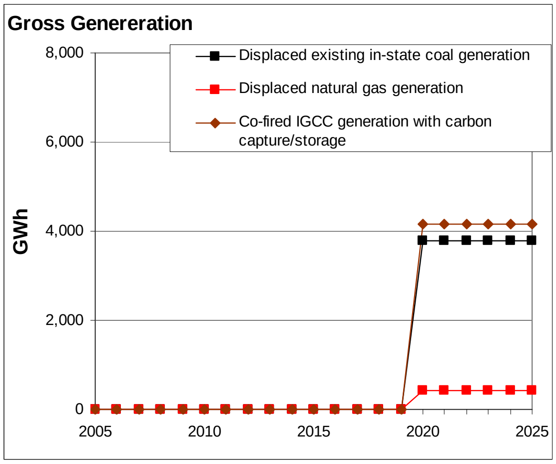
Regarding costs, there are incremental costs associated with retrofitting, namely incremental capital costs, variable O&M costs, fixed O&M costs and fuel costs. The annual product of real levelized costs and displaced generation is an estimate of the annual costs. The net present value of these annual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

Regarding the cost-effectiveness of the option, it was calculated as the quotient of the NPV and cumulative GHG emission reductions, $97.2/t CO_2e (2005$) (i.e., 1.6 billion divided by 16.7 million tonnes 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 TWG has made the following key assumptions for the analysis of this option, as follows:

- The start year for the option 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 CCS technology.
- A carbon capture efficiency of 86% is assumed from adding CCS technology.
- Assumes a geologic storage site within 150 miles of the IGCC unit connected by a pipeline with a mass flow rate of 22.5 Mt CO_2/yr.
- Coal is co-fired with biomass at 1% on an energy basis

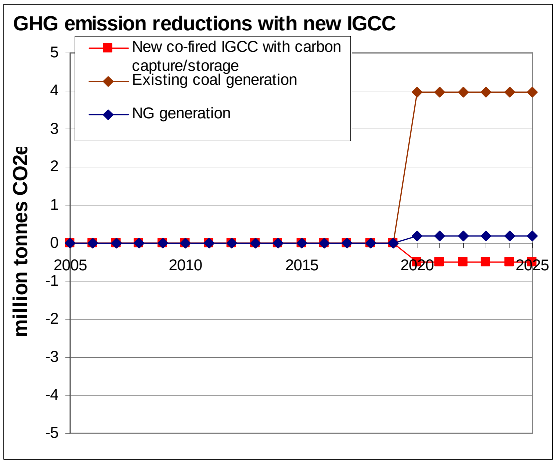
Regarding generation, the impact of the option is summarized in the chart below for both new and displaced resources. The total level of generation associated with the biomass portion of output from the IGCC unit is 42 GWh from 2020 through 2025.



Regarding CO_2e emission reductions, the impact of the option is summarized in the chart below. 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. The lower curve represents the annual CO_2e emission increases associated with the generation from the new IGCC with CCS power station in Minnesota.

An annual total of 0.04 million tonnes 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 as biomass is assumed to be used in a sustainable manner. Cumulatively, 0.26 million tones of biogenic CO_2e emissions are captured and stored at the geologic storage site.

The net annual emission reductions in 2025 are 3.71 million tonnes CO_2e. The cumulative emission reductions over the 2020–2025 forecast period are 22.25 million tonnes CO_2e.



Regarding costs, 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 in Minnesota and outside Minnesota. There are incremental costs associated with new IGCC with CCS 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 net present value of these annual costs are $3.515 billion over the 2020–2025 period (2005$).

Regarding the cost-effectiveness of the option, it was calculated as the quotient of the NPV and cumulative GHG emission reductions, $158.0/t CO_2e (2005$) (i.e., $3.515 billion divided by 22.25 million tonnes and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 2.

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

Technology currently in demonstration stage.

Status of Group Approval

Pending—[until MCCAG moves to final agreement at meeting #8]

Level of Group Support

TBD—[blank until MCCAG meeting #8]

Barriers to Consensus

TBD—[blank until final vote by the MCCAG]

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

Policy Description

Distributed renewable energy should be encouraged as 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 small-scale distributed renewable energy via incentives and/or the prevention of barriers. Incentives for distributed renewables should include: (1) direct subsidies for purchasing/selling renewable technologies; (2) tax credits or exemptions for purchasing/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 count toward the Conservation Improvement Program (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 to 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 (IOUs, municipals 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

Renewable Energy Standard 25 × 25. Existing matching programs for investment in photovoltaic systems. Wind production tax credits.

Type(s) of GHG Reductions

Reductions in emissions of carbon dioxide from combustion sources.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources:

- Annual Estimates of Housing Units for the United States and States: April 1, 2000 to July 1, 2005, available at U.S. Census Bureau annual data, released at the end of every July: http://www.census.gov/popest/housing/HU-EST2005.html
- New Privately Owned Housing Units, Authorized Unadjusted Units for Regions, Divisions, and States, U.S Census Bureau annual data, released end of every July, available at http://www.census.gov/const/C40/Table2/t2yu200512.txt
- 2001 EIA Residential Energy Consumption Survey, available at http://www.eia.doe.gov/emeu/recs/recs2001/detailcetbls.html#space
- Ratios of new residential/commercial floor space to total floor space, from EIA, available at http://www.eia.doe.gov/emeu/cbecs/excel/b1.xls
- Cooling degree-days in Minnesota, available from http://lwf.ncdc.noaa.gov/oa/documentlibrary/hcs/cdd.200501-200607.pdf
- Heating degree-days in Minnesota, available from Department of Commerce (http://lwf.ncdc.noaa.gov/oa/documentlibrary/hcs/hdd.200507-200607.pdf)
- Minnesota population projection, Minnesota State Demographic Center, available from http://www.demography.state.mn.us/documents/MinnesotaPopulationProjections20052035.pdf
- Utility electricity sales in 2005, available from U.S Energy Information Administration at http://www.eia.doe.gov/cneaf/electricity/page/eia826.html
- Sectoral electricity consumption, from EIA, available from U.S. Energy Information Administration at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html (file sales_revenue.xls)
- The 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, January, 2006, http://www.westgov.org/wga/initiatives/cdeac/Energy%20Efficiency-full.pdf

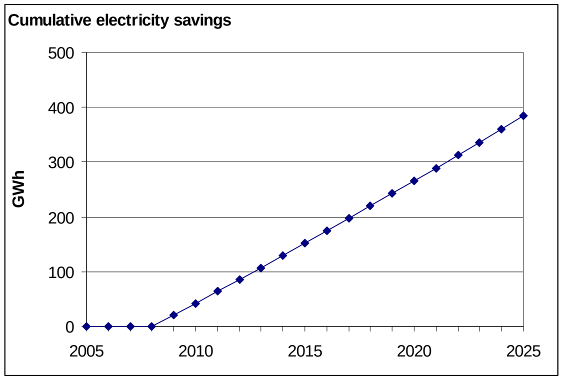
Quantification Methods:

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

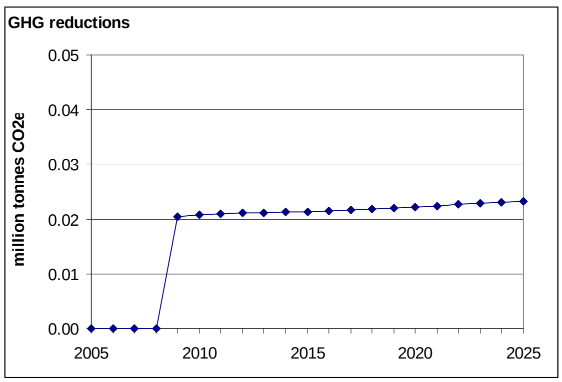
The ES TWG has made the following key assumptions for the analysis of this option, as follows:

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

Regarding generation, the chart below summarizes the cumulative savings associated with the penetration of distributed renewable energy in new residential and commercial units.



Regarding annual CO_2e emission reductions, the impact of the option is summarized in the chart below. The annual emission reductions in 2015 and 2025 are 0.021 and 0.023 million tonnes CO_2e, respectively. The cumulative emission reductions over the 2009–2025 forecast period are 0.37 million tonnes CO_2e.



Regarding costs, there are cost savings associated with avoided fuel and O&M at existing power stations in Minnesota. There are 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 net present value of these annual costs are $0.029 billion over the 2009–2025 period (2005$).

Regarding the cost-effectiveness of the option, it was calculated as the quotient of the NPV and cumulative GHG emission reductions, $78.1/t CO_2e (2005$) (i.e., $0.029 billion divided by 0.37 million tonnes and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 2.

Key Uncertainties

TBD—[as needed and approved by the TWGs]

Additional Benefits and Costs

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

Feasibility Issues

Structuring of the incentive.

Status of Group Approval

Pending—[until MCCAG moves to final agreement at meeting #8]

Level of Group Support

TBD—[blank until MCCAG meeting #8]

Barriers to Consensus

TBD—[blank until final vote by the MCCAG]

Annex 2: 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	/ariable 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 cycle	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

Stages of coal fuel cycle	Considered?	MMbtu input per MMBtu of coal delivered to the power station: 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

Stages of coal fuel cycle	Considered?	Additional tonnes CO2e per MMBtu associated with upstream fuel cycle stages: 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

	Cost and performacne assumptions					First Year Non-Fuel Values							
						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

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
Capacture 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&	riable 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. Renewable 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

	Housing unit estimates						April 1, 2000	
Geographic Area	**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