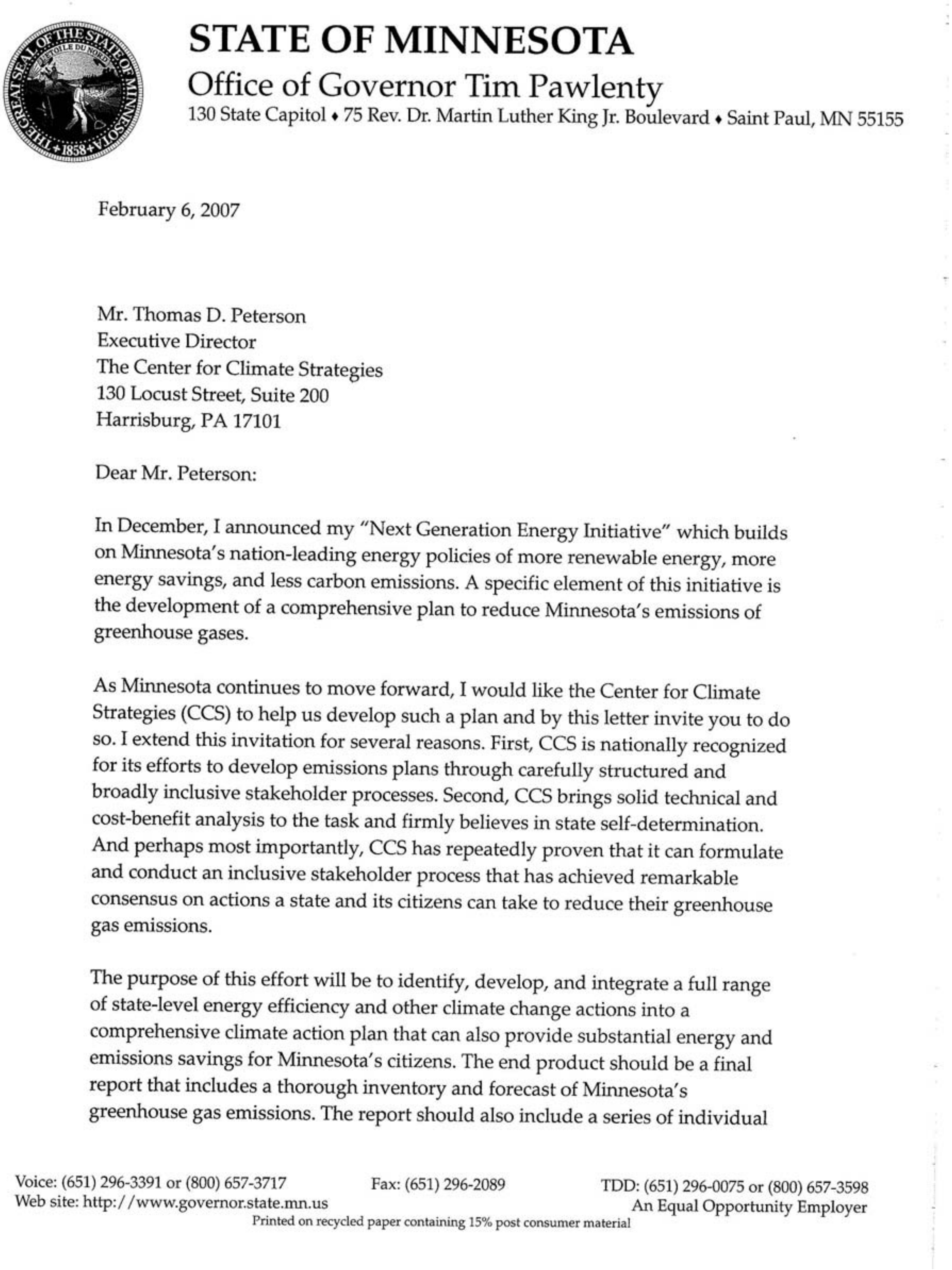
Appendix A
Letter From Governor Pawlenty



STATE OF MINNESOTA
Office of Governor Tim Pawlenty
130 State Capitol ♦ 75 Rev. Dr. Martin Luther King Jr. Boulevard ♦ Saint Paul, MN 55155

February 6, 2007

Mr. Thomas D. Peterson
Executive Director
The Center for Climate Strategies
130 Locust Street, Suite 200
Harrisburg, PA 17101

Dear Mr. Peterson:

In December, I announced my "Next Generation Energy Initiative" which builds on Minnesota's nation-leading energy policies of more renewable energy, more energy savings, and less carbon emissions. A specific element of this initiative is the development of a comprehensive plan to reduce Minnesota's emissions of greenhouse gases.

As Minnesota continues to move forward, I would like the Center for Climate Strategies (CCS) to help us develop such a plan and by this letter invite you to do so. I extend this invitation for several reasons. First, CCS is nationally recognized for its efforts to develop emissions plans through carefully structured and broadly inclusive stakeholder processes. Second, CCS brings solid technical and cost-benefit analysis to the task and firmly believes in state self-determination. And perhaps most importantly, CCS has repeatedly proven that it can formulate and conduct an inclusive stakeholder process that has achieved remarkable consensus on actions a state and its citizens can take to reduce their greenhouse gas emissions.

The purpose of this effort will be to identify, develop, and integrate a full range of state-level energy efficiency and other climate change actions into a comprehensive climate action plan that can also provide substantial energy and emissions savings for Minnesota's citizens. The end product should be a final report that includes a thorough inventory and forecast of Minnesota's greenhouse gas emissions. The report should also include a series of individual

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policy recommendations across all sectors and types of activities, recommended statewide goals for reduction, and a plan for implementation. I ask that the end product be delivered by January 2008.

Beginning immediately, I ask CCS to facilitate and provide technical support to this process in partnership and coordination with my office and designated state agencies. All efforts should be coordinated through Deputy Commissioner Edward Garvey at the Minnesota Department of Commerce.

I also ask CCS to provide cost sharing assistance to ensure that Minnesota's process reflects an effort which is inclusive, transparent, and advanced in terms of consensus building and technical analysis. In keeping with this request, please develop a detailed technical work plan for my review and approval, including organizational details, budget plans, and funding requirements.

I appreciate your assistance in this important matter.

Sincerely,

Tim Pawlenty
Governor

Appendix B
Description of Climate Change Advisory Group Process

This appendix contains a memo by the Center for Climate Strategies describing the facilitated stakeholder process that the CCAG would follow. This memo was originally presented at the first meeting of the CCAG on April 20, 2007. It was revised during preparation of the final report to incorporate two additional MCCAG meetings, the addition of the Cap-and-Trade TWG, extension of the period for analyses from 2020 to 2025, and staffing changes that occurred during the MCCAG process as approved by the MCCAG and DOC/PCA.

Memorandum

To: Minnesota Climate Change Advisory Group (MCCAG) Members

From: The Center for Climate Strategies

CC: Minnesota Department of Commerce (DOC)
Minnesota Pollution Control Agency (PCA)

Re: Minnesota Climate Change Action Plan Process

Date: April 20, 2007

Forming the Minnesota Climate Change Advisory Group

On December 12, 2006, Minnesota Governor Tim Pawlenty announced the state's "Next Generation Energy Initiative," including "development of a comprehensive plan to reduce Minnesota's emissions of greenhouse gas (GHG) emissions." In this announcement, the Governor requested assistance from the Center for Climate Strategies (CCS) in the development of a Minnesota Climate Mitigation Action Plan (Action Plan) and formation of the Minnesota Climate Change Advisory Group (MCCAG). This broad-based group of Minnesota citizens and leaders is charged with developing a comprehensive set of state-level policy recommendations to the Governor through a stakeholder-based consensus building process that will be facilitated by CCS in coordination with the Minnesota Department of Commerce (DOC) and Minnesota Pollution Control Agency (PCA).

Development of a Minnesota Climate Change Action Plan

To develop the Action Plan as directed by the Governor, the MCCAG is tasked with completion of the following specific planning recommendations:

1. Review and approval of a current and comprehensive inventory and forecast of GHG emissions in Minnesota from 1990 to 2025;

2. Development and recommendation of a comprehensive set of specific policy recommendations and associated analyses to reduce GHG emissions and enhance energy and economic policy in Minnesota by 2025 and beyond;
3. Development and recommendation of a set of statewide GHG reduction goals and targets for implementation of these actions; and
4. Issuance of recommendations in the form of a final report to the Governor by March 2008.

The Center for Climate Strategies (CCS) will work in partnership with DOC and PCA to provide facilitation and technical support for a process to complete these tasks through joint activities of the MCCAG, a set of Technical Work Groups (TWGs), state agencies, and members of the public. A detailed work plan and description of the Action Plan process follows.

Final MCCAG Report

By March 8, 2008, CCS will provide a final MCCAG report to the Governor. It will compile and summarize final recommendations of the MCCAG and cover the following areas:

1. Executive Summary
2. History and Status of State Actions
3. Inventory and Forecast of Minnesota GHG Emissions
4. Recommended Policy Actions by Sector:
   a. Energy Supply
   b. Residential, Commercial and Industrial
   c. Transportation and Land Use
   d. Agriculture, Forestry and Waste Management
   e. Cross-Cutting Issues (inventory and forecast, emissions reporting, registries, education, statewide goals, etc.)
   f. Cap-and-Trade
5. Technical Appendixes

Timing and Milestones

The first meeting of the advisory group will be held April 20, 2007 with seven additional meetings and a final report to be completed by March 2008. Two or more TWG conference calls per each of the five TWGs will be held between each of the advisory group meetings according to the following schedule.

MCCAG Calendar

Date	Action
February 16, 2007	Executive Order and Announcement
April 20, 2007	1st MCCAG meeting
June 14, 2007	2nd MCCAG meeting
August 2, 2007	3rd MCCAG meeting
September 27, 2007	4th MCCAG meeting
November 8, 2007	5th MCCAG meeting
December 5, 2007	6th MCCAG meeting
January 10, 2008	7th MCCAG meeting
January 24, 2008	8th MCCAG meeting
March 8, 2008	Final MCCAG Report Due
Between MCCAG Meetings	TWG conference calls and meetings

Design of the Action Plan Process

The Action Plan process will follow the format of several state climate action planning processes conducted by CCS (available through www.climatestrategies.us). This consensus building model combines techniques of alternative dispute resolution, community collaborative decision-making, and corporate strategic planning in a combined form of facilitation and technical analysis known as “evaluative facilitation.” The process fully integrates group decisions and technical analysis through open, informed, and collaborative decision making and self determination by a broadly representative group of stakeholders (the MCCAG), with the support of TWGs. Activities of the MCCAG will be transparent, inclusive, stepwise, fact-based, and consensus driven (see key principles and guidelines of the process listed below). The process will *seek but not mandate consensus* on individual policy option recommendations and will use formal voting processes by the MCCAG to identify potential objections and alternatives.

The Action Plan process relies on intensive use of information and interaction between facilitators, participants, and technical analysts. The CCS team provides close coordination of MCCAG, TWG, facilitation, and technical support activities. To facilitate learning, collaboration, and task completion by the MCCAG and TWGs, CCS will provide a series of discussion and decision templates for each step in the process, including:

- A public website for all information and proceedings of the process at http://www.mnclimatechange.us/;
- Standard meeting documents, including: agenda and notice, discussion PowerPoint, meeting summary, and reference document(s) formatted for each of the MCCAG and TWG meetings;
- A draft report, PowerPoint presentation, and series of worksheets for review and approval of the Minnesota GHG emissions inventory and forecast;

- An initial master catalog of state GHG reduction actions with lay descriptions for each option, suggested ranking criteria, draft rank of potential for GHG reductions and costs or cost savings of each action, and indication of major recent actions already undertaken in Minnesota;
- An assessment of the emissions savings and other impacts of actions already adopted in Minnesota;
- A balloting form for identification of initial priorities for analysis for each of the TWG areas;
- A draft policy option template for the drafting and analysis of individual recommendations;
- A principles and guidelines document for quantification of policy options in each of the TWGs;
- Analysis materials, including documentation of key data sources, assumptions, models, and methods, and printouts of worksheets as needed; and
- A final report format with summary chapters and technical appendixes.

The MCCAG and TWG process includes the following key principles and guidelines:

- The process is fully transparent. All materials considered by the MCCAG and TWGs are posted to the project website, and all meetings are open to the public. For TWG meetings, which will be conducted telephonically, the state will arrange for physical locations with a telephone and a telephone monitor so that the public can listen. The quantification of all potential policy options is transparent with respect to the data sources, methods, key assumptions, and uncertainties. In addition, policy design parameters and implementation methods for recommended actions are fully transparent, including goal levels, timing, coverage of parties, and implementation mechanisms. The transparency of technical analysis, policy design, and participant viewpoints is critical to the identification and resolution of potential conflicts.
- The process is inclusive. A diverse group of MCCAG and TWG members are chosen by the Governor to represent a broad spectrum of interests and expertise in Minnesota. A ground rule for participation is to be supportive of the goals of the MCCAG and the process described here, but members are free to disagree on specific decisions within the process. The public will be afforded the opportunity to provide meaningful review of and comment upon pending MCCAG decisions.
- The process is stepwise. Each step of the sequential process builds incrementally on the prior one toward a final solution. Sufficient time, information, and interaction are provided between steps to ensure comfort with decisions and quality of results. Participants are responsible for staying current with information developed by and decisions of the process.
- The process will seek but not mandate consensus. Votes will be taken at each of the major milestones in the process in order to advance to next steps. Decisions are requested on individual policy options. Alternatives that address barriers to consensus will be developed by the MCCAG with the assistance of CCS, as needed. Voting is conducted by simple request for objection at the point of decision (by hand), followed by resolution of conflicts through discussion and development of alternatives, as needed, in order to proceed. Final votes by the MCCAG include support at three levels, including: Unanimous consent (no

objection), Super Majority (four objections or less), and Majority (less than half object). (Typically, the early stages of the process proceed with unanimous consent, and super majority, if needed. Final recommendations may include recommendations at all three levels. Typically, most, if not all, final recommendations enjoy unanimous consent.) The final report will document the level of support for individual MCCAG recommended options, including alternative views as needed.

- The process is comprehensive. The MCCAG will explore solutions in all sectors and across all potential implementation methods, including a variety of voluntary and mandatory implementation mechanisms. Recommendations may include state-level and multi-state actions (regional and national). Mitigation of all GHGs will be examined. Units will be expressed in million metric tons of carbon dioxide equivalent (MMtCO$_2$e). Similarly, all forms of energy supply and use and economic development are open for consideration as they relate to GHG mitigation actions. Significant actions taken by the executive or legislative branches during the process will be included as possible and needed in a reference case forecast of emissions.
- The process is guided by clear decision criteria for the selection and design of recommended actions. These include consideration of: (1) GHG reduction potential; (2) cost or cost savings per ton of GHG emissions removed; (3) co-benefits, including economic and energy policy improvements; and (4) feasibility issues (technical, economic, political, and institutional).
- The process is quantitative. Results of MCCAG decisions will include explicit descriptions of policy design parameters and results of economic analysis. Recommendations can include both quantified and non-quantified actions, with emphasis on quantification of GHG reduction potential and cost or cost savings for as many recommendations as possible. Additional quantification needs related to co-benefits or feasibility issues will be evaluated on a case-by-case basis pending MCCAG input and available resources.
- The process covers short-, medium-, and long-term periods of action. The period of analysis for emissions inventories and reference case projections will be 1990–2025. Emissions reduction options, related energy, and economic analysis will cover the present to 2025, with supplemental analysis as possible for longer periods.
- The process is implementation oriented. The goal of the process is ultimate adoption of specific policies by the State of Minnesota based on planning recommendations of the MCCAG and subsequent, more detailed analyses as needed. Accordingly, recommendations of the MCCAG are intended to support immediate policy adoption, but will not consist of the highly detailed issues related to programmatic implementation, rulemaking, institutional design, and feasibility.

The TWG process is fully integrated with the MCCAG. TWGs are comprised of members of the MCCAG and/or their staff, as well as additional technical members appointed by the Governor, and serve in an advisory role to the MCCAG. The TWGs will be structured around the following sectors: Transportation; Energy Supply; Residential, Commercial and Industrial; Agriculture, Forestry and Waste; and Cross-Cutting Issues.

The TWGs will perform the following tasks in assistance to the MCCAG:

- Review the Catalog of existing, planned and potential state actions and suggest additional state actions for MCCAG consideration;
- Suggest a list of initial priorities for analysis of policy actions for MCCAG consideration through a balloting process;
- Develop and suggest initial “straw proposals” for the design of individual policy actions (with CCS assistance), including goals, timing and coverage of parties for MCCAG consideration;
- Review proposals for the analysis of individual policy actions, including data sources, methods and key assumptions for MCCAG consideration;
- Assist with the identification and development of data and assumptions to assist CCS with analysis of individual policy actions for MCCAG consideration, as needed;
- Respond to requests by the MCCAG for the development of alternative design scenarios or analyses to address potential barriers to consensus;
- Review draft final text for policy actions and final report language with suggested changes as needed for consideration by the MCCAG.

CCS will provide a facilitation and technical analysis team to assist the TWGs and coordinate MCCAG and TWG activities. The state will fully coordinate any technical staff involvement with the CCS team to ensure consistency and alignment on technical issues. As with the MCCAG, the TWGs will not debate the science of climate change or the goals, but will instead focus on identifying specific actions, design and analyses for MCCAG consideration that allow Minnesota to achieve the goals of the Executive Order.

Key Steps and Milestones

The objectives and agendas for each of the MCCAG and TWG meetings are listed below, with notes regarding each decision of the MCCAG.

MEETING ONE

- Objectives:
  - Introduction to the process, presentation of preliminary fact finding (inventory and forecast of emissions, Catalog of state actions), formation of TWGs (no votes, however, MCCAG members should be prepared to select one or more work groups for participation), next steps.
- Agenda:
  - Introductions
  - Purpose and goals of the Action Plan process
  - Review of the components and ground rules of the process
  - Review of the history and status of state climate mitigation and related energy and commerce actions
  - Review of the draft Minnesota emissions inventory & forecast

    - Review of the draft Catalog of existing state climate mitigation actions, including Minnesota actions
    - Formation of TWG's, next meeting agenda, time, location, date
    - Public input and announcements

Interim work group calls will cover: 1) suggested revisions to the draft inventory and reference case projections, and 2) review and suggested modifications to the Catalog of policy options.

MEETING TWO

- Objectives:
    - Addition of potential actions to the draft Catalog of state actions (by vote); identification of potential revisions to the draft emissions inventory and forecast (by vote if/as needed)
- Agenda:
    - Review and recommended updates to the draft emissions inventory and forecast
    - Review and approval of additional actions to the Catalog of possible Minnesota actions
    - Discussion of the process for identifying initial policy option priorities for TWG analysis
    - Next meeting agenda, time, location, date
    - Public input and announcements

Interim work group calls will cover: 1) suggested revisions to the emissions inventory and reference case projections, as needed; and 2) early ranking of options in the Catalog and balloting for initial "priority for analysis" options.

MEETING THREE

- Objectives:
    - Review and approval of initial priorities for analysis of TWG identified policy options (by vote); review and approval of revisions to the emissions inventory and forecast (by vote if/as needed)
- Agenda:
    - Agreement on inventories and baseline forecasts revisions, with modifications as needed
    - Review and approval of TWG lists of initial policy priorities for analysis, with modifications as needed
    - Discussion of process for developing straw policy design proposals for analysis of priority policy options
    - Briefing on quantification methods for draft policy options
    - Next meeting agenda, time, location, date
    - Public input and announcements

Interim TWG calls will cover: 1) development of straw proposals for design parameters for individual options, and 2) next steps for analysis of options.

MEETING FOUR

- Objectives:

  - Review and approval of TWG suggested straw proposals for policy design (goals, timing, coverage of parties) (by vote); review and approval of any additions to the list of priority policy options for analysis, if/as needed (by vote); preparation for quantification phase of the process (briefing and discussion)
- Agenda:
  - Review and approval of straw proposals for policy design, with modifications as needed
  - Discussion and approval of additional priority policy options for analysis, if/as needed
  - Discussion of quantification principles and guidelines, key assumptions for TWG analysis of priority policy options
  - Next meeting agenda, time, location, date
  - Public input and announcements

Interim TWG calls will cover: 1) review of proposed quantification procedures for individual options, including proposed data sources, methods, assumptions; 2) review of first round of quantification results, identification of needs for revision as needed; and 3) identification of potential early consensus options for recommendation for MCCAG approval.

MEETING FIVE

- Objectives:
  - Review and approval of consensus policy recommendations (by vote); identification of specific barriers to consensus, and potential alternatives for non-consensus policy options (discussion).
- Agenda:
  - Review of the draft pending policy options list, with results of analysis and cumulative emissions reductions potential
  - Identification of early consensus policy options
  - Identification of barriers and alternatives for remaining options, with guidance for additional work on options to TWG's
  - Review of final report progress and plans
  - Next meeting agenda, time, location, date
  - Public input and announcements

Interim TWG calls will cover: 1) final revisions to alternative policy design and implementation mechanisms as needed, 2) final analysis of options and alternatives, and 3) final steps on formulation of cross cutting policy options and mechanisms.

MEETINGS SIX, SEVEN, and EIGHT

- Objectives:
  - Review and approval of final policy option recommendations (by vote); review of final report procedures.
- Agenda:

- Review of the draft pending policy options list, with results of analysis and cumulative emissions reductions potential
- Review and final approval of draft pending policy options, with revisions as needed
- Summary of the process, review of next steps for completion and transmittal of the final report
- Public input and announcements

Participant Roles and Responsibilities

The MCCAG process involves a number of parties with specific roles and responsibilities, as follows:

Governor

The Governor convenes the process, appoints members and agency Chairs to the MCCAG, appoints members of the TWGs, receives nonbinding recommendations from the MCCAG through a report from CCS, and considers their implementation. The Governor also appoints a facilitation and technical support team (CCS), and agency representatives as needed to ensure that the process achieved the purpose and goals of his directive.

State Agencies

The process will be overseen and coordinated by DOC and PCA. State agency representatives serve as nonvoting members of the MCCAG, and participate in the TWGs. The state also provides technical and logistical support to MCCAG and TWG meetings and related activities in support of the CCS facilitator and TWG leaders. This includes logistical support for meetings, public notice, meeting summaries, and technical review and input to TWG meetings.

Center for Climate Strategies

CCS works in partnership with the state to design and conduct the MCCAG process and provides facilitation and technical support as an impartial and expert party. CCS manages and facilitates meetings and votes during meetings, schedules meetings in coordination with the state and Chair, develops meeting agendas, and produces documents for MCCAG and TWG consideration, including technical analysis.

CCS abides by the Model Standards of Conduct for Mediators approved by the American Arbitration Association, the Litigation Section, and the Dispute Resolution Section of the American Bar Association, and the Society of Professionals in Dispute Resolution. CCS also ensures that adequate funding exists to successfully complete the process through private sources. A project team is listed at the conclusion of this memo.

Climate Change Advisory Group

The MCCAG is appointed by the Governor to make nonbinding recommendations that include specific policy actions to reduce GHG emissions and provide positive energy and commerce opportunities. This includes a full range of potential mitigation options and recommended statewide goals, and approval of a final Minnesota GHG emissions inventory and forecast. MCCAG members are appointed to respond to the goals and timelines of the process. CCS facilitates MCCAG activities and votes in an open group format. The appointed Chair works in partnership with CCS to ensure timely and orderly completion of tasks, good faith participation and resolution of issues by MCCAG members. In coordination with CCS, the Chair enforces ground rules, opens, and closes MCCAG meetings.

Technical Work Groups

TWG members will be comprised primarily of MCCAG members assigned to specific sector based TWGs of interest by the state. They may include non-MCCAG individuals with technical expertise and interest of importance to the process. The TWGs provide guidance to MCCAG members on decisions related to milestones in the stepwise process. TWGs also assist CCS in the identification, design, and quantification of policy recommendations. Sector based TWGs include:

a. Energy Supply (heat and power)

b. Commercial, Industrial and Residential (energy efficiency and conservation, industrial process)

c. Transportation and Land Use

d. Agriculture, Forestry and Waste

e. Cross-Cutting Issues (inventory and forecast, emissions reporting, registries, education, statewide goals, etc.)

f. Cap-and-Trade

The Public

The public is invited to attend MCCAG and TWG meetings and provide review and input to members.

Participant Guidelines

MCCAG and TWG members are expected to follow certain codes of conduct during the process, including:

- Participants will not debate the science of climate change, the goals established in the Executive Order, or the timeline, but will instead provide leadership and a vision for how Minnesota will rise to the challenges and opportunities of addressing climate change.
- Participants are expected to support the process and its concept fully and, through the group process, in good faith collaborate toward the goals of the MCCAG and work groups.
- Participants are expected to act as equals during the process to ensure that all members have equal footing during deliberations and decisions.
- Participants must attend meetings and stay current with information provided to the group and the decisions of the group. Alternates are strongly discouraged and must be cleared with the facilitator and Chair. It is expected that alternates will not be routinely utilized. Any

alternate who does participate should be current with information developed by the process and able to make decisions.

- Participants will respect prior decisions made by the MCCAG in the stepwise process. Once the MCCAG reaches a milestone by consensus or vote, it will move to the next step.
- Each participant should speak only about their position and refrain from characterizing the views of others when making MCCAG decisions. Each MCCAG member must be able to vote or otherwise take a position at the meetings.
- When speaking about the process with the media or in other public settings, each MCCAG member must make clear they are representing only themselves, not the process, its convenors, or other participants.
- Participants are expected to provide objective, fact-based comments and alternatives during MCCAG and work group discussions, and must refrain from personal criticisms

Appendix C
Members of Technical Work Groups

* = Member of Minnesota Climate Change Advisory Group (MCCAG)
DOC = Minnesota Department of Commerce
PCA = Minnesota Pollution Control Agency
CCS = Center for Climate Strategies

RESIDENTIAL, COMMERCIAL, AND INDUSTRIAL

John Brandl, University of Minnesota, Humphrey Institute of Public Affairs*
John Carmody, University of Minnesota
Rick Carter, LHB, Inc.*
K.C. Chermak, Pillar Homes
Gary Connett, Great River Energy
Charles Dayton, Minnesota Center of Environmental Advocacy*
Ann Glumac, Glumac Executive Enterprise*
Jonathan Holmes, Mittal-Minorca*
John P. Kelly, Ryan Companies US, Inc.*
Jeffery Korsmo, Mayo Clinic, Rochester, Minnesota*
Cindy McComas, Minnesota Technical Assistance Program
Greg Miller, American Crystal Sugar*
Jeffry Muffat, 3M*
Pat Perry, Target Corporation*
Doug Peterson, Center Point Energy*
Joseph Steffel, Buffalo Public Utility
Sheldon Strom, Center for Energy and Environment
James Volanski, US Steel
Jeff Wilkes, Flint Hills Resources*
Mark Wolak, Superintendent, Mahtomedi, Minnesota*
Bruno Zagar, Fond du Lac Band, Lake Superior Chippewa*

Janet Streff, DOC Liaison
Bill Dougherty, CCS, Facilitator
Jeff Wennberg, CCS, Facilitator

ENERGY SUPPLY

Dr. Leith Anderson, Wooddale Church*
Alexander Bascom, Global Green Energy, LLC*
Barbara E. Freese, Union of Concerned Scientists*
Jerry Goodwald, Gerdau Ameristeel
Bill Grant, Izaak Walton League of America*
J. Drake Hamilton, Fresh Energy*
Bill Heaney, International Brotherhood of Electrical Workers*

Robert Jagusch, Mora Municipal Utilities*
Boise Jones, Environmental Justice Advocates of Minnesota*
Chuck MacFarlane, Ottertail Power Company*
Jim Marchessault, Business Card Services, Inc.*
Dave McMillan, ALLETE-Minnesota Power*
Eric Olsen, Great River Energy*
Steve Polaksy, University of Minnesota
Mike Robertson, Minnesota Chamber of Commerce*
David M. Sparby, Xcel Energy*
Will Steger, Polar Explorer [Ely, Minnesota]*
Richard Stone, Excelsior Energy
John Wachtler, Barr Engineering Company

Marya White, DOC Liaison
Bill Dougherty, CCS, Facilitator
Jeff Wennberg, CCS, Facilitator

TRANSPORTATION AND LAND USE

John Adams, University of Minnesota
Bishop Jon Anderson, Southwestern Minnesota Synod of the Evangelical Lutheran Church of America*
Daniel Bartholomay, McKnight Foundation*
John Brandl, University of Minnesota, Humphrey Institute of Public Affairs*
Jan Callison, Mayor, City of Minnetonka*
Gregory Dana, Auto Alliance
Laura Ekholm, L & M Radiator*
Jeremy Estenson, Minnesota Trucking Association
Anne Hunt, City of St. Paul
Eric Hyland, Auto Manufacturers
Julie Ketchum, Waste Management, Inc.*
Scott Lambert, Minnesota Auto Dealers*
Greg Langford, Langford, Inc.*
William Lee, Chippewa Valley Ethanol*
Tim McGraw, Northwest Airlines*
Dan Norrick, Cummins, Inc.
Pat Perry, Target Corporation*
Jeff Schoenwetter, JMS Companies
Peter J. Sullivan, GE Commercial Finance Fleet Service*
Barb Thoman, Transit for Livable Communities*
Christopher Twomey, Arctic Cat*
Mark Wegner, Twin Cities & Western Railroad

John Seltz, PCA
Will Schroeer, CCS, Facilitator
Lisa McNally, CCS, Facilitator

AGRICULTURE, FORESTRY, AND WASTE MANAGEMENT

Willis E. Anthony, Minnesota River Agricultural Team*
Peter Aube, Potlatch Forest Products Corporation*
Stacy Bohlen, Farm Bureau of Minnesota
Mitch Davis, Davisco Foods*
Joe Duggan, Pheasants Forever*
Stan Ellison, Shakopee Mdewakanton Sioux Community*
Tim Gieseke, Farmer, [New Ulm; Minnesota Project]
Shalini Gupta, Izaak Walton League of America
Mike Harley, Minnesota Environmental Initiative
Andy Hart, Farmer [Elgin, Minnesota]*
Bill Hunt, USDA Natural Resources Conservation Service*
Julie Ketchum, Waste Management, Inc.*
Jim Klienschmidt, Institute for Agriculture and Trade Policy
William Lee, Chippewa Valley Ethanol*
Joe Maher, UPM, Blandin Paper Mill*
Cheryl Miller, University of Minnesota
Greg Miller, American Crystal Sugar*
David Preisler, Minnesota Pork Producers
Steve Raukar, Commissioner, St. Louis County Board*
David Tilman, University of Minnesota Department of Ecology, Evolution, and Behavior*
Dave Zumeta, Forest Resources Council

Dave Richfield, PCA Liaison
Stephen Roe, CCS, Facilitator

CROSS-CUTTING ISSUES

Willis E. Anthony, Minnesota River Agricultural Team*
Alexander Bascom, Global Green Energy, LLC*
Bill Droessler, Minnesota Environmental Initiative
Ann Glumac, Glumac Executive Enterprise*
J. Drake Hamilton, Fresh Energy*
Scott Harrison, Lutsen Resort Company*
Bill Heaney, International Brotherhood of Electrical Workers*
Greg Jason, Cargill, Inc.*
Nancy Lange, Izaak Walton League of America
Jeffry Muffat, 3M*
Eric Olsen, Great River Energy*
Mike Robertson, Minnesota Chamber of Commerce*
Bob Schulte, Schulte Associates, LLC
David M. Sparby, Xcel Energy*
Will Steger, Polar Explorer [Ely, Minnesota]*
Sheldon Strom, Center for Energy and Environment
Peter J. Sullivan, GE Commercial Finance Fleet Service
Nirmal A. Traeger, St. Paul Travelers*

David Thornton, PCA Liaison
Tom Looby, CCS, Facilitator
Kenneth A. Colburn, CCS, Facilitator
Randy Strait, CCS, Facilitator

CAP-AND-TRADE

Alexander Bascom, Global Green Energy, LLC*
Deb Birgin, Missouri River Energy
Mitch Davis, Davisco Foods*
Charles Dayton, Minnesota Center for Environmental Advocacy*
Bill Droessler, Minnesota Environmental Initiative
Barbara E. Freese, Union of Concerned Scientists*
Bill Grant, Izaak Walton League of America*
J. Drake Hamilton, Fresh Energy*
Eric Hyland, Auto Manufacturers
Robert Jagusch, Mora Municipal Utilities*
Dave McMillan, ALLETE-Minnesota Power*
Jeffry Muffat, 3M*
Eric Olsen, Great River Energy* **Doug Peterson,** CenterPoint Energy*
Steve Polasky, University of Minnesota
Mike Robertson, Minnesota Chamber of Commerce*
Russle Sheaffer, Cummins Power, Inc.
Joseph Steffel, Buffalo Public Utility
Jim Turnure, Xcel Energy
Jeff Wilkes, Flint Hills Resources*

Edward Garvey, DOC Liaison
David Thornton, PCA Liaison
Tom Peterson, CCS, Facilitator
Jeff Wennberg, CCS, Facilitator

Appendix D
Greenhouse Gas (GHG) Emissions Inventory and Reference Case Projections

A separate report titled “Final Minnesota Greenhouse Gas Inventory and Reference Case Projections 1990–2025,” was used throughout the CCAG process to provide detailed documentation on emissions. The final version of this report, dated March 2008, incorporating comments provided by TWGs and approved by the CCAG, is available on the Climate Change Advisory Group’s Web site: http://www.mnclimatechange.us/ewebeditpro/items/O3F16231.pdf

Appendix E
Methods for Quantification

This appendix describes in brief the methods used in quantifying the greenhouse gas (GHG) emission reductions and costs / cost savings associated with the policy recommendations, and provides examples of the distinction between "direct" and "indirect" costs. In addition, the combined impacts of all of the policy recommendations within and between each sector were estimated as if all of the recommendations were implemented together. This involved eliminating any overlaps in coverage of affected entities that would occur to avoid double-counting of impacts. These methods are based on those widely accepted among climate change mitigation policy analysts.

Methods for Quantifying Impacts of Policy Recommendations

- **Focus of Analysis:** Net GHG reduction potential in physical units of million metric tons of carbon dioxide equivalent ($MMtCO_2e$) and net cost per metric ton reduced in units of dollars/tCO_2e.
- **Geographic Inclusion:** Measure GHG impacts of activities that occur within the state, regardless of the actual location of emissions reductions.
- **Direct vs. Indirect Effects:** Define "direct effects" as those borne by the entities implementing the policy recommendation. For example, direct costs are net of any benefits or savings to the entity. Define "indirect effects" as those borne by the entities other than those implementing the policy recommendation. Quantify these indirect effects on a case-by-case basis depending on magnitude, importance, need and availability of data. (See additional discussion and list of examples below.)
- **Non-GHG (Ancillary) Impacts and Costs:** Include in qualitative terms where deemed important. Quantify on a case-by-case basis as needed depending on need and where data are readily available.
- **Discounted and "Levelized" Costs:** Discount a multi-year stream of net costs (total costs net of any savings) to arrive at the "net present value cost" of an policy. Discount costs in constant 2005 dollars using a 5% annual real discount rate for the period 2008 through 2025. Capital investments are represented in terms of levelized or amortized costs through 2025. Create a "levelized" cost per ton by dividing the "present value cost" by the cumulative reduction in tons of GHG emissions. This is a widely used method to estimate the "dollars per ton" cost of reducing GHG emission (all in CO_2 equivalence). A "levelized" cost is a "present value average" used in a variety of financial cost applications.
- **Time Period of Analysis:** Count the impacts of actions that occur during the project time period and, using levelized emissions reduction and cost analysis, report emissions reductions and costs for specific target years such as 2015 and 2025. Where additional GHG reductions or costs occur beyond the project period as a direct result of actions taken during the project period, show these for comparison and potential inclusion.

- **Aggregation of Impacts:** Avoid simple double counting of GHG reduction potential and cost when adding emission reductions and costs associated with all of the policy recommendations. Note and or estimate interactive effects between policy recommendations using analytical methods where overlap is likely.
- **Policy Design Specifications:** Include timing, goal levels, implementing parties, and the type of implementation mechanism.
- **Transparency:** Include data sources, methods, key assumptions, and key uncertainties. Use data and comments provided by the Minnesota Climate Change Advisory Group (MCCAG) and Technical Work Groups (TWGs) to improve data sources, methods, and key assumptions using their expertise and knowledge to address specific issues in Minnesota.

The approaches here do not necessarily take a "standard" benefit-cost perspective as used in regulatory policy impact analysis. For instance, there is no direct/indirect distinction under standard procedures; one takes the "societal perspective" and tallies everything, and quantifies where possible. Regarding GHG mitigation costs, often the best available data are focused at the level of implementation as opposed to the societal level. Regarding GHG benefits, market prices (monetized benefits) are normally taken as good proxies of societal costs and benefits in standard analysis unless there are market imperfections or subsidies that create distortionary effects. Because accurate information on the dollar value of GHG reduction benefits is typically not available, physical benefits are used instead, measured as $MMtCO_2e$.

The "direct cost" approach described here is useful in estimating the costs (and benefits) to the implementing entity (e.g., person, company, governmental body, etc.) "Indirect costs" (and benefits) are those experienced by other entities in society. In examining utility demand-side management (DSM) programs for gas and electric utilities, analysts sometimes look at three perspectives: "participant," "non-participant," and "societal" (the latter being equivalent to "standard" benefit-cost perspective). Depending on program design, "direct cost" to a DSM participant can be high or low (if the latter, it may be attributable to a shifting of some costs to non-participants).

Note also that the "direct cost" approach does not necessarily account for market imperfections or subsidies. Typically, a state perspective on "direct costs" takes any federal government subsidies as a given. For example, substantial federal government subsidies exist for some alternative fuels. If the existing market price (with subsidy) of the alternative fuel is used in cost analysis, the option appears as relatively low cost. If the subsidy was included in the cost analysis (i.e., looking at societal costs in the standard benefit-cost perspective), then the alternative fuel would appear more costly.

For additional reference see the economic analysis guidelines developed by the Science Advisory Board of the US EPA available at: http://yosemite.epa.gov/ee/epa/eed.nsf/webpages/Guidelines.html.

Examples of Direct/Indirect Net Costs and Benefits

Note: These examples are meant to be illustrative. They are not necessarily included in the specific policy recommendations in this report.

Residential, Commercial, and Industrial (RCI) Sectors

Direct Costs and/or Benefits

- Net capital costs (or incremental costs relative to standard practice) of improved buildings, appliances, equipment (cost of higher-efficiency refrigerator versus refrigerator of similar features that meets standards)
- Net operation and maintenance (O&M) costs (relative to standard practice) of improved buildings, appliances, equipment, including avoided/extra labor costs for maintenance (less changing of compact fluorescent light (CFL) or light-emitting diode (LED) bulbs in lamps relative to incandescent)
- Net fuel (gas, electricity, biomass, etc.) costs (typically as avoided costs from a societal perspective)
- Cost/value of net materials use/savings (for example, raw materials savings via recycling, or lower/higher cost of low-global-warming-potential [GWP] refrigerants)

Indirect Costs and/or Benefits

- Re-spending effect on economy
- Net value of employment impacts
- Net value of health benefits/impacts
- Value of net environmental benefits/impacts (e.g., value of damage by air pollutants on structures, crops)
- Net embodied energy of materials used in buildings, appliances, equipment, relative to standard practice
- Improved productivity as a result of an improved working environment, such as improved office productivity through improved lighting (though the inclusion of this as indirect might be argued in some cases)

Energy Supply (ES) Sector

Direct Costs and/or Benefits

- Net capital and transmission costs (or incremental costs relative to reference case technologies) of renewables or other advanced technologies resulting from policies
- Net O&M costs (relative to reference case technologies) renewables or other advanced technologies resulting from policies
- Avoided or net fuel savings (e.g., gas, coal, biomass) of renewables or other advanced technologies relative to reference case technologies resulting from policies
- Total system costs (net capital + net O&M + avoided/net fuel savings + net imports/exports + net transmission and distribution [T&D] costs) relative to reference case total system costs

Indirect Costs and/or Benefits

- Re-spending effect on economy
- Higher cost of electricity reverberating through economy

- Energy security
- Net value of employment impacts
- Net value of health benefits/impacts
- Value of net environmental benefits/impacts (e.g., value of damage by air pollutants on structures, crops)

Agriculture, Forestry, and Waste Management (AFW) Sectors

Direct Costs and/or Benefits

- Net capital costs (or incremental costs relative to standard practice) of facilities or equipment (e.g., manure digesters and associated infrastructure, generator; ethanol production facility; composting facility; land acquisition or easement purchases; reforestation projects; urban tree planting programs)
- Net O&M costs (relative to standard practice) of equipment or facilities
- Net fuel (e.g., gas, electricity, biomass) costs or avoided costs
- Cost/value of net water use/savings or other avoided costs (e.g., avoided landfilling costs)

Indirect Costs and/or Benefits

- Net value of employment impacts
- Net value of human health benefits/impacts
- Net value of ecosystem health benefits/impacts (e.g., wildlife habitat; reduction in wildfire potential)
- Value of net environmental benefits/impacts (e.g., value of damage by air or water pollutants on structures, crops)
- Net value of fuel consumption derived from in-state production sources relative to standard sources
- Reduced VMT and fuel consumption associated with land use conversions (e.g., as a result of forest/rangeland/cropland protection policies)

Transportation and Land Use (TLU) Sectors

Direct Costs and/or Benefits

- Incremental cost of more efficient vehicles net of fuel savings.
- Incremental cost of implementing Smart Growth programs, net of saved infrastructure costs.
- Incremental cost of mass transit investment and operating expenses, net of any saved infrastructure costs or savings (e.g., roads)
- Incremental cost of alternative fuel, net of any change in maintenance costs

Indirect Costs and/or Benefits

- Health benefits of reduced air and water pollution.
- Ecosystem benefits of reduced air and water pollution.

- Value of quality-of-life improvements.
- Value of improved road safety.
- Energy security
- Net value of employment impacts

Methods for Quantifying Cumulative Impacts of Overlapping Policy Recommendations

In addition to estimating the impacts of each individual policy recommendations, *combined* impacts of the policy recommendations in each sector were estimated assuming that all were implemented together. This involved eliminating any overlaps in coverage that would occur to avoid double-counting of impacts. Also, some of the policy recommendations in one sector overlapped with policy recommendations in another sector; therefore, these overlaps were identified and the impact analysis was adjusted to eliminate double counting of impacts associated with these inter-sector overlaps. The following identifies where these overlaps occurred and explains the methods used to adjust the impacts analysis to avoid double counting of impacts.

RCI Cumulative Impacts Analysis Methodology

In order to assess the cumulative emissions reductions for the policies in the RCI sectors, it is necessary to consider any overlaps among the policies that affect similar types of energy use. Specifically, some policies (such as RCI-1) are defined by their usage reduction goals, while others are defined by addressing a specific type of energy use. In these cases it is important to consider whether addressing the specific energy use would add to the overall reductions, or just be subsumed into the more general reduction goal.

In order to address this issue, two approaches were used to determining whether a policy recommendation would have an incremental impact over and above the more general DSM goals. First, it was asked whether the policy had a specific funding mechanism that would set it apart from other measures to reduce energy use. Then, it was asked whether the sector addressed by the measure was covered under a more general goal. To address the issues of potential overlap, each option was examined relative to the option coverage by fuel, as summarized in the chart below. Then, each fuel type was addressed individually to assess potential overlap.

Table E-1. Impact of RCI-5

Option No.	Option Name	Electricity	Natural Gas	Fuel Oil	Propane	Biomass	Other Fuels
RCI-1	Maximize Savings From the Utility Conservation Improvement Program (CIP)	X					
RCI-2	Improved Uniform Statewide Building Codes	X	X				
RCI-3	Green Building Guidelines and Standards Based on the *Architecture 2030 Challenge*	X	X	X	X		X
RCI-4	Incentives and Resources To Promote CHP	X	X	X		X	X
RCI-5	Reduction of High GWP Emissions						
RCI-6	Non-Utility Strategies and Incentives	X	X	X		X	X
RCI-7	Conservation Improvement-Type Program for Propane and Fuel Oil Efficiency			X	X		
RCI-8	Energy Performance Disclosure	*Not quantified*					
RCI-9	Promote Technology-Specific Applications To Reduce GHG Emissions	*Not quantified*					
RCI-10	Appliance Standards	X	X				
	Coverage by Number of Options	6	5	4	2	2	3

Table E-2. Electricity

Option No.	Option Name	Electricity	Potential overlap with RCI-1?	Justification	Proposal for GHG reduction credit in integrated analysis
RCI-1	Maximize Savings From the Utility Conservation Improvement Program (CIP)	X	N/A	N/A	100%
RCI-2	Improved Uniform Statewide Building Codes	X	No	Savings would be incremental to the CIP	100%
RCI-3	Green Building Guidelines and Standards Based on the *Architecture 2030 Challenge*				
RCI-4	Incentives and Resources To Promote CHP	X	No	Savings would be incremental to the CIP	100%
RCI-5	Reduction of High GWP Emissions				
RCI-6	Non-Utility Strategies and Incentives	X	No	Savings would be incremental to the CIP	100%
RCI-7	Conservation Improvement-Type Program for Propane and Fuel Oil Efficiency				
RCI-8	Energy Performance Disclosure	*Not quantified*			

Option No.	Option Name	Electricity	Potential overlap with RCI-1?	Justification	Proposal for GHG reduction credit in integrated analysis
RCI-9	Promote Technology-Specific Applications To Reduce GHG Emissions	*Not quantified*			
RCI-10	Appliance Standards	X	Yes	High efficiency appliances a likely utility strategy to achieve CIP targets	50%

N/A = either not applicable or not analyzed.

Table E-3. Natural Gas

Option No.	Option Name	Natural gas	Potential overlap with RCI-3?	Justification	Proposal for GHG reduction credit in integrated analysis
RCI-1	Maximize Savings From the Utility Conservation Improvement Program (CIP)				
RCI-2	Improved Uniform Statewide Building Codes	X	N/A	Savings would be incremental to the “*Architecture 2030 Challenge*”	100%
RCI-3	Green Building Guidelines and Standards Based on the *Architecture 2030 Challenge*	X	N/A	N/A	100%
RCI-4	Incentives and Resources To Promote CHP	X	No	Savings would be incremental to the *Architecture 2030 Challenge*	100%
RCI-5	Reduction of High GWP Emissions				
RCI-6	Non-Utility Strategies and Incentives	X	No	Savings would be incremental to the *Architecture 2030 Challenge*	100%
RCI-7	Conservation Improvement-Type Program for Propane and Fuel Oil Efficiency				
RCI-8	Energy Performance Disclosure	*Not quantified*			
RCI-9	Promote Technology-Specific Applications To Reduce GHG Emissions	*Not quantified*			
RCI-10	Appliance Standards	X	Yes	Savings would be incremental to the *Architecture 2030 Challenge*	50%

N/A = either not applicable or not analyzed.

Table E-4. Fuel Oil

Option No.	Option Name	Fuel oil	Potential overlap with RCI-7?	Justification	Proposal for GHG reduction credit in integrated analysis
RCI-1	Maximize Savings From the Utility Conservation Improvement Program (CIP)				
RCI-2	Improved Uniform Statewide Building Codes				
RCI-3	Green Building Guidelines and Standards Based on the *Architecture 2030 Challenge*	X	No	Savings would be incremental to fuel oil/propane conservation	100%
RCI-4	Incentives and Resources To Promote CHP	X	No	Savings would be incremental to fuel oil/propane conservation	100%
RCI-5	Reduction of High GWP Emissions				
RCI-6	Non-Utility Strategies and Incentives	X	No	Savings would be incremental to fuel oil/propane conservation	100%
RCI-7	Conservation Improvement-Type Program for Propane and Fuel Oil Efficiency	X	N/A	N/A	100%
RCI-8	Energy Performance Disclosure	*Not quantified*			
RCI-9	Promote Technology-Specific Applications To Reduce GHG Emissions	*Not quantified*			
RCI-10	Appliance Standards				

N/A = either not applicable or not analyzed.

Table E-5. Propane

Option No.	Option Name	Propane	Potential overlap with RCI-7?	Justification	Proposal for GHG reduction credit in integrated analysis
RCI-1	Maximize Savings From the Utility Conservation Improvement Program (CIP)				
RCI-2	Improved Uniform Statewide Building Codes				
RCI-3	Green Building Guidelines and Standards Based on the *Architecture 2030 Challenge*	X	No	Savings would be incremental to fuel oil/propane conservation	100%
RCI-4	Incentives and Resources To Promote CHP				
RCI-5	Reduction of High GWP Emissions				
RCI-6	Non-Utility Strategies and Incentives				
RCI-7	Conservation Improvement-Type Program for Propane and Fuel Oil Efficiency	X	N/A	N/A	100%
RCI-8	Energy Performance Disclosure	*Not quantified*			
RCI-9	Promote Technology-Specific Applications To Reduce GHG Emissions	*Not quantified*			
RCI-10	Appliance Standards				

N/A = either not applicable or not analyzed.

Table E-6. Biomass

Option No.	Option Name	Biomass	Potential overlap with RCI-4?	Justification	Proposal for GHG reduction credit in integrated analysis
RCI-1	Maximize Savings From the Utility Conservation Improvement Program (CIP)				
RCI-2	Improved Uniform Statewide Building Codes				
RCI-3	Green Building Guidelines and Standards Based on the *Architecture 2030 Challenge*				
RCI-4	Incentives and Resources To Promote CHP	X	N/A	N/A	100%
RCI-5	Reduction of High GWP Emissions				
RCI-6	Non-Utility Strategies and Incentives	X	No	Savings would be incremental to CHP	100%
RCI-7	Conservation Improvement-Type Program for Propane and Fuel Oil Efficiency				
RCI-8	Energy Performance Disclosure	*Not quantified*			
RCI-9	Promote Technology-Specific Applications To Reduce GHG Emissions	*Not quantified*			
RCI-10	Appliance Standards				

N/A = either not applicable or not analyzed.

Table E-7. Other fuels

Option No.	Option Name	Other fuels	Potential overlap with RCI-3?	Justification	Proposal for GHG reduction credit in integrated analysis
RCI-1	Maximize Savings From the Utility Conservation Improvement Program (CIP)				
RCI-2	Improved Uniform Statewide Building Codes				
RCI-3	Green Building Guidelines and Standards Based on the *Architecture 2030 Challenge*	X	N/A	N/A	100%
RCI-4	Incentives and Resources To Promote CHP	X	No	Savings would be incremental to the *Architecture 2030 Challenge*	100%
RCI-5	Reduction of High GWP Emissions				
RCI-6	Non-Utility Strategies and Incentives	X	No	Savings would be incremental to the *Architecture 2030 Challenge*	100%
RCI-7	Conservation Improvement-Type Program for Propane and Fuel Oil Efficiency				
RCI-8	Energy Performance Disclosure	*Not quantified*			
RCI-9	Promote Technology-Specific Applications To Reduce GHG Emissions	*Not quantified*			
RCI-10	Appliance Standards				

N/A = either not applicable or not analyzed.

Interaction of RCI Policy Recommendations with Other Sectors

RCI and Energy Supply:

- The primary interaction between RCI and Energy Supply policies is that the RCI policies decrease overall electricity demand, thereby reducing the impact of RPS programs (ES-2), which are designed to serve a certain percentage of electricity sales from renewable sources. This reduction is accounted for in the ES sector adjustments
- The CHP option (RCI-4) was modeled in the energy supply analysis.

There are no significant overlaps between RCI and any of the other sectors.

ES Cumulative Impacts Analysis Methodology

The dominant policy recommendation for promoting renewable energy resource development is ES-5, mandated renewable energy standard (RES). There are two other renewable options, ES-3 (biomass co-firing at coal power stations) and ES-12 (distributed renewables). These were modeled as incremental to the RES. The remaining quantified option, ES-4 (transmission system upgrading) modeled the natural gas system, and was modeled as incremental to all ES options.

Interaction of Energy Supply Policy Recommendations with Other Sectors

ES and RCI:

- As indicated in the RCI sector cumulative impact analysis, the primary interaction between ES and RCI policies is that the RCI policies decrease overall electricity demand, thereby reducing the impact of the RES programs (ES-5) which are designed to serve a certain percentage of electricity sales from renewable sources. The GHG reductions and cost-effectiveness calculations are therefore included in the ES sector.

ES and AFW:

There are no overlaps between ES and the AFW sectors. All biomass used in co-firing is incremental to that used in the AFW sectors.

ES and TLU:

There are no overlaps between ES and the TLU sectors.

TLU Cumulative Impacts Analysis Methodology

CCS calculated the net cumulative impact of the TLU policy recommendations in order to account for overlap and interaction among policies. The GHG reductions resulting from individual stand-alone policies are not necessarily additive. For example, a policy that reduces VMT will reduce the GHG benefits of a policy that improves vehicle fuel economy or reduces fuel carbon intensity; a mile not driven removes the opportunity to reduce the carbon content of the fuel that would otherwise have been used to drive that mile.

A spreadsheet analysis was used to calculate net cumulative impacts. The first step in this analysis was to identify all the policies that affect VMT and determine the net VMT impact of this subset. The next step is to correct for overlaps between the policies. Table E-8 summarizes which recommended policies were analyzed as overlapping, and thus corrected, and which would be essentially additive, and therefore not corrected.

Table E-8. TLU Sector Overlaps

Policy No.	Policy Recommendation	Overlapping/ corrected	Stand-alone/ not corrected
TLU-1	Improved Land-Use Planning and Development Strategies	X	
TLU-2	Expand Transit, Bicycle, and Pedestrian Infrastructure	X	
TLU-5	Climate-Friendly Transportation Pricing/Pay-as-You- Drive	X	
TLU-7	"Fix-it-First" Transportation Investment Policy and Practice	X	
TLU-9	Workplace Tools To Encourage Carpooling, Bicycling, and Transit Ridership	X	
TLU-14	Freight Mode Shifts: Intermodal and Rail		X
TLU-3	Low-GHG Fuel Standard	X	
TLU-4	Infrastructure Management	X	
TLU-6	Adopt California Clean Car Standards	X	
TLU-12	Voluntary Fleet Emission Reductions		X
TLU-13	Reduce Maximum Speed Limits	X	

TLU-12 and -14 affect only heavy-duty vehicles and therefore have no overlap with other policies.

The net cumulative GHG reduction from the TLU policy recommendations (9.3 $MMtCO_2e$ in 2025) is 12.2% lower than the sum of the individual policy impacts.

Interaction of TLU Policy Recommendations with Other Sectors

TLU-3, the Low-GHG Fuel Standard, would likely overlap with AFW-3: In-State Liquid Biofuels Production: elements B (fossil diesel displacement) and C (gasoline displacement) have a direct overlap with the TLU low carbon fuels standard. The AFW recommendation focuses on in-state production, while the TLU policy focuses on biofuels consumption. CCS assumed 100% overlap in the benefits. So these were removed from the AFW sector level totals (after overlap adjustments) in the summary table of the Appendix.

Overlap Adjustments to TLU Sector:

Based on the assumptions above, the cumulative TLU total, adjusted for overlaps, would be as shown in Table E-9.

Table E-9. Overlap Adjustments to TLU Sector

TLU SECTOR	2015 GHG Reductions ($MMtCO_2e$)	2025 GHG Reductions ($MMtCO_2e$)	2008–2025 GHG Reductions ($MMtCO_2e$)	2008–2025 Costs (Savings) (Net Present Value Million $)	2008-2025 Cost-Effectiveness ($/t$CO_2e$)
Totals of Individual Policies without Adjustments for Overlaps	5.1	10.6	103.1	*Not Calculated*	
Totals Adjusted for Overlaps Among Policies	4.7	9.3	91.2	*Not Calculated*	

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent

* Totals from all 8 TLU recommendations with estimated GHG reductions.

† Totals from only those 4 TLU recommendations with estimated costs/cost savings.

AFW Cumulative Impacts Analysis Methodology

AFW-7&8

These waste management policy recommendations have a significant interaction with one another, such that they could be considered a single broad municipal solid waste management policy recommendation. AFW-7 is focused on reducing waste generation and managing waste using the most GHG-beneficial practices (enhanced recycling and composting). To the extent that AFW-7 is successfully implemented, it will reduced the amount of waste left over for management using the “end of life” waste management practices under AFW-8. GHG reductions and costs have been estimated for each of these policies assuming that the other would not have been adopted, and these are shown in the summary table of the AFW appendix. An additional “incremental analysis” was conducted and documented in the appendix under AFW-8 to address the overlap between these recommendations. For example, if AFW-7 is fully-implemented, there is no waste available for the organics and waste-to-energy element (WTE) of AFW-8. The stand-alone and overlap-adjusted results are shown in Table E-10.

Table E-10. Stand-Alone and Overlap Adjustments for AFW-7&8

AFW SECTOR Recommendation	2015 GHG Reductions (MMtCO$_2$e)	2025 GHG Reductions (MMtCO$_2$e)	2008-2025 GHG Reductions (MMtCO$_2$e)	2008–2025 Costs (Savings) (Net Present Value Million $)	2008-2025 Cost-Effectiveness ($/tCO$_2$e)
Stand-Alone Estimates					
AFW-7. Front-End Waste Management	**3.39**	**7.40**	**70**	**–$438**	**–$6**
A. Source Reduction	0.00	3.6	20	$59	$3
B. Recycling	3.10	3.4	45	–$512	–$11
C. Composting	0.29	0.41	4.9	$15	$3
AFW-8 End of Use Waste Management Practices	**0.96**	**2.19**	**20**	**$913**	**$46**
A. Landfilled Waste Methane	0.066	0.73	4.4	$5.7	$1
B. Organics & WTE	0.52	0.63	8.1	$650	$80
C. WTE Preprocessing	0.37	0.84	7.9	$257	$32
Overlap-Adjusted Estimates					
AFW-7. Front-End Waste Management	**3.39**	**7.40**	**70**	**–$438**	**–$6**
AFW-8 End of Use Waste Management Practices	**0.19**	**0.42**	**5.1**	**$120**	**$24**
A. Landfilled Waste Methane	0.023	0.25	1.5	$3.8	$3
B. Organics & WTE	0.00	0.00	0.00	Not applicable	Not applicable
C. WTE Preprocessing	0.17	0.17	3.6	$116	$32
Total AFW 7&8 Overlap-Adjusted Estimates					
AFW-7&8	**3.58**	**7.82**	**75**	**–$318**	**–$4**

MMtCO$_2$e = million metric tons carbon dioxide equivalent; WTE = waste to energy; negative numbers represent cost savings

Interaction of AFW Policy Recommendations with Other Sectors

AFW-3: In-State Liquid Biofuels Production: elements B (fossil diesel displacement) and C (gasoline displacement) have a direct overlap with the TLU low carbon fuels standard. The AFW recommendation focuses on in-state production, while the TLU policy focuses on biofuels consumption. CCS assumed 100% overlap in the benefits. So these were removed from the AFW sector level totals (after overlap adjustments) in the summary table of the Appendix. However, it should be recognized that there could be additional GHG benefits (and economic benefits) for producing these fuels in-state rather than from out of state sources (due to lower transportation-related emissions).

AFW-4: Expanded Use of Biomass Feedstocks for Electricity, Heat or Steam Production: This option overlaps with ES-5 (Renewable and/or Environmental Portfolio Standard). In consultation with the ES TWG, CCS determined that the amount of biomass required for the ES option would exceed that envisioned to be produced under AFW-4. Also, the cost analysis for ES-5 provides an assumed cost for biomass which would offset the biomass production costs under AFW-4.

Therefore, CCS assumed a 100% overlap in both the benefits and costs for this option with ES-5. This is reflected in the appendix summary table totals (after adjusting for overlaps).

Overlap Adjustments to AFW Sector

Based on the assumptions above, the cumulative AFW totals, adjusted for overlaps, are as shown in Table E-11.

Table E-11. Overlap Adjustments to AFW Sector

AFW SECTOR	2015 GHG Reductions ($MMtCO_2e$)	2025 GHG Reductions ($MMtCO_2e$)	2008-2025 GHG Reductions ($MMtCO_2e$)	2008–2025 Costs (Savings) (Net Present Value Million $)	2008-2025 Cost-Effectiveness ($\$/tCO_2e$)
Totals of Individual Policies without Adjustments for Overlaps	19.9	48.7	440	$2,785	$6
Totals Adjusted for Overlaps Among Policies	13.2	29.5	279	$1,890	$7

$MMtCO_2e$ = million metric tons carbon dioxide equivalent.

Appendix F
Residential, Commercial, and Industrial Sectors Policy Recommendations

Summary List of Policy Recommendations

Policy No.	Policy Recommendations	GHG Reductions ($MMtCO_2e$)			Net Present Value (Million $)	Cost-Effectiveness ($/tCO_2e$)	Level of Support
		2015	2025	Total (2008–2025)			
RCI-1	Maximize Savings From the Utility Conservation Improvement Program (CIP)*	*Quantified as a "Recent Action"*					Enacted
RCI-2	Improved Uniform Statewide Building Codes	0.004	0.005	0.077	–$44	–$576	Unanimous
RCI-3	Green Building Guidelines and Standards Based on *Architecture 2030*	0.62	0.94	11.1	–$296	–$27	Unanimous
RCI-4	Incentives and Resources To Promote Combined Heat and Power (CHP)	0.96	4.95	33.1	$125	$3.8	Unanimous
RCI-5	Program To Reduce Emissions of Non-Fuel, High-Global-Warming-Potential GHGs	0.02	0.05	0.5	–$2	–$5	Unanimous
RCI-6	Non-Utility Strategies and Incentives To Encourage Energy Efficiency and Reduce GHG Emissions	0.25	1.30	8.3	–$307	–$37	Unanimous
RCI-7	Conservation Improvement-Type Program for Propane and Fuel Oil Efficiency	0.05	0.05	0.7	–$21	–$28	Unanimous
RCI-8	Energy Performance Disclosure	*Not quantified*					Unanimous
RCI-9	Promote Technology-Specific Applications To Reduce GHG Emissions	*Not quantified*					Unanimous
RCI-10	Support Strong Federal Appliance Standards and Require High State Standards in the Absence of Federal Standards	0.8	1.4	15.3	–$1,895	–$124	Unanimous
	Sector Total After Adjusting for Overlaps (RCI, Non-Electricity)	**0.76**	**0.69**	**10.41**	**–$464**	**–$44.6**	
	Sector Total After Adjusting for Overlaps (Integrated RCI and ES for Electricity)	**1.56**	**7.34**	**51.06**	**–$1,098**	**–$21.5**	
	Reductions From Recent Actions	**6.50**	**15.50**	**$143.4**	**–$8,454**	**–$59.0**	
	New Commercial Building Code	**0.18**	**0.21**	**3.16**	**–$1.8**	**–$0.6**	
	Sustainability Guidelines (New State Buildings)	**0.22**	**0.46**	**4.72**	**–$1.7**	**–$0.4**	
	10% Savings in State Buildings	**0.09**	**0.11**	**1.75**	**–$0.9**	**–$0.5**	
	RCI-1: New CIP*	**6.01**	**14.72**	**133.8**	**–$8,449**	**–$63.2**	
	Sector Total Plus Recent Actions	**8.82**	**23.53**	**204.9**	**–$10,016**	**–$48.9**	

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

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

Only the results of recommendations included in the final tabulation of GHG reductions and costs are shown in this table. For discussion of any sensitivity analyses undertaken, please see the discussion in RCI Appendix F, Annex 1.

* The CIP considered here is based on the CIP requirements (i.e., 1.5% energy savings goal) included in the Next Generation Energy Act of 2007; therefore, the emission reductions and cost savings estimated are included under "recent actions."

RCI-1. Maximize Savings From the Utility Conservation Improvement Program (CIP)

Policy Description

Senate File 145 establishes an energy policy goal for Minnesota to achieve annual savings equal to 1.5% of annual retail energy sales of electricity and natural gas. At least 1% of these sales should come directly through energy conservation improvement programs and rate design. The additional 0.5% of savings can come indirectly through energy codes and appliance efficiency standards, programs designed to transform the market or change consumer behavior, energy savings resulting from efficiency improvements to the utility infrastructure and system, and other activities to promote energy efficiency and energy conservation. These savings are based on the average of the last 3 years of sales for the utility.

The Minnesota Climate Change Advisory Group (MCCAG) recommends that the Minnesota Department of Commerce (MnDOC) work closely with the affected utilities and other parties to develop strategies and programs to achieve the increased energy savings goals in the new law. Such strategies and programs should include:

- The state should develop and implement a policy of "decoupling," or separation of utility sales from revenues**.**
- Utilities should develop a standardized portfolio of energy efficiency programs and program rebates that are designed to (1) overcome market barriers, such as lack of consumer knowledge of products and costs, and (2) capture overall system efficiencies—not just equipment efficiencies. This might include finding ways to improve the efficiency of the operation of entire class of equipment or entire systems.
- Utilities should collaborate in joint efforts to achieve market transformation, to conduct market and product research, and to change consumer behavior. For example, the utilities should act to stimulate industry-wide efficiency changes and energy savings in products that consume electricity.
- MnDOC should develop a standardized method for evaluating the success of utility programs.
- The state should seek to remove disincentives or regulations that inhibit energy efficiency.

At its December meeting, the MCCAG asked the Residential, Commercial, and Industrial (RCI) Technical Work Group (TWG) to consider a level of electric and natural gas utility energy conservation higher than the 1.5% annual energy savings goal in the recently passed 2007 legislation. In addition, on November 15, 2007, at its Midwest Energy Summit, the Midwestern Governors Association (MGA) agreed upon a regional goal for energy efficiency savings as follows:

> "Meet at least 2 percent of regional annual retail sales of natural gas and electricity through energy efficiency improvements by 2015, and continue to achieve an additional 2 percent in efficiency improvements every year thereafter."

Achieving annual energy efficiency savings equal to 2% of annual retail energy sales of electricity and natural gas by 2015 in Minnesota is a desirable goal. However, the technical feasibility and cost-effectiveness of achieving an energy savings level higher than the current 1.5% Minnesota goal are uncertain for electric and natural gas utilities. Therefore, the MCCAG recommends that Minnesota immediately undertake a study of the technical feasibility and cost-effectiveness of achieving a 2% energy efficiency savings goal for electric and natural gas utilities by 2015, and adopt such a goal if the study provides assurance that the goal can be reasonably achieved. Such a study should be undertaken by an independent organization and should include input from relevant state agencies, electric and natural gas utilities, and other interested parties.

Policy Design

Goals: As noted above.

Timing: The MnDOC program will begin June 1, 2008, with the exception of Xcel. MnDOC will report back to the state legislature on Conservation Improvement Program (CIP) goals by 2010.

Parties Involved: The residential, commercial, and industrial sectors are covered by the program.

Other: Not applicable

Implementation Mechanisms

As noted above.

Related Policies/Programs in Place

Minnesota natural gas and electric utilities' existing CIP programs.

Type(s) of GHG Reductions

Reductions from avoided fossil-fuel electricity generation and natural gas consumption as a result of energy conservation programs.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources: The following sources were used in the analysis

- State of Minnesota, Office of the Legislative Auditor, *Energy Conservation Improvement Program: Evaluation Report Summary*, St. Paul, MN, January 2005, available at: http://www.auditor.leg.state.mn.us/PED/pedrep/0504a.pdf
- Spreadsheet attachment in an e-mail from Peter Ciborowski to Bill Dougherty of the Center for Climate Strategies (CCS), dated October 26, 2007.
- Minnesota legislation regarding the Conservation Improvement Program, 2007.

Quantification Methods: See Annex 1.

Key Assumptions: See Annex 2.

Key Uncertainties

Projected sales, program costs.

Additional Benefits and Costs

Reduced air pollution.

Feasibility Issues

As noted above.

Status of Group Approval

Complete.

Level of Group Support

Enacted. Note that the 1.5% energy savings goal is included in existing Minnesota law and, therefore, is considered an existing action. The MCCAG included this as a priority for analysis in order to estimate the emission reductions and costs associated with the 1.5% energy savings goal and to consider increasing the goal.

Barriers to Consensus

Not applicable.

RCI-2. Improved Uniform Statewide Building Codes

Policy Description

Building energy codes specify minimum energy efficiency requirements for new buildings or for existing buildings undergoing a renovation. Given the long lifetime of most buildings, amending state building codes to include minimum energy efficiency requirements and periodically updating energy efficiency codes will provide long-term greenhouse gas (GHG) emission reductions.

The Minnesota Department of Labor and Industry (DOLI) has the responsibility of promulgating the building code in Minnesota. Where possible, DOLI has approved the International Code Council's (ICC's) "I" family of codes. In July 2007, the 2006 International Residential Code (IRC) and the 2006 International Building Code were both adopted with Minnesota-specific amendments to address the Minnesota climate and building practices. Both were also adopted without their respective energy code chapters, as DOLI had been working for some time to amend Minnesota's existing energy code. DOLI decided some time ago that the 2006 IRC Chapter 11 (energy code chapter) would be adopted with Minnesota amendments.

Chapter 11 of the 2006 IRC is greatly simplified compared with past codes, and is expected to be widely accepted because of a U.S. Department of Energy (DOE)-initiated amendment. That amendment allows builders to comply using a simple "cookbook" compliance method, without needing to perform computer calculations of windows, walls, and other building component areas.

As a result of the high energy efficiency requirements required by code since 2000, Minnesota leads the nation in producing energy-efficient one- and two-family homes. Although the new residential code will not significantly increase the efficiency of one- and two-family residential buildings, its applicability will be broadened to include townhouses and, by doing so, will increase their energy efficiency.

The new Minnesota commercial energy code is based on the American Society of Heating, Refrigerating and Air-Conditioning Engineers standard ASHRAE 91.1-2004, with important state amendments. The percentage increase in energy efficiency is unknown at this time, but will be substantial if stakeholders understand its importance and install components correctly so that efficiencies are realized.

A policy to implement and enforce the commercial and residential energy codes statewide should be addressed legislatively. Following are some facts about the current energy code requirements:

- Approximately 85% of Minnesota's population lives in an area where the Minnesota State Building Code (including the energy code) has been adopted and enforced.
- Of Minnesota's 87 counties, 39 have adopted the Minnesota State Building Code.

- In accordance with state law, virtually all cities with populations of 2,500 and above are enforcing the Minnesota State Building Code, even if they are located in a county that is not enforcing the code.
- If a municipality or county chooses to enforce a building or energy code, it must be the Minnesota State Building Code. A municipality may not adopt a code that is more or less stringent than the Minnesota State Building Code.
- A statewide building code requirement would affect 48 sparsely populated counties, outside of any cities with populations of 2,500 and above, that have not adopted the Minnesota State Building Code.
- While the Minnesota State Building Code is not enforced statewide, homebuilders who are licensed by the state are required to build code-compliant homes, regardless of location.

Additional measures to support the requirement that the building code be implemented statewide would include:

- Consumer and realtor education about the importance of energy efficiency;
- Improved enforcement of existing energy and mechanical codes;
- Training for code officials on energy code compliance and its importance;
- Training for builders, remodelers, and mechanical contractors on energy code compliance; and
- Development of a clearinghouse for information on how to provide access to software tools to calculate the impacts of energy efficiency and solar technologies on building energy performance.

Policy Design

Goals: As noted above.

Timing: Recognizing that Minnesota will be implementing a new commercial and residential energy code in 2008, other strategies that should be considered include:

- Implementing the energy code statewide in 2009 for all non-agricultural buildings. (Currently, agricultural buildings are exempt from building and energy code compliance).
- Updating energy codes every 3 years that are at least as efficient as the most recently adopted version of ICC's energy codes.
  - Three-year cycles will allow Minnesota construction and renovation to keep consistent with the most recent ICC national code cycles and to keep the construction industry updated with new materials and methods that increase energy efficiency. The 3-year cycle will also allow policy makers to address unintended consequences to durability or structural integrity caused by well-intentioned code changes.
- Mandating education for each new energy code cycle for
  - Residential contractors seeking a Minnesota license,
  - Residential contractors renewing a Minnesota license,

  - All building code officials who perform energy efficiency or mechanical inspections, and
  - All architects registered in the State of Minnesota who approve building designs or renovations that affect energy use.
- Requiring all mechanical contractors in Minnesota to be licensed and requiring several hours of continuing education on energy and mechanical code requirements during every new code cycle. The number of hours for continuing education will be determined by the certifying agency/organization.
- Developing an educational program for the public and realtors through MnDOC's Energy Information Office, explaining Home Energy Rating System (HERS) scores for different types of housing.
  - Require all realtors to complete at least 1 hour of continuing education about HERS ratings in existing and new residential homes by 2011.

Parties Involved: Current Energy Code Rules under the Building Code were adopted on April 15, 2000, for one- and two-family residential buildings and July 20, 1999, for commercial and residential buildings other than one- and two-family buildings. DOLI predicts that the new energy codes will go into effect in late 2007, or if there is a public hearing, by mid-2008: Minnesota Rules Chapter 7670 and Minnesota Rules Chapter 7672 cover new construction and remodeling of one- and two-family homes. Builders can choose from one or the other, which has led to confusion in complying with and enforcing the codes.

- These codes will be replaced by the new Residential Energy Code, Minnesota Rules Chapter 1322.

Minnesota Rules Chapter 7674 covers multifamily new construction and remodeling buildings that are 3 stories or less.

- Townhome units with separate entryways that do not share common spaces (e.g., hallways, laundry rooms, or foyers) will be covered under the new Residential Energy Code, Minnesota Rules Chapter 1322.
- Multifamily buildings that do not meet the townhome requirements for Chapter 1322 will be covered under the new Commercial Energy Code, Minnesota Rules Chapter 1323.

Minnesota Rules Chapter 7676 covers all buildings, except low-rise residential.

- All commercial buildings that do not meet the townhome requirements for Chapter 1322 will be covered under the new Commercial Energy Code, Minnesota Rules Chapter 1323.

Minnesota Rules Chapter 7678 covers requirements for insulation manufacturers to register uniform testing of energy efficiency and equipment manufacturers to register equipment efficiencies with MnDOC. Chapter 7678 will be repealed, as all of these requirements will be embodied in standards to be adopted by reference in Chapter 1322 or 1323.

Agricultural buildings as defined in Minnesota Statutes, section 16B.60 and subdivision 5, are exempt from the Minnesota State Building Code.

Implementation Mechanisms

Mandating the code statewide requires a statute revision by the Minnesota legislature. DOLI has developed a *Minnesota State Building Code Adoption Guide* for local jurisdictions.[1] Code revisions should be implemented by DOLI using the rulemaking process, which allows for public input.

Related Policies/Programs in Place

Minnesota Rules Chapters 7670, 7672, 7674, 7676, and 7678. See http://www.mncodes.org/energy.htm

Type(s) of GHG Reductions

Reductions from avoided fossil-fuel combustion for electricity and space heating.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources: The following sources were used in the analysis.

- U.S. DOE, Energy Information Administration (EIA), Office of Energy Statistics, "Electric Sales, Revenue, and Average Price 2006," Average Retail Price for Bundled and Unbundled Consumers by Sector, Census Division, and State, 2005. Available at: http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html
- U.S. Census Bureau, "Annual Estimates of Housing Units for the United States and States: April 1, 2000 to July 1, 2005," HU-EST2005-0l, July 2007. (Annual data released at end of every July.) Available at: http://www.census.gov/popest/housing/HU-EST2005.html
- U.S Census Bureau, "New Privately Owned Housing Units, Authorized Unadjusted Units for Regions, Divisions, and States," July 2007. (Annual data released at end of every July.) Available at: http://www.census.gov/const/C40/Table2/t2yu200512.txt
- U.S. DOE, EIA, "Residential Energy Consumption Survey 2001: Consumption and Expenditure Data Tables," November 18, 2004. Available at: http://www.eia.doe.gov/emeu/recs/recs2001/detailcetbls.html
- Ratios of new residential/commercial floor space to total floor space, from EIA, "Table B1. Summary Table: Totals and Means of Floorspace, Number of Workers, and Hours of Operation, 1999." Available at: http://www.eia.doe.gov/emeu/cbecs/excel/b1.xls
- U.S. Department of Commerce (DOC), National Oceanic and Atmospheric Administration (NOAA), National Environmental Satellite, Data, and Information Service. Historical Climatology Series 5-2: Monthly State, Regional and National Cooling Degree-Days Weighted by Population (Includes Aerially Weighted Temperature and Precipitation). Asheville, NC: National Climatic Data Center. Available at: http://lwf.ncdc.noaa.gov/oa/documentlibrary/hcs/cdd.200501-200607.pdf

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[1] State of Minnesota, Department of Labor and Industry, Construction Codes and Licensing Division. Minnesota State Building Code Adoption Guide. St. Paul, MN, January 2006. See: http://www.doli.state.mn.us/pdf/bc_pr_code_adoption_guide_1_06update.pdf

- U.S. DOC, NOAA, National Environmental Satellite, Data, and Information Service. Historical Climatology Series 5-1: Monthly State, Regional and National Heating Degree-Days Weighted by Population (Includes Aerially Weighted Temperature and Precipitation). Asheville, NC: National Climatic Data Center. Available at: http://lwf.ncdc.noaa.gov/oa/documentlibrary/hcs/hdd.200507-200607.pdf
- Minnesota population projection, from Martha McMurry, *Minnesota Population Projections 2005–2035*, St. Paul, MN: Minnesota State Demographic Center, June 6, 2007. Available at: http://www.demography.state.mn.us/documents/MinnesotaPopulationProjections20052035.pdf
- Utility electricity sales in 2005, from U.S. DOE, EIA, Office of Energy Statistics, "Form EIA-826 Database Monthly Electric Utility Sales and Revenue Data (2005)." Available at: http://www.eia.doe.gov/cneaf/electricity/page/eia826.html
- Sectoral electricity consumption, from U.S. DOE, EIA, Office of Energy Statistics, "1990–2006 Revenue from Retail Sales of Electricity by State by Sector by Provider," EIA-861. Available at: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html (file sales_revenue.xls).
- Energy Efficiency Task Force Report to the Clean and Diversified Energy Advisory Committee of the Western Governors' Association, *The Potential for More Efficient Electricity Use in the Western United States*, Denver, CO: Western Governors' Association, January 2006. Available at: http://www.westgov.org/wga/initiatives/cdeac/Energy%20Efficiency-full.pdf

Quantification Methods: See Annex 1.

Key Assumptions: See Annex 2.

Key Uncertainties

Projected economic growth rate in counties not covered by the current codes.

Additional Benefits and Costs

Uniform standards; reduced air pollution.

Feasibility Issues

None.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

RCI-3. Green Building Guidelines and Standards Based on *Architecture 2030*

Policy Description

Minnesota 2030 is intended to encourage a transformation of the building industry in Minnesota. It would adapt to Minnesota the ever-increasing goals of a national initiative called *Architecture 2030,* including an ultimate goal for eliminating net carbon emissions from the use of buildings by 2030. Minnesota 2030 would be a performance standard that would complement—not conflict with—existing green building programs, such as the Leadership in Energy and Environmental Design Green Building Rating System™ (LEED) and Green Globes. Any green building approach can be used, as long as it meets the performance standards of Minnesota 2030.

Minnesota 2030 would develop standards and incentives to meet the unique needs of Minnesota. It would be an incentivized voluntary program for the private sector, but would be mandated for selected public-sector buildings. State and local government agencies, including school districts, would be required to adopt guidelines and standards for the reduction of carbon emissions for all buildings consistent with *Architecture 2030* targets.[2] New building standards would be required to make the following reductions in carbon emissions:

2010	60% reduction
2015	70% reduction
2020	80% reduction
2025	90% reduction
2030	100% reduction

All guidelines and standards for major renovations of existing buildings would require reductions in carbon emissions consistent with the *Architecture 2030* target of 50% reduction. A variance process would be provided when meeting criteria is inappropriate or financially infeasible.

Initially, Minnesota 2030 goals would be only be modestly more aggressive than current codes, but would be strengthened over time as long as they continue to be cost-effective. The overall initiative would include the following components: Design Assistance and Modeling, Utility Financial Incentives, State Incentives, Commissioning, Data Analysis and Continuous Improvement, Training and Capacity Building, State and Local Governments and Schools.

On an ongoing basis, buildings built to the new standards will be monitored to ensure that the required energy savings are cost-effective, and will remain cost-effective as the standards are strengthened.

Policy Design

Goals: As noted above.

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[2] Specific energy targets for each building type are shown at: http://www.architecture2030.org/2030_challenge/2030_Challenge_Targets.pdf. These would need to be converted into carbon emissions in a Minnesota context.

Timing: The program will be voluntary when the law passes in June 2008. The goal is to have program in place on January 1, 2010, at which time the mandatory requirements, incentives, and disincentives will apply.

Parties Involved: The mandatory program is for all public building owners (state, county, city, and school). Incentives and disincentives are for all private building owners (residential, commercial and industrial). Research organizations should support this effort.

Implementation Mechanisms

The program should be implemented as follows:

- Pass legislation mandating that all state and local government agencies, including school districts, meet *Architecture 2030* criteria for new and existing buildings. Provide funding mechanisms to assist state and local governments and school districts in meeting these criteria.
- Provide tax incentives, utility design assistance and incentive programs, financing incentives (such as “green mortgages”), or other inducements for construction of new and retrofit of existing residential and commercial buildings.
- Provide expedited code review for projects meeting certain energy and green building standards and benchmarks.
- Require designers (architects and engineers) to sign off on plans certifying that the “best available energy technology” was used in completion of design, or explain why it was not. Require building owners to certify they have been informed of energy efficiency technologies by their design team, and accept the current design as meeting their requirements.
- Utilize performance contracting/shared savings arrangements as appropriate.
- Establish a database of ongoing building performance tracking in all sectors (building on existing database models).
- Establish a clearinghouse that provides information and assistance on green building guidelines and standards, the best available technologies for certain applications, a database of ongoing building performance tracking in all sectors, and access to design assistance and software tools to calculate the impacts of energy efficiency and renewable energy strategies.
- Establish education and training programs for all key decision makers, building professionals, and other participants in implementing this policy, including design professionals, such as architects, engineers, interior designers, planners, and landscape architects; building owners; developers, contractors/builders, and building operators/facility managers; and the financing, real estate, and insurance communities.
- Clearly communicate the fact that reducing energy use does not always proportionally reduce emissions, and consider developing disincentives to technologies that do not reduce emissions.

- Mandate that state boards of licensing exams for building professionals cover knowledge of the improved building codes and building energy performance requirements reflected in various policy options.

Related Policies/Programs in Place

Guidelines that are either required or voluntary in Minnesota include Minnesota Sustainable Building Guidelines (B3), LEED, Green Globes, National Association of Home Builders Guidelines, GreenStar, Green Communities (Minnesota Housing Process), and ENERGY STAR.

Existing federal and state tax credits. An inventory of other current incentives in the state needs to be conducted.

The current legislative goals of 100 LEED or Green Globes and 1,000 ENERGY STAR Buildings in Minnesota.

Existing continuing education mechanisms for professional education and development of new models as needed.

Type(s) of GHG Reductions

Reductions from avoided fossil-fuel combustion for electricity and space heating.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources:

- Minnesota inventory provided by P. Ciborowski (Minnesota Pollution Control Agency) to R. Strait (CCS).
- U.S. DOE, Energy Information Administration (EIA), Office of Energy Statistics, "Electric Sales, Revenue, and Average Price 2006," Average Retail Price for Bundled and Unbundled Consumers by Sector, Census Division, and State, 2005. Available at: http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html
- U.S. Census Bureau, "Annual Estimates of Housing Units for the United States and States: April 1, 2000 to July 1, 2005," HU-EST2005-0l, July 2007. (Annual data released at end of every July.) Available at: http://www.census.gov/popest/housing/HU-EST2005.html
- U.S Census Bureau, "New Privately Owned Housing Units, Authorized Unadjusted Units for Regions, Divisions, and States," July 2007. (Annual data released at end of every July.) Available at: http://www.census.gov/const/C40/Table2/t2yu200512.txt
- U.S. DOE, EIA, "Residential Energy Consumption Survey 2001: Consumption and Expenditure Data Tables," November 18, 2004. Available at: http://www.eia.doe.gov/emeu/recs/recs2001/detailcetbls.html
- Ratios of new residential/commercial floor space to total floor space, from EIA, "Table B1. Summary Table: Totals and Means of Floorspace, Number of Workers, and Hours of Operation, 1999." Available at: http://www.eia.doe.gov/emeu/cbecs/excel/b1.xls

- U.S. Department of Commerce (DOC), National Oceanic and Atmospheric Administration (NOAA), National Environmental Satellite, Data, and Information Service. Historical Climatology Series 5-2: Monthly State, Regional and National Cooling Degree-Days Weighted by Population (Includes Aerially Weighted Temperature and Precipitation). Asheville, NC: National Climatic Data Center. Available at: http://lwf.ncdc.noaa.gov/oa/documentlibrary/hcs/cdd.200501-200607.pdf
- U.S. DOC, NOAA, National Environmental Satellite, Data, and Information Service. Historical Climatology Series 5-1: Monthly State, Regional and National Heating Degree-Days Weighted by Population (Includes Aerially Weighted Temperature and Precipitation). Asheville, NC: National Climatic Data Center. Available at: http://lwf.ncdc.noaa.gov/oa/documentlibrary/hcs/hdd.200507-200607.pdf
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- Utility electricity sales in 2005, from U.S. DOE, EIA, Office of Energy Statistics, "Form EIA-826 Database Monthly Electric Utility Sales and Revenue Data (2005)." Available at: http://www.eia.doe.gov/cneaf/electricity/page/eia826.html
- Sectoral electricity consumption, from U.S. DOE, EIA, Office of Energy Statistics, "1990–2006 Revenue from Retail Sales of Electricity by State by Sector by Provider," EIA-861. Available at: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html (file sales_revenue.xls).
- Energy Efficiency Task Force Report to the Clean and Diversified Energy Advisory Committee of the Western Governors' Association, *The Potential for More Efficient Electricity Use in the Western United States*, Denver, CO: Western Governors' Association, January 2006. Available at: http://www.westgov.org/wga/initiatives/cdeac/Energy%20Efficiency-full.pdf

Quantification Methods: See Annex 1.

Key Assumptions: See Annex 2.

Key Uncertainties

New privately owned housing units; projected energy consumption in buildings.

Additional Benefits and Costs

Reduced local air pollution.

Feasibility Issues

None.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

RCI-4 Incentives and Resources to Promote Combined Heat and Power (CHP)

Policy Description

Combined heat and power (CHP) systems reduce fossil fuel use and GHG emissions, both through the improved efficiency of the CHP systems, relative to separate heat and power technologies, and by avoiding transmission and distribution losses associated with moving power from central power stations that are located far from where the electricity is used. This policy includes

- Promotion of the use of natural gas-fired CHP systems.
- Promotion of the use of biomass-fired CHP systems.
- Creation or expansion of markets for, and incentives designed to promote implementation of, CHP units in capacities suitable for residential, commercial, and industrial users.
- Provision of tax benefits, attractive financing arrangements, utility rebates, and other incentives to promote CHP technologies.
- Removal of barriers to CHP development, such as utility rate structures (discounted electric rates that compete with CHP) and interconnection standards (should be designed to facilitate economical and efficient CHP connection to the grid).
- Full consideration of the economic and environmental benefits of CHP as a resource in each electric utility's Integrated Resource Plan.

Potential supporting measures for this policy include training and certification of installers and contractors, net metering and other pricing arrangements, establishment of clear and consistent interconnection standards, and creation and support of markets for biomass fuels.

Policy Design

Goals: Achieve 50% of the CHP technical potential in Minnesota.

Timing: Implement changes in regulation necessary to encourage technologies by 2010.

Parties Involved: Encouraging the development of CHP will require coordination and cooperation among a number of different parties, including regulators (Minnesota Utilities Commission, U.S. Environmental Protection Agency [EPA]); utilities; other state agencies; industry associations; equipment suppliers/vendors/installers, building professionals, engineers; and research and development (R&D) associations.

Other: Not applicable.

Implementation Mechanisms

The following are potential implementation mechanisms and supporting activities for this mitigation policy.

- Couple incentives to reduce first cost to a specific payback level with requirements for new buildings. For example tax credits, low- or no-interest loans, and similar financial incentives to could be provided to businesses, industries, and commercial firms that adopt CHP/distributed generation/renewables. This is especially important for small manufacturers, who could be provided access to micro-loans.
- Encourage CHP systems of 20 megawatts (MW) or smaller (or of equivalent mechanical power) by a rapid adoption and customer-friendly implementation of Federal Energy Regulatory Commission Order 2006 for Standardization of Small Generator Interconnection Agreements and Procedures.
- Qualify heat use from CHP systems for existing renewable and energy efficiency incentive and loan programs.
- Allow energy service companies to sell CHP and consumer-sited distributed generation output to third-party customers.
- Facilitate governmental and nonprofit organizations sales of renewable energy credits and tax credits to the marketplace.
- Provide support for switching to less carbon-intensive energy resources (coal and oil to natural gas or biomass, electricity to solar water heating or space/process heat).

Voluntary emission targets for industrial operations can include:

- Fund CHP/distributed generation-related/renewable energy R&D contracts with private firms, grants and contracts with universities, intramural R&D conducted at government laboratories, R&D contracts with private/public consortia.
- Provide patent protection, R&D tax credits, production subsidies or tax credits to firms bringing new CHP/distributed generation-related/renewable energy technologies to market, tax credits or rebates for new technology buyers, government procurement, and demonstration projects.
- Treat methane capture and use in CHP systems at sewage treatment plants as a specific focus.
- Consider integration of distributed generation options with regional demand response initiatives and recommendations.

Expanded use of CHP generation in Minnesota will need to be accompanied by reviews of related regulations, including:

- Review of net-metering policies—e.g., electricity consumers who install on-site CHP or distributed generation fueled with renewable or fossil fuels. This review could consider the impact of nitrogen oxides and power factor requirements on net metering and availability of information for small customers.
- Consideration of rate issues in Minnesota, including decoupling of utility revenues from sales and rate design, with a specific focus on the impacts of rate design on GHG emissions.

Related Policies/Programs in Place

Midwest CHP Applications Center.

Type(s) of GHG Reductions

Carbon dioxide equivalent (CO_2e) reductions from avoided electricity production and avoided on-site fuel combustion, less additional on-site CO_2e emissions from fuel used in CHP systems.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources:

- U.S. DOE, EIA, Office of Energy Statistics, "Electric Power Annual 2006—State Data Tables. 1990–2006 Net Generation by State by Type of Producer of Energy Source," EIA-906. Available at: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html
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Quantification Methods: See Annex 1. Note that the quantification of this policy recommendation was integrated with MCCAG Energy Sector analysis.

Key Assumptions: See Annex 2.

Key Uncertainties

Costs of new CHP units, integration into electric system, projected fuel prices, available markets for heat production, CHP potential in Minnesota.

Additional Benefits and Costs

Reduced local air pollution; lower transmission and distribution costs.

Feasibility Issues

Cost-effectiveness of CHP systems dependent on the price of natural gas; interconnection is an issue.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

RCI-5. Program to Reduce Emissions of Non-Fuel, High-Global-Warming-Potential GHGs

Policy Description

High-global-warming-potential (HGWP) GHGs are classes of chemicals that have a number of commercial and industrial uses. They include the chemical species hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).[3] This policy recommends that the Minnesota Pollution Control Agency (MPCA) undertake a rulemaking process to identify uses and emission sources of HGWP GHGs and to eliminate the use or escape of such gases where that can be done at a reasonable cost.

Some of the HGWP GHGs have a global warming effect of up to 23,000 times that of carbon dioxide (CO_2). For example, a pound of sulfur hexafluoride is equal to the global warming impact of 11 tons of CO_2. Often substitutes for these gases are available, and in many cases, the cost of reducing their use can be very low. Thus, an overall percentage reduction of GHGs (including CO_2) will be more cost-effective if this subject is effectively addressed at an early date.

The major sources of HGWP GHGs include

- Air conditioning (mobile),
- Refrigerants,
- Aerosols,
- Foam insulations,
- Electric power systems,
- Semiconductor manufacturing,
- Solvents,
- Fire extinguishers, and
- Aerosol products.

Perhaps the major expected increase in these gases will result as HFCs are increasingly being used to replace ozone-depleting chlorofluorocarbons and hydrochlorofluorocarbons in insulating foams, refrigeration and air-conditioning, fire suppression, solvent cleaning, and propellants used in aerosols and metered dose inhalers. In many cases, alternative substances or methods are available. Also the maintenance and disposal of equipment or building materials that contain

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[3] HGWP GHGs are among the gases reported by EPA pursuant to the Intergovernmental Panel on Climate Change, http://www.ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_Ch02.pdf. See Metz, B., O. Davidson, P. Bosch, R. Dave, and L. Meyer, eds, *Climate Change 2007: Mitigation of Climate Change*, Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, New York, NY: Cambridge University Press, 2007, available at: http://www.ipcc.ch/ipccreports/ar4-wg3.htm

these substances can be a large source of emissions. EPA’s Web site on this subject states: “EPA is actively working to reduce emissions of high GWP gases given their potency and long atmospheric lifetimes. Through a set of voluntary partnerships, EPA and industry are making substantial progress in reducing emissions by developing and implementing cost-effective improvements to industrial processes.”[4] EPA’s Web site also contains extensive information on the costs of control.

EPA has established voluntary partnerships in the electrical, aluminum, semiconductor, and magnesium industries. In addition, EPA has published a list of acceptable substitutes for ozone-depleting substances, which are controlled by the Montreal Protocol on Substances That Deplete the Ozone Layer.[5]

Policy Design

1. Elimination of emissions of HGWP GHGs at reasonable cost.

The MCCAG recommends that MPCA undertake a rulemaking process to identify uses and emission sources of HGWP GHGs and to eliminate the use of such gases where that can be done at a reasonable cost. For purposes solely of calculation of the costs and effects of this recommendation, a reasonable cost is determined to be $15 per ton CO_2 equivalent.

- The rulemaking process should include an initial scoping process to determine:
  - Which industries are the subject of an EPA voluntary partnership, or some other voluntary program, or EPA regulation resulting in reasonable measures to reduce emissions of HGWP GHGs; and
  - Which Minnesota industries and companies should be exempt from regulation because they have taken reasonable measures to reduce their emissions of HGWP GHGs;
- Individual companies not participating in such voluntary programs would not be exempt from regulation, nor would industries or companies where reductions of HGWP GHGs are possible at reasonable costs but are not being achieved.
- To the extent that tradable credits result from the rulemaking process for reductions in emissions, MPCA should develop a mechanism to provide such credits for companies that have reduced such emissions voluntarily.
- MPCA’s rulemaking process would:
  - Require the elimination of HGWP GHGs, on a phased basis, where this can be done at no cost;
  - Require the elimination or reduction of such gases by the use of prudent managerial practices, process changes, and improved technology or by substitution of other substances, or other means, where the cost of CO_2e reduction can be accomplished at a reasonable cost.

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[4] See http://www.epa.gov/highgwp/projections.html

[5] See http://www.epa.gov/ozone/snap/index.html. See also L. Kuijpers and R. Ybema, eds., *Proceedings of the Joint IPCC/TEAP Expert Meeting on Options for the Limitation of Emissions of HFCs and PFCs*, Energieonderzoek Centrum Nederland ECN-RX-99-029, Petten, Netherlands: Intergovernmental Panel on Climate Change and Technology and Economic Assessment Panel, July 15, 1999.

- ○ Establish the reasonable cost per ton of CO_2e reduction, taking into account the availability of alternatives.

2. **Promotion and funding for process optimization.**

   If HGWP GHGs can be eliminated at a reasonable cost, MPCA should mandate this through the rulemaking process (if it has not been done voluntarily through EPA programs or otherwise). In other cases, the state should provide funding and incentives for the reduction and phaseout of HGP GHGs, through tax incentives and funding for programs that offer education and technical assistance.

3. **Use of lower-impact alternatives for coolants, refrigerants, aerosols, solvents, and insulation.**

   Again, where substitutes can be used at a reasonable cost, that should be done pursuant to the rulemaking described above, if not voluntarily. Where substitutes are not available at reasonable costs, the state should undertake to reduce the use and emissions of HGWP GHGs through incentives and through the funding of programs that can provide technical assistance.[6]

Implementation Mechanisms

MPCA rulemaking process.

Legislative action to provide tax incentives and funding for technical support and assistance.

Technical support through the Minnesota Technical Assistance Program (MnTAP) or similar entities.

Related Policies/Programs in Place

MnTAP.

Type(s) of GHG Reductions

Reductions from avoided emissions of HGWP GHGs.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources:

- U.S. Environmental Protection Agency, Office of Air and Radiation, *U.S. High GWP Gas Emissions 1990–2010: Inventories, Projections, and Opportunities for Reductions*, EPA 000-F-97-000, June 2001. Available at: http://www.epa.gov/highgwp/projections.html
- Population projections from Martha McMurry, *Minnesota Population Projections 2005–2035*, St. Paul, MN: Minnesota State Demographic Center, June 6, 2007. Available at: http://www.demography.state.mn.us/documents/MinnesotaPopulationProjections20052035.pdf

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[6] EPA's Web site at http://www.epa.gov/ozone/snap/ has pertinent background information.

- U.S Census Bureau, “Interim Projections of the Total Population for the United States and States: April 1, 2000 to July 1, 2030.” Available at: http://www.census.gov/population/projections/SummaryTabA1.xls
- California Environmental Protection Agency, Air Resources Board, *Proposed Early Action to Mitigate Climate Change in California*, April 20, 2007. Available at: http://www.arb.ca.gov/cc/ccea/hfc-mac/documents/hfcdiy.pdf

Quantification Methods: See Annex 1.

Key Assumptions: See Annex 2.

Key Uncertainties

Costs of achieving reductions.

Additional Benefits and Costs

None.

Feasibility Issues

Feasibility issues should be examined as part of the rulemaking process.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

RCI-6. Non-Utility Strategies and Incentives To Encourage Energy Efficiency and Reduce GHG Emissions

Policy Description

This policy implements cost-effective non-utility strategies and incentives for industrial processes in manufacturing and commercial facilities that complement (but not duplicate) utility-based programs to reduce GHG emissions through energy efficiency and adoption of renewable energy technologies. These strategies include mechanisms to:

- Maximize convenience for program users and participants;
- Capture overall technology and system efficiencies;
- Conduct research, evaluation, and analysis of energy efficiency opportunities;
- Provide market, cost, and other incentives to implement;
- Remove disincentives and regulatory barriers;
- Partner with appropriate groups; and
- Provide technical assistance for implementation of energy-efficient technologies.

Implementation Mechanisms

The recommended implementation mechanisms fall into four categories: technical assistance for implementation of energy-efficient and renewable energy technologies, and direct reduction of GHGs from industry, tax incentives or benefits, and state economic assistance.

1. **Technical Assistance—**Voluntary, nonregulatory assistance for residential, commercial, and industrial entities as a mechanism to implement policies and expand related programs that would result in GHG reductions through energy efficiency savings and adoption of renewable energy technologies.

- Provide technical assistance to industrial and commercial facilities, including:
    - Site assessments and student intern projects for energy efficiency opportunities related to compressed air, steam systems, process heat, process refrigeration, pumps, fans, motors, etc.;
    - Energy-efficient technology demonstrations and pilot programs;
    - Resource development, including Web resources and best practices documents;
    - Workshops and seminars, including DOE best practices training;
    - Partnering with relevant industry associations and utilities; and
    - Evaluation of renewable energy technology options.
- Assist industries with implementation of the low-hanging fruit of energy savings through the above services. Four technology areas seem to be easy to implement with quick payback: process-related insulation, steam traps, lighting, and compressed air.

- Assist in the formation of process energy conservation teams within industrial facilities, or within an industry sector working with industry associations. The people in the plant have the most knowledge about their process, but they may get stalled on implementation. Energy conservation teams would be best suited initially for the quick hits that come from focusing on operation and maintenance activities. Over time these groups will provide the ideas for the larger capital projects.
- Assist facilities that run their own boilers to look at optimizing the operation of the steam system. Examples include right-sizing boilers, waste heat recovery from steam systems, boiler turndown, load balancing for buildings with multiple boilers, and improvements to boiler efficiency.
- Develop benchmarks for industrial and commercial operations where they don't exist or are not widely known, for industrial and commercial facilities or operations. The EPA ENERGY STAR program currently has three industries that have specific energy performance indicators that can be used to benchmark a facility to help prioritize where efforts should be focused: cement manufacturing, wet corn milling, and auto manufacturing. The energy performance indicator for a cement plant is based on the total amount of energy required to produce a short ton or 1 million British thermal units (MMBtu) per short ton of clinker. Focus groups could be formed to promote energy conservation in high-energy-use industries.
- Promote, develop information and resources, and provide assistance for the following industrial energy-efficient technologies that are not frequently used and also help reduce GHG emissions:
    - ○ Waste heat recovery (e.g., metal casting),
    - ○ Pumping systems (potential 20% savings),
    - ○ Combined heat and power (cogeneration), and
    - ○ Boiler blowdown heat exchangers or flash steam recovery systems.
- Have an outside party work with utilities and companies to track why energy-efficient and renewable energy technologies are not being implemented. This work would be "field proofing" ideas about barriers, such as getting industry feedback before beginning on a project. If this information already exists, it could be useful guidance on how to improve implementation.

2. Direct reduction of GHGs from industry (in addition to RCI-5 and others)

- Encourage the reduction of industrial emissions of GHGs (defined as climate change GHGs, including CO_2, methane (CH_4), nitrous oxide (N_2O), HFCs, PFCs, and SF_6) from industries that have the greatest volumes: food processing, ethanol, petroleum refining, and taconite mining. This could be achieved via voluntary initiatives, technical assistance, best practices checklists, policy (cap and trade), and/or regulatory and other incentives. Educate industries that these activities result in carbon offset credits that they can use as revenues.

3. Tax incentive programs (not already in place)

- Provide tax incentives for capital equipment that reduces energy use per unit of product by more than 10% (possibly on a sliding scale). Projects would be conducted in collaboration with the local utility. To protect public interest, applicants would adhere to the same measurement and verification protocols required by MnDOC of utility CIP custom energy efficiency projects of similar size. Equipment suppliers or businesses would need to measure energy consumption before and after installation of equipment.

- Offer tax incentives for specific technologies (i.e., pumps, motors, fans, boilers, compressed air systems) known to deliver energy efficiency. NEMA (National Electrical Manufacturers Association) Premium motors and adjustable speed drives in the right applications are possible technologies, but there are many others. The EPA and DOE Web sites list many ENERGY STAR products for commercial facilities (food, service, lighting, office equipment, etc) that could be given a tax incentive. This would be the simplest to administer because no verification (other then receipt for filing taxes) would be needed. Exempting qualifying items from sales tax would be even simpler to administer, such as is done for groceries. To protect public interest, applicants would use the same measurement and verification protocols required by MnDOC utility CIP prescriptive energy efficiency projects.

- Identify the large energy users and offer a tax incentive for energy reduction per ton of production. Discussions may be needed to determine what size credit might serve as an incentive. Large energy users are probably relatively efficient now, but still represent a substantial opportunity. A screening of energy intensity per ton of product may be needed to determine if variation in credit is warranted. Facility benchmarks might be available but not shared with the public. Pre- and post-testing would help ensure savings are achieved.

- Offer tax incentives for facilities that can move into the top 10% of a benchmark. Various building energy benchmarks (energy per square foot [ft^2]) exist for different sectors (schools, warehouses, churches, etc). For example, credit could be given for making it into the top 10% or 25%, or could be based on how far energy users moved toward conservation. An existing federal program grants a tax deduction of \$1.80 per ft^2 for buildings that reduce their energy consumption by 50% or more. If the reduction is at least 16.67%, then the tax deduction is \$0.60 per $ft.^2$ The program requires using DOE-approved software programs to calculate the energy savings.

- Provide tax incentives for reducing GHGs by adopting renewable energy technologies, such as biomass, biofuels, and biogas. Implementing renewable energy technologies offsets the use of fossil fuels, thus helping reduce GHG emissions.

4. State Economic Assistance

- Offer low- or no-interest loans or other economic assistance to companies and public entities that do audits, identify energy goals, are doing their first energy project, or are implementing energy-efficient technologies. The loans may require that an energy analysis be performed to calculate the energy savings that will be achieved, which will help ensure the loan will be paid off.

- Conduct a review of all Minnesota economic development assistance projects to ensure that they encourage or require state-of-the-art efficiency and environmental technologies (key to Minnesota’s industrial competitiveness).

- Promote and pilot test performance contracting in energy areas. Performance contracting is defined as a contract between a building owner and a contractor for the purpose of saving energy in the owner’s building. The contractor agrees to research, design, build, and maintain capital improvements that are expected to save energy and dollars. The owner agrees to pay the contractor from savings realized during the contract period.

Policy Design

Goals—program begins:

Tax benefits: 2010

Technical assistance: 2008–2009
State economic assistance: 2010
Direct reduction of GHGs from industry: 2010

Goals—goals achieved:

Tax benefits: 2012
Technical assistance: 2010
State economic assistance: 2012
Direct reduction of GHGs from industry: 2012

Parties Involved

Tax benefits: Residential customers, commercial establishments, and industrial facilities.

Technical assistance: Commercial establishments and industrial facilities.

State economic assistance: Residential customers, commercial establishments, and industrial facilities.

Direct reduction of GHGs from industry: Industrial facilities.

Type(s) of GHG Reductions

- Reductions from avoided fossil-fuel electricity generation as a result of implementation of energy-efficient practices and technologies.
- Reductions of industrial-based GHGs of CH_4 and N_2O.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources: The following sources were used in the analysis

- Kenneth Gillingham, Richard Newell, and Karen Palmer, *Retrospective Examination of Demand-Side Energy Efficiency Policies*, RFF DP 04-19 REV, Washington, DC: Resources for the Future, 2004; revised September 2004. Available at: http://www.rff.org/Documents/RFF-DP-04-19REV.pdf
- Minnesota inventory provided by P. Ciborowski (MPCA) to R. Strait (CCS).
- U.S. DOE, Energy Information Administration (EIA), Office of Energy Statistics, "Electric Sales, Revenue, and Average Price 2006," Average Retail Price for Bundled and Unbundled Consumers by Sector, Census Division, and State, 2005. Available at: http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html
- Average Retail Price for Bundled and Unbundled Consumers by Sector, Census Division, and State, 2005, available at: http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

- U.S. Census Bureau, "Annual Estimates of Housing Units for the United States and States: April 1, 2000 to July 1, 2005," HU-EST2005-0l, July 2007. (Annual data released at end of every July.) Available at: http://www.census.gov/popest/housing/HU-EST2005.html
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- U.S. DOE, EIA, "Residential Energy Consumption Survey 2001: Consumption and Expenditure Data Tables," November 18, 2004. Available at: http://www.eia.doe.gov/emeu/recs/recs2001/detailcetbls.html
- Ratios of new residential/commercial floor space to total floor space, from EIA, "Table B1. Summary Table: Totals and Means of Floorspace, Number of Workers, and Hours of Operation, 1999." Available at: http://www.eia.doe.gov/emeu/cbecs/excel/b1.xls
- U.S. Department of Commerce (DOC), National Oceanic and Atmospheric Administration (NOAA), National Environmental Satellite, Data, and Information Service. Historical Climatology Series 5-2: Monthly State, Regional and National Cooling Degree-Days Weighted by Population (Includes Aerially Weighted Temperature and Precipitation). Asheville, NC: National Climatic Data Center. Available at: http://lwf.ncdc.noaa.gov/oa/documentlibrary/hcs/cdd.200501-200607.pdf
- U.S. DOC, NOAA, National Environmental Satellite, Data, and Information Service. Historical Climatology Series 5-1: Monthly State, Regional and National Heating Degree-Days Weighted by Population (Includes Aerially Weighted Temperature and Precipitation). Asheville, NC: National Climatic Data Center. Available at: http://lwf.ncdc.noaa.gov/oa/documentlibrary/hcs/hdd.200507-200607.pdf
- Minnesota population projection, from Martha McMurry, *Minnesota Population Projections 2005–2035*, St. Paul, MN: Minnesota State Demographic Center, June 6, 2007. Available at: http://www.demography.state.mn.us/documents/MinnesotaPopulationProjections20052035.pdf
- Utility electricity sales in 2005, from U.S. DOE, EIA, Office of Energy Statistics, "Form EIA-826 Database Monthly Electric Utility Sales and Revenue Data (2005)." Available at: http://www.eia.doe.gov/cneaf/electricity/page/eia826.html
- Sectoral electricity consumption, from U.S. DOE, EIA, Office of Energy Statistics, "1990–2006 Revenue from Retail Sales of Electricity by State by Sector by Provider," EIA-861. Available at: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html (file sales_revenue.xls).
- Energy Efficiency Task Force Report to the Clean and Diversified Energy Advisory Committee of the Western Governors' Association, *The Potential for More Efficient Electricity Use in the Western United States*, Denver, CO: Western Governors' Association, January 2006. Available at: http://www.westgov.org/wga/initiatives/cdeac/Energy%20Efficiency-full.pdf

Quantification Methods: See Annex 1.

Key Assumptions: See Annex 2.

Related Policies and Programs in Place

Technical assistance: Build on the existing energy efficiency services of MnTAP (for manufacturers) and the Center for Energy and the Environment (for small businesses and commercial firms).

State economic assistance: MnDOC, State Energy Office grants; MPCA grants and loans.

Direct reduction of GHGs from industry: industry program initiatives and MnTAP.

Other Related Policies/Programs in Place

MnDOC Conservation Improvement Program (CIP).

The goals of utility conservation programs are to promote consumer and industry awareness of energy conservation and its positive effect on the environment, reduce utility bills for homes and businesses; generate innovations in developing energy-efficient products and technologies, and promote new energy resource development.

Next Generation Act of 2007: Minnesota's energy policy aims to achieve annual energy savings equal to 1.5% of annual retail energy sales of electricity and natural gas directly through energy conservation improvement programs and rate design, and indirectly through energy codes and appliance standards, programs designed to transform the market or change consumer behavior, energy savings resulting from efficiency improvements to the utility infrastructure and system, and other efforts to promote energy efficiency and energy conservation.

Section 1605b of the 1992 Energy Policy Act (Public Law 102-485) mandated the creation of a national inventory of GHGs and a national database of voluntary reductions in GHG emissions. In doing so, Section 1605b directed DOE to establish a procedure for voluntary annual reporting of GHG emissions and emission reductions by companies from the year 1987 forward.

DOE runs a suite of programs dedicated to improving the energy efficiency of buildings, including Building America, Rebuild America, the High Performance Buildings Initiative, and the Zero Energy Buildings Initiative. All of these programs work through the development of voluntary public-private partnerships.

DOE's Office of Industrial Technologies runs two programs primarily focused on industrial energy audits: Industrial Assessment Centers and Plant-wide Assessments.

The Partnership for Advanced Technology in Housing (PATH) program is a voluntary public-private partnership between homebuilders, product manufacturers, insurance companies, and financial companies and the U.S. Department of Housing and Urban Development. It is dedicated to improving residential housing's energy efficiency, affordability, durability, environmental sustainability, and resistance to natural disasters.

ENERGY STAR is an umbrella term encompassing a broad range of programs, all designed to encourage energy-efficient investments.

DOE's Weatherization Assistance Program (WAP) was authorized under Title IV of the Energy Conservation and Production Act (Public Law 94-385) in 1976 to fund weatherization measures for low-income households to reduce their energy use. WAP prioritizes services to low-income families with children, the elderly, people with disabilities, and low-income households with a high energy burden. The program works through partnerships between DOE and state and local agencies that are recipients of DOE program grants.

The Climate Challenge program is a voluntary partnership between electric utilities and DOE designed to facilitate voluntary GHG emission reductions by utilities.

Key Uncertainties

Cost-effectiveness of technical assistance visits.

Additional Benefits and Costs

Reduced local air pollution.

Feasibility Issues

Measuring the effectiveness or total energy savings from a conservation initiative or program can be problematic due to difficulties in defining the right baseline, failure to correct for free riding or the "rebound" effect, use of inappropriate discount rates, and double counting of the same energy savings attributed to multiple government programs. A major question that arises when measuring program costs or cost-effectiveness is whether all of the salient costs (costs to business, costs to consumers, including consumer surplus losses due to quality changes, and costs to the government) are being accounted for. Equally important, the benefits of the programs (including otherwise unaccounted-for spillovers) must be properly accounted for. All of these issues combined suggest that considerable care must be taken in interpreting existing estimates of the effectiveness and cost of energy efficiency programs.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

RCI-7. Conservation Improvement-Type Program for Propane and Fuel Oil Efficiency

Policy Description

This policy implements cost-effective programs to reduce propane and fuel-oil use; targets rebates to overcome market barriers; maximizes convenience to program participants; captures overall system efficiencies, not just equipment efficiencies; involves joint efforts to achieve market transformation; includes ongoing research, evaluation, and analysis; complements government, utility, and non-utility efficiency programs; and seeks to remove any disincentives or regulatory barriers to energy efficiency.

Policy Design

Goals:

- Establish minimum efficiency heating plant standards consistent with US DOE's ENERGY STAR program. Current ENERGY STAR efficiency standards are 80% for fuel oil and 85% for propane (including water heating). Recommend rebates for high-efficiency models starting at 85% for fuel oil and 90% for propane.
- Establish and implement a plan for inspection and tune-up of all existing in-use heating systems and establish an inspection cycle. This plan should include inspection of fuel storage and delivery systems. Inspections are to be conducted and certified by trained, certified personnel.
- Remove fuel rate disincentives and/or penalties for reduced energy consumption as a result of installing high-efficiency heating equipment.
- Provide low-interest loans for low-income households to encourage installation of higher-efficiency models.
- Encourage manufactures to take advantage of new technological developments, such as alarm systems for carbon monoxide leaks, etc., and for component failure (e.g., filter plug, restricted heat exchanger).
- Provide public recognition to individuals or companies that are successful leaders in promoting efficiency standards.

Timing: All goals must be initiated and progress evaluated by 2009.

Parties Involved: All interested parties.

Other: Not applicable.

Implementation Mechanisms

Create an ongoing state task force of consumers, state agencies, utilities, and business representatives to annually review CIP initiatives and make changes according to program effectiveness, technological changes, and critical fuel changes.

Related Policies/Programs in Place

Xcel's CIP.

Type(s) of GHG Reductions

Reductions from avoided propane and fuel oil combustion.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources:

- Minnesota inventory provided by P. Ciborowski (MPCA) to R. Strait (CCS).
- U.S. Census Bureau, "Annual Estimates of Housing Units for the United States and States: April 1, 2000 to July 1, 2005," HU-EST2005-0l, July 2007. (Annual data released at end of every July.) Available at: http://www.census.gov/popest/housing/HU-EST2005.html
- U.S Census Bureau, "New Privately Owned Housing Units, Authorized Unadjusted Units for Regions, Divisions, and States," July 2007. (Annual data released at end of every July.) Available at: http://www.census.gov/const/C40/Table2/t2yu200512.txt
- Ratios of new residential/commercial floor space to total floor space, from EIA, "Table B1. Summary Table: Totals and Means of Floorspace, Number of Workers, and Hours of Operation, 1999." Available at: http://www.eia.doe.gov/emeu/cbecs/excel/b1.xls
- Regional fuel prices for fuel oil and propane from U.S. DOE, EIA, Office of Energy Statistics, "Supplemental Tables to the Annual Energy Outlook 2007." Available at: http://www.eia.doe.gov/oiaf/aeo/supplement/
- U.S. DOE, EIA, Office of Energy Statistics, "Natural Gas Prices." Available at: http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SMN_a.htm

Quantification Methods: See Annex 1.

Key Assumptions: See Annex 2.

Key Uncertainties

Ramp up period for achieving efficiency improvement; projected fuel oil and propane fuel costs.

Additional Benefits and Costs

Reduced local air pollution.

Feasibility Issues

None.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

RCI-8. Energy Performance Disclosure

Policy Description

To engage utility consumers to actively take a role in Minnesota's energy future by considering efficiency and environmental impacts when using energy or purchasing energy-consuming appliances, the MCCAG recommends the following:

- Require utilities to provide an energy performance disclosure to parties owning any public, commercial, or residential property, preferably in an electronic format, and require property owners to make this information available to prospective buyers or renters to allow for energy efficiency and environmental impacts to be an integral part of the decision to buy or rent.
- Require utilities to provide property owners an energy consumption history to share with prospective purchasers or renters of the property, and require owners is obligated to provide the performance disclosure of their account for the term of their ownership, up to a maximum of the 12 most recent months. The energy consumption history should include additional information that would continue to encourage sound energy decisions, such as a rating factor based upon kBtu/ft^2/year (from the owner) and CO_2 emissions (from the utility company).
- Develop a task force of utilities and parties of concern to devise a uniform utility information standard that would provide relevant energy efficiency and environmental impact information to customers. For example, the standard might include information that indicates the incremental cost of energy per the quantity of billable units, a comparison with an average customer's energy use, the environmental impacts of such use, and fuel portfolios, if applicable. The purpose of this action is to quantify the consumer's energy use and to raise the level of interest.

Policy Design

Goals: In this case, the goal is the implementation of the program.

Timing: The program is voluntary form after law passes in mid-2008 and will become mandatory on January 1, 2010.

Parties Involved: All public and private building owners and utility companies would be covered by the program.

Implementation Mechanisms

Research is needed regarding the systems that need to be put in place for distributing information on commercial and residential buildings for sale or lease (e.g., the Multiple Listing System). It is also important to make sure the utilities are able to produce the information required. Eventually, more detailed information may be required to be disclosed.

Related Policies/Programs in Place

None.

Type(s) of GHG Reductions

Reductions from avoided fossil-fuel electricity generation and fuel combustion.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources: Not applicable.

Quantification Methods: This is a nonquantified option.

Key Assumptions: Not applicable.

Key Uncertainties

Timing; scope of disclosure.

Additional Benefits and Costs

Public awareness and education.

Feasibility Issues

The issue of the difference in performance based on the occupant's energy use. An example would be to measure on an occupant versus square foot basis or to average out a number of units.

The feasibility of the implementation of this option is focused on the fact that each utility bill is to include relevant energy efficiency and environmental impact information, such as the monthly incremental energy unit charge (less tax) and, for comparison, the historical charge for the same period from the previous billing year.

The feasibility of the implementation of this option is focused on the fact that new programs may be needed to engage and educate consumers regarding their incremental monthly billing charges and, as an outcome, to initiate sound knowledge-based energy decisions.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

RCI-9. Promote Technology-Specific Applications to Reduce GHG Emissions

Policy Description

Technology plays a critical role in the development of energy processes, including demand-side efficiency. Major progress in climate change policy requires improvements to technologies as well as increased rates of technology adoption and use. To achieve these ends, this policy option recommends the following actions:

- Use incentives to promote technology-specific applications that reduce GHG emissions.
- Identify the options through research, and organize them in categories, such as space heating, lighting, water heating, and plug loads.
- Include a process to determine and clarify which applications work best in reducing GHG emissions.
- Clearly communicate the fact that reducing energy use dose not always proportionally reduce emissions, and consider developing disincentives to technologies that do not reduce emissions.
- Emphasize producing on-site renewable energy as a technology-specific application.
- Clarify what is considered to be renewable energy (i.e., solar hot water heat, photovoltaics, and wind generation, as determined by current state law).
- Require 2% of energy used by state-funded buildings to be on-site renewable technology, and provide incentives to owners of other public and private buildings who produce at least 2% of their required building energy on site.

Policy Design

Goals: The goal is to have the program in place by 2010.

Timing: The program is voluntary form when law passes in June 2008, and the mandatory requirements and incentives apply once the program is in place on January 1, 2010.

Parties Involved: The program is mandatory for state-funded building owners. Incentives and disincentives are for all other public and private building owners (residential, commercial, and industrial). Research organizations should support this effort.

Other: Supplement with research of technology-specific applications for GHG reductions.

Implementation Mechanisms

Inform all building owners about the program, determine/fund possible private incentives, and coordinate with other programs’ education and training efforts.

Related Policies/Programs in Place

An inventory of all current incentives in Minnesota needs to be conducted (including an evaluation of the current cap on requiring utility companies to buy back renewable power at the cost of purchase).

Type(s) of GHG Reductions

Reductions from avoided fossil-fuel electricity generation and energy generation.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources: Not applicable.

Quantification Methods: This option is not quantified.

Key Assumptions: Not applicable.

Key Uncertainties

Timing of program; scope of coverage.

Additional Benefits and Costs

Promotes local innovation.

Feasibility Issues

Interaction with appliance standards and utility programs.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

RCI-10. Support Strong Federal Appliance Standards and Require High State Standards in the Absence of Federal Standards

Policy Description

Appliance efficiency standards reduce the market cost of energy efficiency improvements by incorporating technological advances into base appliance models, thereby, thereby creating economies of scale. This policy recommends that Minnesota adopt appliance efficiency standards not covered by federal standards or where higher-than-federal standard efficiency requirements are appropriate. California has established appliance efficiency standards for a number of appliances not currently included in national legislation, such as consumer electronics (standby power use) and general service incandescent lamps.

Specifically, this policy recommends that the state:

- Address existing federal appliance efficiency standards by developing a State of Minnesota Residential Appliance Efficiency Standard. (Consider adoption of the appliance efficiency standards adopted by California.). Request that the Governor, through the National Governors Association, provide the leadership to seek the federal government's adoption of the Minnesota Residential Appliance Efficiency Standard.
- As part of a Minnesota Residential Appliance Efficiency Standard, require that all energy-consuming appliances be labeled for average annual energy consumption (kilowatt-hours or thermal units). The information provided in the label would be in addition to any existing ENERGY STAR information that may already be provided for comparison purposes.
- Also as part of a Minnesota Residential Appliance Efficiency Standard, require the development of a consumer education program on appliance efficiency. Insist that all utilities and appliance retailers in the Minnesota provide appliance efficiency information to their customers.
- Require high-efficiency ENERGY STAR appliances to be installed in all new residential construction and major retrofits.
- Require utilities to provide ENERGY STAR appliance rebates where they are deemed cost-effective. (The MnDOC commissioner will determine cost-effectiveness in the CIP process.)
- Advocate for the adoption of a State of Minnesota Residential Appliance Upgrade Program.
- Where possible, require and/or encourage appliance manufacturers to adopt grid-friendly "smart chip" technology into their appliances that will allow utilities to communicate with "smart chip" appliances to curtail energy use and/or respond to energy pricing changes.

Policy Design

Goals: Increase the stringency of a set of appliance standards to the levels of those recommended by the report *Leading the Way: Continued Opportunities for New State Appliance and Equipment Efficiency Standards*.[7]

Timing: Adopt new standards by 2009.

Parties Involved: State agencies to enforce state codes and standards.

Other: Not applicable.

Implementation Mechanisms

Potential implementation mechanisms and supporting activities for this mitigation option include:

- Appliance standards promulgated by legislation or developed administratively;
- Assistance programs to help low-income consumers purchase appliances meeting more stringent standards, so as to reduce the higher-first-cost burden of higher-efficiency appliances on those consumers;
- Elevated energy standards for appliances and equipment purchased by public agencies; and
- Working with manufacturers and considering the impacts on manufacturers when setting new standards.

Related Policies/Programs in Place

The state is an ENERGY STAR Partner.

Type(s) of GHG Reductions

Reductions from avoided fossil-fuel electricity generation and natural gas consumption as a result of energy conservation programs.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources:

- Martha McMurry, *Minnesota Population Projections 2005–2035*, St. Paul, MN: Minnesota State Demographic Center, June 6, 2007. Available at: http://www.demography.state.mn.us/documents/MinnesotaPopulationProjections20052035.pdf
- U.S Census Bureau. “Interim Projections of the Total Population for the United States and States: April 1, 2000 to July 1, 2030.” Available at: http://www.census.gov/population/projections/SummaryTabA1.xls

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[7] S. Nadel, A. deLaski, M. Eldridge, and J. Kleisch, *Leading the Way: Continued Opportunities for New State Appliance and Equipment Efficiency Standards*, Washington, DC: American Council for an Energy-Efficient Economy, March 2006, available at: http://www.aceee.org/pubs/a062.htm

- Steven Nadel, Andrew deLaski, Maggie Eldridge, and Jim Kleisch, *Leading the Way: Continued Opportunities for New State Appliance and Equipment Efficiency Standards*, Washington, DC: American Council for an Energy-Efficient Economy, March 2006. Available at: http://www.aceee.org/pubs/a062.htm
- Energy Efficiency Task Force Report to the Clean and Diversified Energy Advisory Committee of the Western Governors' Association, *The Potential for More Efficient Electricity Use in the Western United States*, Denver, CO: Western Governors' Association, January 2006. Available at: http://www.westgov.org/wga/initiatives/cdeac/Energy%20Efficiency-full.pdf
- Minnesota inventory provided by P. Ciborowski (MPCA) to R. Strait (CCS).
- U.S. DOE, EIA, Office of Energy Statistics, "Supplemental Tables to the Annual Energy Outlook 2007." Available at: http://www.eia.doe.gov/oiaf/aeo/supplement/
- Minnesota natural gas prices from U.S. DOE, EIA, Office of Energy Statistics, "Natural Gas Prices." Available at: http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SMN_a.htm

Quantification Methods: See Annex 1.

Key Assumptions: See Annex 2.

Key Uncertainties

Scaling down of results of a national study to Minnesota conditions.

Additional Benefits and Costs

Reduced local air pollution.

Feasibility Issues

None.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

RCI Reductions from Recent Actions

RCI-Existing Action #1—Implementation of Existing Commercial Building Code

Building energy codes specify minimum energy efficiency requirements for new commercial buildings. Given the long lifetime of most buildings, amending state building codes to include minimum energy efficiency requirements and periodically updating energy efficiency codes will provide long-term GHG emission reductions.

The new Minnesota Commercial Energy code (http://www.doli.state.mn.us/buildingcodes.html) is based on the ASHRAE 91.1-2004 standard, with important state amendments. Though the percentage increase in energy efficiency is unknown at this time, it will be substantial if stakeholders understand its importance and install components correctly so that efficiencies are realized.

Because this energy code has been implemented recently, it is included in the evaluation of existing actions. However, the effects of the building code are not anticipated to take effect until 2009.

Policy Design

Goals:
Reduce energy use in new commercial buildings up to 50%, beginning in 2009.

Timing:
The policy currently exists. The Minnesota DOLI predicts that the new energy codes will go into effect in late 2007, or if there is a public hearing, by mid-2008.

Parties Involved: The following is a list of buildings or projects that are covered:

- Current Energy Code Rules under the State Building Code adopted on July 20, 1999, for commercial buildings.
- Minnesota Rules Chapter 7676 covers all buildings, except low-rise residential.
- All commercial buildings that do not meet the townhome requirements for Chapter 1322 will be covered under the new Commercial Energy Code, Chapter 1323.
- Agricultural buildings as defined in Minnesota Statutes, section 16B.60, and subdivision 5 are exempt from the Minnesota State Building Code.

Implementation Mechanisms

Mandating the code statewide requires a statute revision by the Minnesota Legislature. DOLI has developed a *Minnesota State Building Code Adoption Guide* for local jurisdictions available at: http://www.doli.state.mn.us/pdf/bc_pr_code_adoption_guide_1_06update.pdf

DOLI should implement code revisions using the rulemaking process, which allows for public input.

Related Policies/Programs in Place

Minnesota Rules Chapters 7670, 7672, 7674, 7676, and 7678 (http://www.mncodes.org/energy.htm

Type(s) of GHG Reductions

Reductions from avoided fossil-fuel combustion for electricity and space heating.

Estimated GHG Reductions

Data Sources: The following sources were used in the analysis:

- 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
- DOC-published cooling degree-days in Minnesota, available at: http://lwf.ncdc.noaa.gov/oa/documentlibrary/hcs/cdd.200501-200607.pdf
- DOC-published heating degree-days in Minnesota, available at: http://lwf.ncdc.noaa.gov/oa/documentlibrary/hcs/hdd.200507-200607.pdf
- Minnesota population projection, Minnesota State Demographic Center, available at: http://www.demography.state.mn.us/documents/MinnesotaPopulationProjections20052035.pdf
- Minnesota population projection in comparison to other Midwestern states, available at: http://www.census.gov/popest/datasets.html
- EIA-published utility electricity sales in 2005, available at: http://www.eia.doe.gov/cneaf/electricity/page/eia826.html
- EIA-published sectoral electricity consumption data, available at: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html (file sales_revenue.xls).
- 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, available at: http://www.westgov.org/wga/initiatives/cdeac/Energy%20Efficiency-full.pdf
- Estimate of building lifetime, Energy Information Administration/NEMS Model Documentation 2007: Commercial Sector Demand Module, Appendix A, available at: http://tonto.eia.doe.gov/FTPROOT/modeldoc/m066(2007).pdf
- Growth in commercial area floor space, from EIA, Supplemental Tables to the Annual Energy Outlook 2007. Table 22, Commercial Sector Energy Consumption, Floorspace, and Equipment Efficiency, available at: http://www.eia.doe.gov/oiaf/aeo/supplement/sup_rci.xls

Quantification Methods: See Appendix E.

Key Assumptions: The electricity and gas use reductions that result from more stringent building codes, relative to the Reference Case, are assumed to be 50% for the period 2009 to 2025. The square footage affected by this policy option is assumed to be 4% of available square footage in every year. The square footage affected is attributable to an annual 2% demolition/rebuild rate of existing square footage and 2% growth rate in total square footage within the state. The discount rate used is 5%.

Key Uncertainties

Extent of improvement estimated at between 30% and 50%; may be initially less than 50% and eventually more than 50%, depending on technologies available, cost, and effectiveness of operation and enforcement.

Replacement frequency of existing commercial buildings.

Growth of new commercial buildings.

Additional Benefits and Costs

Uniform standards, reduced air pollution, reduced electricity use, more comfortable buildings.

Feasibility Issues

This is an existing action, so it is feasible.

Status of Group Approval

Approved.

Level of Group Support

Not assessed, because it is an existing action.

Barriers to Consensus

None.

RCI-Existing Action #2—10% Reduction of Energy Use in State Buildings

Policy Description

The Departments of Administration and Commerce implemented the Saving Energy program in response to Governor Tim Pawlenty's Executive Order 05-16. The goal of the program is to reduce energy use by 10% in 2006 and pursue long-term energy conservation measures.

The results of the program for the first year are documented in the April 2, 2007, State Agency Energy Conservation Progress Report on the Governor's Executive Order 05-16 (available at: http://www.savingenergy.state.mn.us/files/2006_Report.pdf). This report, prepared by the Department of Administration, Plant Management Division, Energy Management Services, in cooperation with the Minnesota Department of Commerce, documents the energy reduction achieved throughout state facilities. Although some departments achieved a 14% savings, the overall savings achieved in the first year was 4.8%. The report stated that the state saved $1.25 million in energy costs.

Policy Design

Goals: 10% reduction in energy use in state buildings.

Timing: The program began in 2006 and is ongoing.

Parties Involved: This program is for all state buildings.

Implementation Mechanisms

The project was implemented through communications and operations activities. Communications consisted of setting up a Web site; holding seminars, presentations, and energy fairs; publishing an employee newsletter; and having other events for staff. Operations activities consisted of developing a Web-based energy consumption reporting system, implementing a pricing program to manage risk in state fuel procurement, identifying high-energy-use buildings, optimizing utility company rebates, and using third-party leases/purchases funding to replace old, inefficient equipment.

Related Policies/Programs in Place

Guidelines that are either required or voluntary in Minnesota include Minnesota Sustainable Building Guidelines (B3), LEED, Green Globes, National Association of Home Builders (NAHB) Guidelines, GreenStar, Green Communities (Minnesota Housing Process), and ENERGY STAR.

Existing federal and state tax credits. Need to inventory other current incentives in the state.

Current legislative goal of 100 LEED or Green Globes and 1,000 ENERGY STAR buildings in Minnesota.

Type(s) of GHG Reductions

Reductions from avoided fossil-fuel combustion for electricity and space heating.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources: The following sources were used in the analysis:

- Minnesota GHG forecast developed for this process available at: http://www.mnclimatechange.us/ewebeditpro/items/O3F16231.pdf
- Average Retail Price for Bundled and Unbundled Consumers by Sector, Census Division, and State, 2005, available at: http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html
- 2001 EIA Residential Energy Consumption Survey, available at: http://www.eia.doe.gov/emeu/recs/recs2001/detailcetbls.html#space
- DOC-published cooling degree-days in Minnesota, available at: http://lwf.ncdc.noaa.gov/oa/documentlibrary/hcs/cdd.200501-200607.pdf
- DOC-published heating degree-days in Minnesota, available at: http://lwf.ncdc.noaa.gov/oa/documentlibrary/hcs/hdd.200507-200607.pdf
- Minnesota population projection, Minnesota State Demographic Center, available at: http://www.demography.state.mn.us/documents/MinnesotaPopulationProjections20052035.pdf
- EIA-published utility electricity sales in 2005, available at: http://www.eia.doe.gov/cneaf/electricity/page/eia826.html
- Sectoral electricity consumption data, from EIA, available 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, available at: http://www.westgov.org/wga/initiatives/cdeac/Energy%20Efficiency-full.pdf
- Estimate of building lifetime, Energy Information Administration/NEMS Model Documentation 2007: Commercial Sector Demand Module, Appendix A, available at: http://tonto.eia.doe.gov/FTPROOT/modeldoc/m066(2007).pdf
- Growth in commercial area floor space, from EIA, Supplemental Tables to the Annual Energy Outlook 2007. Table 22, Commercial Sector Energy Consumption, Floorspace, and Equipment Efficiency, available at: http://www.eia.doe.gov/oiaf/aeo/supplement/sup_rci.xls

Quantification Methods: See Appendix E.

Key Assumptions: The electricity and gas use reductions that result from this policy option increase from 4% in 2006, to 8% in 2007, and 10% in 2008 through 2025. It is assumed that 10% of all commercial floorspace in Minnesota is government-owned and that commercial floorspace increases at the same rate as the national average growth rate (~2%). The discount rate used is 5%.

Key Uncertainties

Number and square footage of state buildings.

Additional Benefits and Costs

Reduced local air pollution.

Feasibility Issues

The executive order mandating thermostat setpoints could not be achieved in all facilities, due to concerns with humidity control.

Reporting compliance was not complete across all state agencies.

Status of Group Approval

Approved.

Level of Group Support

Existing policy; not applicable.

Barriers to Consensus

None.

RCI-Existing Action #3—Sustainability Program for State Buildings

Policy Description

The Minnesota Legislature established a goal of achieving 30% savings in existing public buildings in 2001. The Departments of Administration and Commerce refer to this initiative as "Buildings, Benchmarks and Beyond" or the B3 project. The Legislature required conservation benchmarking for all public buildings to identify and prioritize a decent list of poorly performing buildings. This applies to more than 10,000 buildings. The Legislature also required the creation of guidelines to make sure that the designs of new buildings are cost-effective and energy efficient.

The Departments of Administration and Commerce and their team of academics and consultants developed the State of Minnesota Sustainable Building Guidelines, version 2.0, issued in September of 2006 (http://www.msbg.umn.edu/). The guidelines set up a process that will eventually lead to a full accounting of the actual human, community, environmental, and life cycle economic costs and benefits of sustainable building design.

Sustainable design is a means to reduce energy expenditures; enhance the health, well-being, and productivity of the building occupants; and improve the quality of the natural environment. All of these can contribute to high-performance State buildings with lower life cycle costs. To move toward ensuring these outcomes, the guidelines attempt to quantify the human, community, environmental, and life cycle economic costs and benefits for each project.

Policy Design

Goals:

- Exceed existing energy code by at least 30% in state buildings.
- Encourage continual energy conservation improvements in new buildings.
- Ensure good indoor air quality.
- Create and maintain a healthy environment.
- Facilitate productivity improvements.
- Specify ways to reduce material costs.
- Consider the long-term operating costs of the building, including the use of renewable energy sources and distributed electric energy generation that uses a renewable source of natural gas or a fuel that is as clean or cleaner than natural gas.

Timing: The program began in 2003 and is ongoing.

Parties Involved: This program is for all state buildings.

Implementation Mechanisms

All new buildings funded in whole or part by Minnesota bond monies after January 15, 2004, must comply with the guidelines.

Related Policies/Programs in Place

Governor Tim Pawlenty's Executive Order 05-16 to reduce energy use in state buildings by 10%.

Guidelines that are either required or voluntary in Minnesota include LEED, Green Globes, NAHB Guidelines, GreenStar, Green Communities (Minnesota Housing Process), and ENERGY STAR.

Existing federal and state tax credits. Need to inventory other current incentives in the state.

Current legislative goal of 100 LEED or Green Globes and 1,000 ENERGY STAR buildings in Minnesota.

Type(s) of GHG Reductions

Reductions from avoided fossil-fuel combustion for electricity and space heating.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources: The following sources were used in the analysis:

- Minnesota GHG forecast developed for this process available at: http://www.mnclimatechange.us/ewebeditpro/items/O3F16231.pdf
- Average Retail Price for Bundled and Unbundled Consumers by Sector, Census Division, and State, 2005, available at: http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html
- 2001 EIA Residential Energy Consumption Survey, available at: http://www.eia.doe.gov/emeu/recs/recs2001/detailcetbls.html#space
- DOC-published cooling degree-days in Minnesota, available at: http://lwf.ncdc.noaa.gov/oa/documentlibrary/hcs/cdd.200501-200607.pdf
- DOC-published heating degree-days in Minnesota, available at: http://lwf.ncdc.noaa.gov/oa/documentlibrary/hcs/hdd.200507-200607.pdf
- Minnesota population projection, Minnesota State Demographic Center, available at: http://www.demography.state.mn.us/documents/MinnesotaPopulationProjections20052035.pdf
- EIA-published utility electricity sales in 2005, available at: http://www.eia.doe.gov/cneaf/electricity/page/eia826.html
- Sectoral electricity consumption data, from EIA, available 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, available at: http://www.westgov.org/wga/initiatives/cdeac/Energy%20Efficiency-full.pdf

- Estimate of building lifetime, Energy Information Administration/NEMS Model Documentation 2007: Commercial Sector Demand Module, Appendix A, available at http://tonto.eia.doe.gov/FTPROOT/modeldoc/m066(2007).pdf
- Growth in commercial area floor space, from EIA, Supplemental Tables to the Annual Energy Outlook 2007. Table 22, Commercial Sector Energy Consumption, Floorspace, and Equipment Efficiency, available at http://www.eia.doe.gov/oiaf/aeo/supplement/sup_rci.xls

Quantification Methods: See Appendix E.

Key Assumptions: The electricity and gas use reductions that result from this policy option increase from 4% in 2006, to 8% in 2007, and 3% annually thereafter, to a maximum reduction of 30% in 2018. It is assumed that 10% of all commercial floorspace in Minnesota is government-owned and that commercial floorspace increases at the same rate as the national average growth rate (~2%). The discount rate used is 5%.

Key Uncertainties

Number and square footage of state buildings.

Rate of achievement of energy efficiency goals.

Additional Benefits and Costs

Reduced local air pollution, good indoor air quality, reduction in material costs, improved productivity.

Feasibility Issues

This is an ongoing project. The guidelines have been published initially and in a revised version to minimize feasibility issues.

Status of Group Approval

Approved.

Level of Group Support

Existing policy; not applicable.

Barriers to Consensus

None.

Annex 1. Methodology for the Quantification of RCI Mitigation Options

This annex outlines key elements of the methodology used for quantifying the GHG impacts and costs for the RCI policy recommendations considered to be amenable to quantification. The list of topics addressed in this memo is summarized below.

A. Premises
B. Outputs
C. Methodology
D. Assumptions
E. Cost Inclusion

A. Premises

The analysis was based on the following key premises:

- *CCS role*—Unless a member of the RCI TWG offered to undertake an analysis of any of the options, it was assumed that CCS would undertake the analysis of the RCI options. Where an RCI TWG member offered to undertake the analysis of one or more options, CCS provided analytical support (e.g., review and technical feedback) as needed.
- *Transparency*—Data sources, methods, key assumptions, and key uncertainties are clearly indicated.
- *Analytical approach*—CCS adopted the general approach of cost-effectiveness (and NPV) analysis, as widely applied to GHG mitigation policy options,[8] and included direct, economic costs from the perspective of the state as whole (i.e., avoided costs of electricity, rather than consumer electricity prices).
- *Bottom-up analysis*— CCS adopted a bottom-up approach that is amenable to transparency and is capable of reflecting the costs (and cost savings) associated with individual policy options, in contrast to macroeconomic analysis, which aims to capture flows and interactions across all sectors of the economy. Potential macroeconomic impacts, cost, or benefits that fall disproportionately on specific groups or actors, as well external costs and benefits, were noted qualitatively where studies or other information were available.

B. Outputs

The analysis of mitigation options was organized to produce the following results:

- *Net GHG reduction potential* in million metric tons of carbon dioxide equivalent (MMtCO$_2$e), using the Intergovernmental Panel on Climate Change's 100-year global warming potential, reported annually for 2015, 2020, and 2025, as cumulatively for the

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[8] For more discussion of various economic analysis approaches, see, for example, Section 2.4 of B. Metz, O. Davidson, P. Bosch, R. Dave, and L. Meyer, eds., *Climate Change 2007: Mitigation of Climate Change*, Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, New York, NY: Cambridge University Press, 2007, available at: http://www.mnp.nl/ipcc/pages_media/AR4-chapters.html

period 2008–2025. Where significant additional GHG reductions or costs occur beyond the project period as a direct result of actions taken during the project period, these were indicated as appropriate.

- *Net present value cost* (or cost savings) for 2008–2025 in 2006 constant dollars, using a 5% real discount rate.[9] Positive numbers represent options with net costs; negative numbers represent options with net cost savings.
- *Cost per* $MtCO_2e$ emissions reduced (or removed) in units of dollars per metric ton of carbon dioxide equivalent ($\$/tCO_2e$). This figure represents the NPV cost divided by the cumulative emission reductions, both over the 2008–2025 period.

C. Methodology

As much as possible, the analysis used simple spreadsheet modeling techniques in which assumptions were transparent and readily accessible to any TWG member for review and adjustment. To ensure consistent results across options, common factors and assumptions were used for such items as:

- *Electricity avoided costs and emissions*—Common values ($/MWh and tCO_2/MWh) were developed based on available studies. Once a complete set of options was identified, each option was first be analyzed individually, and then addressed as part of an overall integrated analysis.
- *Fuel costs and projected escalation*—Fuel cost estimates were based on common sources wherever possible. For example, fossil fuel price escalation was indexed to DOE projections, as indicated in its most recent *Annual Energy Outlook.*[10]
- *Overlap with other TWGs*—Some RCI recommendations may overlap with Energy Supply (ES) TWG recommendations. The analysis for these recommendations was closely coordinated with the assumptions and other inputs used in the ES TWG recommendations.
- *Full-fuel-cycle approach*—Related to the previous point, a fuel cycle analysis was applied wherever emission impacts upstream (e.g., production, extraction) or downstream (e.g., waste disposal) from a specific activity constituted a significant fraction of a policy recommendation's emission impacts *and* studies were sufficient to enable estimation.

D. Assumptions

As much as possible, the analysis relied on data sources that are Minnesota-specific, and that TWG members were in a good position to obtain and provide. The success of this approach depended on how accessible the information was to TWG members and the timeliness with which it could be provided to the CCS analytical team. Where Minnesota-specific information could not be readily obtained, the analysis relied on published data from the DOE, DOE national laboratories, and other state climate change processes.

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[9] To avoid "end effects," capital investments with lifetimes longer than 2025 were represented in terms of levelized or amortized costs.

[10] U.S. DOE, EIA, *Annual Energy Outlook 2007: With Projections to 2030,* IDOE/EIA-0383(2007), February 2006. Available at: http://tonto.eia.doe.gov/ftproot/forecasting/0383(2007).pdf

E. Cost Inclusion

Several types of costs were explicitly considered in and excluded from the analysis, as summarized below.

- Costs included:
    - Capital costs levelized (amortized) where appropriate (e.g., for new energy-efficient equipment);
    - Operations and maintenance and other labor costs (or incremental costs relative to standard practice);
    - Fuel and material costs (e.g., for natural gas, electricity, biomass resources, water, fertilizer, material use, and electricity transmission and distribution); and
    - Other direct costs, administrative costs, and other costs (where readily estimated).
- Costs excluded*:*
    - External costs, such as the monetized environmental or social benefits/impacts (e.g., value of damage by air pollutants on structures and crops), quality-of-life improvements, improved road safety, or other health impacts and benefits;
    - Energy security benefits; and
    - Macroeconomic impacts related to the impacts of reduced or increased consumer spending and shifting of cost and benefits among actors in the economy.

Annex 2. Key Assumptions

RCI-1. Maximize Savings From the Utility Conservation Improvement Program (CIP)

Assumed start year for the new CIP legislation

2008

Total anual level of savings in electricity sales associated with new CIP legislation (%/yr)

1.5%	source: MN legislation; see 216B.241 ENERGY CONSERVATION IMPROVEMENT

Current estimates of accumulated embedded energy efficiency and conservation in 2003 based on the previous CIP legislation (i.e., savings from previous CIP activities as a percentage of total sales):

2

1	0.8%	source: Office of the Legislative Auditor, State of Minnesota, 2005, "Evaluation Report: Energy Conservation Improvement Program", January, page 5
2	0.5%	source: RCI TWG estimate as proposed during the TWG meeting held on 23 October 2007 **(default)**
3	0.4%	source: spreadsheet attachment in an email from Peter Ciborowski to Bill Dougherty dated 26 October 2007

2003 expenditures in MN for demand side electricity savings associated with the previus CIP statute

$52	2003 expenditures by regulated utilities (million $)
325	2003 savings from utility expenditures (GWh)

Financial parameters

2.5%	projected inflation rate (2003-2005)
5%	real discount rate (%)
10	Levelization period (years)

Marginal resource associated with electricity savings

1

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

Starting 2005 assumption for the full levelized cost--program costs, utility costs, and participant cost--of electric energy efficiency improvements

1

1	Value is	30	2005$/MWh
2	Value is user-defined		

Adjustment in 2005 assumption for the full levelized cost--program costs, utility costs, and participant cost--of electric energy efficiency improvements to account for aggressiveness of new MN CIP

1

1	Value increases by 1%/year, or by	18%	on average over the planning period
2	User-defined		

Final 2005 assumption for the full levelized cost--program costs, utility costs, and participant cost--of electric energy efficiency improvements

35.5 2005$/MWh

Estimated avoided costs, including the RES

156.5 2005$/MWh

RCI-2. Improved Uniform Statewide Building Codes

Assumed start year for the new CIP legislation

2009

Assumption for improvement of the residential building code relative to the current residential building code in areas where the building code HAS BEEN adotpted and IS BEING enforced

1

1	no improvement in energy efficiency (default)
2	User-defined

Assumption for improvement of the residential building code relative to the current residential building code in areas where the building code has NOT been adotpted

1

1	improvement in energy efficiency of	3%	(default)
2	User-defined		

Assumption for percent of the state population covered by current residential building codes

1

1	The percent of MN's population is	85%	covered by the current building code (default)
2	User-defined		

Assumption for future enforcement of the residential building code

1

1	100% Statewide (default)
2	User-defined

Assumption for improvement of the commercial building code relative to the current commercial building code in areas where the building code HAS BEEN adotpted and IS BEING enforced

1

1	no improvement in energy efficiency (default)
2	User-defined

Assumption for improvement of the commercial building code relative to the current commercial building code in areas where the building code has NOT been adotpted

1

1	improvement in energy efficiency of	5%	(default)
2	User-defined		

Assumption for percent of the state commercial activity covered by current commercial building codes

1

1	Percent of MN's commercial sector,	85%	is covered by the current building code (default)
2	User-defined		

Assumption for future enforcement of the commercial building code

1

1	100% Statewide (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	

RCI-3. Green Building Guidelines and Standards Based on *Architecture 2030*

Assumed CO2 reduction targets to meet the Architecture 2030 Challenge (% relative to Reference Case)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
0%	0%	0%	0%	0%	60%	62%	64%	66%	68%	70%	72%	74%	76%	78%	80%	82%	84%	86%	88%	90%

Percentage of new buildings subject to the new guidelines

	1			
1	Use	80%		
2	User-defined		*80%*	*since not user-defined, ignore value in cell at left*

Annual percentage of the existing building stock subject to renovation

	1			
1	Use	5%		
2	User-defined		*10%*	*since not user-defined, ignore value in cell at left*

Percentage of annual rennovated building stock subject to the new guidelines

	1			
1	Use	50%		
2	User-defined		*50%*	*since not user-defined, ignore value in cell at left*

Real discount rate

	1			
1	Use	5%		
2	User-defined		*4%*	*since not user-defined, ignore value in cell at left*

Payback period for efficient equipment (years)

	1			
1	Use	14		
2	User-defined		*10*	*since not user-defined, ignore value in cell at left*

Lifespan for efficient equipment (years)

	1			
1	Use	30		
2	User-defined		*30*	*since not user-defined, ignore value in cell at left*

RCI-4. Incentives and Resources To Promote Combined Heat and Power (CHP)

Assumed start year for the new CHP facilities

2013

Assumption for CHP potential in MN based on most recent available estimates

1

1	Maximum of:	2,100	MW (default)
2	Minimum of:	1,600	MW (default)
3	User-defined		

Assumption for percentage of installed CHP by 2025

1

1	Up to specified potential (defaul)
2	User-defined

Marginal resource associated with electricity savings

1

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

Combined heat and power (CHP) cost and performance

	2010					2025				
Parameter	NG	Biomass	Coal	electricity	oil	NG	Biomass	Coal	electricity	oil
Average full-capacity-equivalent hours of operation	5,000	5,000	5,000			5,000	5,000	5,000		
Fraction of new capacity	90%	5%	5%			83%	18%	0%		
Average net heat rate by fuel (btu per kWh)	10,000	13,000	12,000			10,000	13,000	12,000		
Useable cogenerated heat output (% energy input)	40%	40%	40%			40%	40%	40%		
Fraction useable heat output replacing space/water/process heat	90%	90%	90%			90%	90%	90%		
Fraction of CHP heat output displacing thermal energy	75%	5%	0%	15%	5%	75%	5%	0%	15%	5%
Net efficiency of displaced boiler/heater thermal energy	85%	80%	80%	92%	80%	85%	80%	80%	92%	80%
Average overnight installed captial costs by fuel type (2005$/kW)	$2,000	$2,500	$2,500			$2,000	$2,500	$2,500		
CHP transmission cost (2005$/kW)	$0	$0	$0			$0	$0	$0		
Economic life of system (years)	20	20	20			20	20	20		
Fixed O&M costs (2005$/kW)	0	0	0			0	0	0		
Variable O&M costs (2005 $/MWh)	16.00	20.00	20.00			16.00	20.00	20.00		

RCI-5. Program To Reduce Emissions of Non-Fuel, High-Global-Warming-Potential GHGs

GENERAL ASSUMPTIONS

Assumed start year for the option

2009

Implementation ramp-up schedule

1

1	Linearly up to maximum by 2025 (default)
2	User-defined ramp-up period

Real discount rate

5%

Cost effectiveness threshold (2005$/tCO2e avlided)

$15.0

Inflation rate

1

1	Use	2.50%
2	User-defined	

Global warming potential

HFC-134a	1,300
SF-6	23,900

SF6 - ELECTRIC TRANSMISSION

Mitigation cost (recycling) (2005$/tCO2e)

1

1	EPA assumption (default)	-9.31
2	User-defined	

Maximum mitigation reduction potential (recycling)

1

1	EPA assumption (default)	10%
2	User-defined	

Mitigation cost (leak detection) (2005$/tCO2e)

1

1	EPA assumption (default)	6.56
2	User-defined	

Maximum mitigation reduction potential (leak detection)

1

1	EPA assumption (default)	20%
2	User-defined	

HFC and PFC - SEMICONDUCTORS

HFC and PFC mitigation cost (NF3 remote clean technology) (2005$/tCO2e)

	1	
1	EPA assumption (default)	5.20
2	User-defined	

HFC and PFC maximum mitigation reduction potential (NF3 remote clean technology)

	1	
1	EPA assumption (default)	9%
2	User-defined	

HFC and PFC mitigation cost (point of use plasma) (2005$/tCO2e)

	1	
1	EPA assumption (default)	11.63
2	User-defined	

HFC and PFC maximum mitigation reduction potential (point of use plasma)

	1	
1	EPA assumption (default)	7%
2	User-defined	

HFC and PFC mitigation cost (thermal destruction) (2005$/tCO2e)

	1	
1	EPA assumption (default)	42.42
2	User-defined	

HFC and PFC maximum mitigation reduction potential (thermal destruction)

	1	
1	EPA assumption (default)	19%
2	User-defined	

HFC and PFC mitigation cost (catalytic destruction) (2005$/tCO2e)

	1	
1	EPA assumption (default)	10.84
2	User-defined	

HFC and PFC maximum mitigation reduction potential (catalytic destruction)

	1	
1	EPA assumption (default)	21%
2	User-defined	

HFC mitigation cost for refrigerants (distributed system) (2005$/tCO2e)

	1	
1	EPA assumption (default)	-8.17
2	User-defined	

HFC - REFRIGERANTS (not including mobile air conditioning)

HFC maximum mitigation reduction potential (distributed system)

1

1	EPA assumption (default)	4%
2	User-defined	

HFC mitigation cost (Ammonia secondary loop system) (2005$/tCO2e)

1

1	EPA assumption (default)	19.74
2	User-defined	

HFC maximum mitigation reduction potential (Ammonia secondary loop system)

1

1	EPA assumption (default)	4%
2	User-defined	

HFC mitigation cost (HFC secondary loop system) (2005$/tCO2e)

1

1	EPA assumption (default)	20.18
2	User-defined	

HFC maximum mitigation reduction potential (HFC secondary loop system)

1

1	EPA assumption (default)	1%
2	User-defined	

SF-6 - SOLVENTS

SF-6 mitigation cost (alternative solvents) (2005$/tCO2e)

1

1	EPA assumption (default)	0.26
2	User-defined	

SF-6 maximum mitigation reduction potential (alternative solvents)

1

1	EPA assumption (default)	30%
2	User-defined	

SF-6 mitigation cost (NIK replacements) (2005$/tCO2e)

1

1	EPA assumption (default)	4,118
2	User-defined	

SF-6 maximum mitigation reduction potential (NIK replacements)

1

1	EPA assumption (default)	3%
2	User-defined	

SF-6 mitigation cost (Retrofit options) (2005$/tCO2e)

1

1	EPA assumption (default)	78.64
2	User-defined	

SF-6 maximum mitigation reduction potential (Retrofit options)

1

1	EPA assumption (default)	2%
2	User-defined	

RCI-6. Non-Utility Strategies and Incentives To Encourage Energy Efficiency and Reduce GHG Emissions

Start-up year for option

	1	
1	Use	2013
2	User-defined	

Average energy savings from application of measures associated with non-utility strategies and incentives in the residential sector (% relative to Reference Case)

	1	
1	Use	13%
2	User-defined	

Average energy savings from application of measures associated with non-utility strategies and incentives in the commercial sector (% relative to Reference Case)

	1	
1	Use	13%
2	User-defined	

Average energy savings from application of measures associated with non-utility strategies and incentives in the industrial sector (% relative to Reference Case)

	1	
1	Use	15%
2	User-defined	

Annual technical assistance visits to residential sector customers

	1	
1	Use	10,000
2	User-defined	

Annual technical assistance visits to comercial sector customers

	1	
1	Use	1,500
2	User-defined	

Annual technical assistance visits to industrial sector customers

	1	
1	Use	300
2	User-defined	

RCI-7. Conservation Improvement-Type Program for Propane and Fuel Oil Efficiency

Assumed start year for the option

2009

Equipment efficiency improvement target for fuel oil

1

1	Efficiency of equipment using fuel oil improves from	80%	to	85%	(default)
2	User-defined (Efficiency of equipment using fuel oil improves from	80%	to	85%	

Ramp-up period for achieving the efficiency improvement target for fuel oil in MN (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 efficient fuel oil equipment

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%
2009					17%	34%	51%	68%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
2010						0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2011							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%
2013									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%
2015											0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2016												0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2017													0%	0%	0%	0%	0%	0%	0%	0%	0%
2018														0%	0%	0%	0%	0%	0%	0%	0%
2019															0%	0%	0%	0%	0%	0%	0%
2020																0%	0%	0%	0%	0%	0%
2021																	0%	0%	0%	0%	0%
2022																		0%	0%	0%	0%
2023																			0%	0%	0%
2024																				0%	0%
2025																					0%
efficiency	0%	0%	0%	0%	17%	34%	51%	68%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Share	0%	0%	0%	0%	20%	40%	60%	80%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Equipment efficiency improvement target for propane

1

1	Efficiency of equipment using proane improves from	85%	to	90%	(default)
2	User-defined (Efficiency of equipment using propane improves fror	85%	to	90%	

Ramp-up period for achieving the efficiency improvement target for propane in MN (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 efficient propane equipment

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%
2009					18%	36%	54%	72%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
2010						0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2011							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%
2013									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%
2015											0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2016												0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2017													0%	0%	0%	0%	0%	0%	0%	0%	0%
2018														0%	0%	0%	0%	0%	0%	0%	0%
2019															0%	0%	0%	0%	0%	0%	0%
2020																0%	0%	0%	0%	0%	0%
2021																	0%	0%	0%	0%	0%
2022																		0%	0%	0%	0%
2023																			0%	0%	0%
2024																				0%	0%
2025																					0%
efficiency	0%	0%	0%	0%	18%	36%	54%	72%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Share	0%	0%	0%	0%	20%	40%	60%	80%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Percentage of new fuel oil use subject to the new efficiency standards

	1			
1	Use	100%		
2	User-defined		*50%*	*since not user-defined, ignore value in cell at left*

Percentage of new propane use subject to the new efficiency standards

	1			
1	Use	100%		
2	User-defined		*####*	*since not user-defined, ignore value in cell at left*

Percentage of existing fuel oil use subject to the new efficiency standards

	1			
1	Use	50%		
2	User-defined		*25%*	*since not user-defined, ignore value in cell at left*

Percentage of existing propane use subject to the new efficiency standards

	1			
1	Use	50%		
2	User-defined		*50%*	*since not user-defined, ignore value in cell at left*

CO2e emission factors (tCO2e per mmbtu)

0.07	diesel fuel oil
0.06	propane

Payback period for efficient equipment (years)

	1					
		oil	ropane			
1	Use	14	6			
2	User-defined			*14*	*7*	*since not user-defined, ignore values in cells at left*

Lifespan for efficient equipment (years)

	1					
		oil	ropane			
1	Use	30	8			
2	User-defined			*30*	*25*	*since not user-defined, ignore values in cells at left*

Real discount rate

	1			
1	Use	5%		
2	User-defined		*4%*	*since not user-defined, ignore value in cell at left*

RCI-10. Support Strong Federal Appliance Standards and Require High State Standards in the Absence of Federal Standards

Summary of national savings from appliance standards on appliances not currently covered by federal statutes

Source: "Leading the Way: Continued Opportunities for New State Appliance and Equipment Efficiency Standards", 2005, by Steven Nadel, Andrew deLaski, Jim Kleisch, and Toru Kubo, available at http://www.standardsasap.org/documents/a051.pdf; page v.

		2020 savings		2030 savings		NPV (2030)	
#	Technology	TWh	trillion btu	TWh	trillion btu	billion $	Start year
1	Ceiling fan lights	18.9	197	18.9	190	13	2007
2	Commercial clothes washers	0.3	9	0.3	9	0.9	2007
3	Commercial ice-makers	0.6	7	0.6	6	0.4	2007
4	Commercial refrigerators & freezers	2.4	25	2.4	24	1.3	2010
5	Commercial unit heaters	0	39	0	55	3	2007
6	Dehumidifiers	1	10	1.1	11	0.7	2007
7	Digital cable & satellite boxes	1.4	14	1.4	14	1.2	2007
8	Digital television adapters	0.3	3	0	0	1.1	2007
9	Exit signs	1.7	18	2.9	29	1.4	2007
10	External power supplies	4.9	51	4.9	49	3.3	2007
11	Large commercial packaged AC & heat pumps	1.5	16	2.2	22	0.9	2010
12	Low-voltage dry-type transformers	3.1	32	5.4	54	2.6	2007
13	Medium-voltage dry-type transformers	2.7	28	4.7	47	2.4	2007
14	Metal halide lamp fixtures	9	93	14.4	144	7.3	2008
15	Pre-rinse spray valves	0	56	0	56	8	2007
16	Reflector lamps	3.9	40	3.9	39	2.6	2007
17	Torchiere lighting fixtures	11.8	123	11.8	119	8.4	2007
18	Traffic signals	1.3	13	1.3	13	0.6	2007
	total	64.8	774	76.2	881	59.1	

Natural gas savings

Source: "Leading the Way: Continued Opportunities for New State Appliance and Equipment Efficiency Standards", 2005, by Steven Nadel, Andrew deLaski, Jim Kleisch, and Toru Kubo, available at http://www.standardsasap.org/documents/a051.pdf; page v.

1.03 mmbtu per MCF

	Savings - All fuels		Savings Estimate - Natural Gas					
	trillion btu		billion cubic feet		trillion btu		NG Share ot total	
	2020	2030	2020	2030	2020	2030	2020	2030
Demand side			100		103	117	13%	13%
Supply side			336		346	394	45%	45%
total	774	881	436		449	511	58%	58%

Cost of electricity used for estimating economic benefits of appliance standards in the Nadel et al report

Source: "Leading the Way: Continued Opportunities for New State Appliance and Equipment Efficiency Standards", 2005, by Steven Nadel, Andrew deLaski, Jim Kleisch, and Toru Kubo, available at http://www.standardsasap.org/documents/a051.pdf; page 64.
Sectoral shares of total residential/commercial electricity use from the MN GHG inventory and forecast called GHGemitsum07_Working.xls ("Energy Use and CO2" worksheet) prepared by R. Strait

	Cents/kWh (MN)		$/MWh (MN)	
	2003$	2005$	2003$	2005$
Residential electricity price	7.7	8.1	77	81
Commercial electricity price	6.1	6.4	61	64
Residential sector electricity share (2005)	50.12%			
Commercial sector electricity share (2005)	49.88%			
Average	6.9	7.3	69	73

Estimate of the cost of achiecing electricity savings from appliance standards

Source: "Leading the Way: Continued Opportunities for New State Appliance and Equipment Efficiency Standards", 2005, by Steven Nadel, Andrew deLaski, Jim Kleisch, and Toru Kubo, available at http://www.standardsasap.org/documents/a051.pdf; page 42.

cost (2005$/MWh)	$11.90

MN avoided electricity costs

Source: avoided cost calculations for this study

MN avoided cost (2005$/MWh)	$156

Adjustment factor to apply to NPV

Source: Adjustment factor that scales the NPV by the ratio of the MN net avoided cost and the USA net avoided cost

Adjustment factor	2.39

Share of NPV associated with electricity savings

Source: estimate of the share of savings from appliance standards associated with electricity

	2020	2030
rough assumption	87%	87%

Appendix G
Energy Supply Sector
Policy Recommendations

Summary List of Policy Recommendations

Policy No.	Policy Recommendations	GHG Reductions (MMtCO$_2$e)			Net Present Value 2008–2025 (Million $)	Cost-Effective-ness ($/tCO$_2$e)	Level of Support
		2015	2025	Total (2008–2025)			
ES-1	Generation Performance Standard	0.0	0.0	0.0	$0.0	$0.0	Majority (16 objections)
ES-3	Efficiency Improvements, Re-powering, and Other Upgrades to Existing Plants	1.8	3.0	33.3	$554.4	$16.7	Unanimous
ES-4	Transmission System Upgrading, Including Reducing Transmission Line and Distribution System Loss	0.2	0.4	3.9	–$92.2	–$26.1	Unanimous
ES-5	Renewable and/or Environmental Portfolio Standard*	*Quantified as a "Recent Action"*					Enacted
ES-6	Nuclear Power Support and Incentives	*Recommended for further study.*					Unanimous
ES-8	Advanced Fossil Fuel Technology Incentives, Support, or Requirements, Including Carbon Capture and Storage	*Recommended for further study.*					Unanimous
ES-10	Voluntary GHG targets	*Not quantified*					Unanimous
ES-12	Distributed Renewable Energy Incentives and/or Barrier Removal	0.021	0.023	0.37	$29.1	$78.1	Unanimous
ES-13	Technology-Based Approaches, Including Research and Development, Fuel Cells, Energy Storage, Distributed Renewable Energy Technologies, etc.	*Not quantified*					Unanimous
	Sector Total After Adjusting for Overlaps	**2.0**	**3.4**	**37.5**	**$462.2**	**$12.3**	
	Reductions From Recent Actions	**12.8**	**20.8**	**225.0**	**$10,116**	**$45.0**	
	Biomass for Electricity	**0.60**	**0.60**	**11.4**	**$285.3**	**$25.0**	
	Metro Emissions Reduction Project	**4.52**	**4.52**	**80.4**	**$2,330**	**$29.0**	
	ES-5: Renewable Energy Standard*	**7.72**	**15.7**	**133.1**	**$7,502**	**$56.4**	
	Sector Total Plus Recent Actions	**14.8**	**24.2**	**262.5**	**$10,578.8**	**$40.3**	

GHG = greenhouse gas; MMtCO$_2$e = million metric tons of carbon dioxide equivalent; $/tCO$_2$e = dollars per metric ton of carbon dioxide equivalent.

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

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

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

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

ES-1. Generation Performance Standard

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

Policy Description

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

Policy Design

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

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

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

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

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

Implementation Mechanisms

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

Related Policies/Programs in Place

None.

Type(s) of GHG Reductions

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

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources:

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

Quantification Methods:

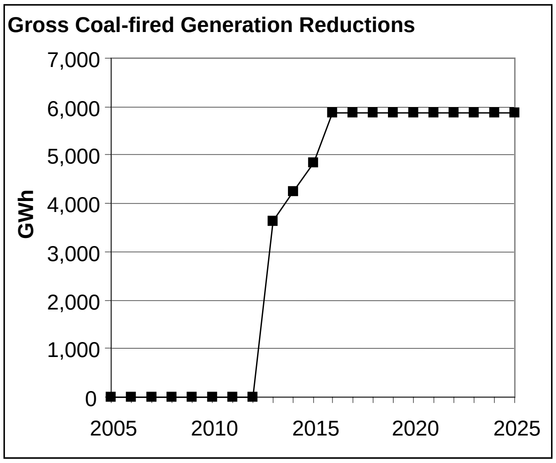
This policy is a mandate requiring entities that deliver electricity to acquire electricity, or power plant developers to build and operate new base-load generation, with a per-unit emission rate below a specified mandatory standard (1,110 pounds [lb] of CO_2/MWh for power stations, and 1,300 lb of CO_2/MWh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

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

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

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

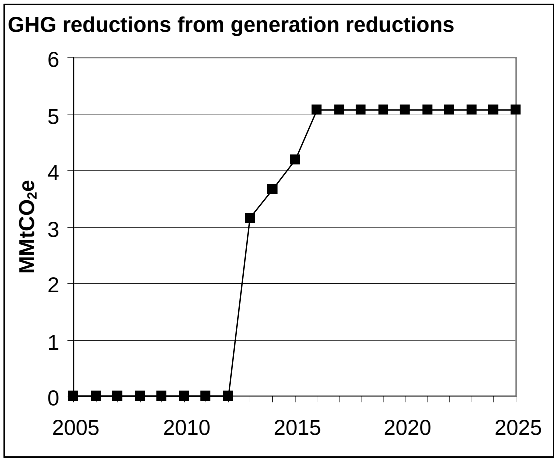
Figure G-1. Minnesota planned coal-fired generation



GWh = gigawatt-hours.

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

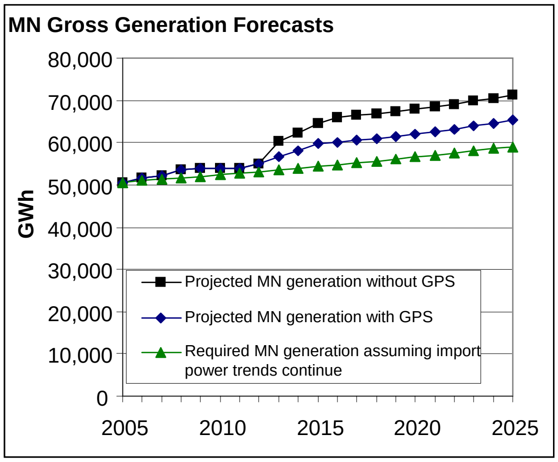
Figure G-2. Annual CO_2e reductions from elimination of planned coal-fired generation in Minnesota



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

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

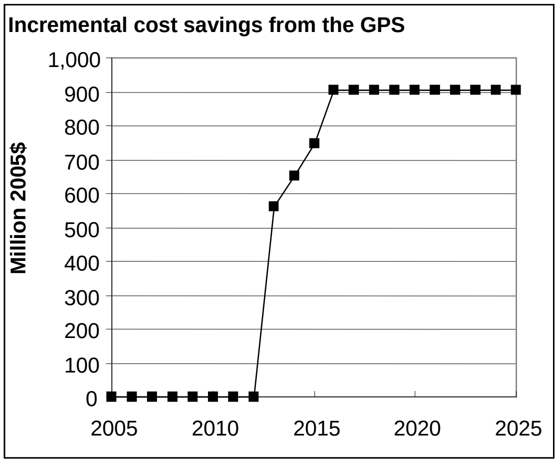
Figure G-3. Projected and required gross generation in Minnesota



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

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

Figure G-4. Incremental cost savings from the GPS



GPS = generation performance standard.

Cost-effectiveness was calculated as the quotient of the NPV and cumulative GHG emission reductions, –$120/tCO$_2$e reduced (2005$) (i.e., –$7.4 billion divided by 61.8 MMt and multiplied by a conversion factor of 1,000).

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

Key Assumptions: See Annex 1.

Key Uncertainties

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

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

Additional Benefits and Costs

Reduced air pollution.

Feasibility Issues

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

Status of Group Approval

Complete.

Level of Group Support

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

Barriers to Consensus

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

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

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

Policy Description

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

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

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

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

Policy Design

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

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

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

Implementation Mechanisms

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

Related Policies/Programs in Place

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

Type(s) of GHG Reductions

Avoided emissions from fossil-fuel generation.

Estimated GHG Reductions and Net Costs or Cost Savings

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

Quantification Methods:

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

Primary Analysis: Biomass Co-Firing at Minnesota Coal Stations

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

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

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

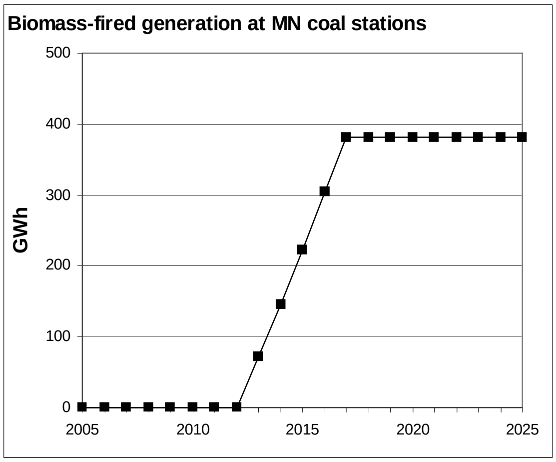
Sensitivity Analysis: Natural Gas Repowering of an Existing 600-MW Coal Station in Minnesota

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

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

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

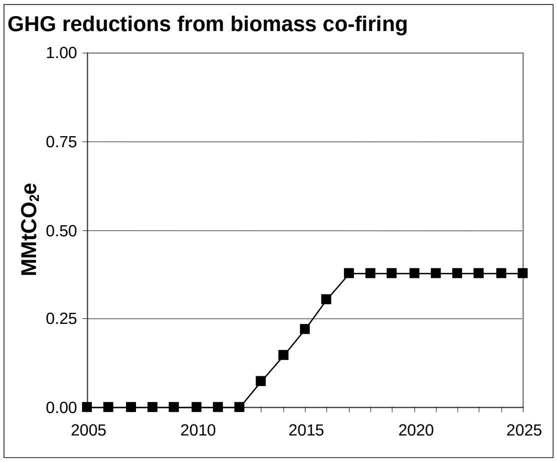
Figure G-5. Projected generation of co-fired biomass at Minnesota coal stations



GWh = gigawatt-hours.

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

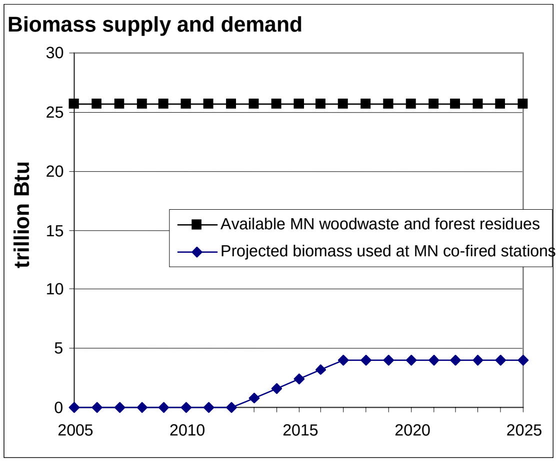
Figure G-6. Projected GHG reductions from biomass co-firing in Minnesota



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

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

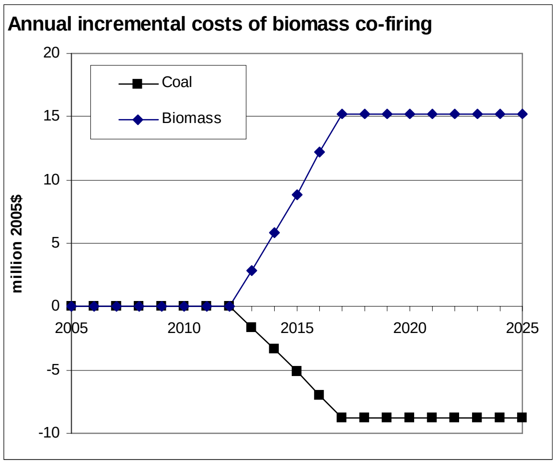
Figure G-7. Impact of biomass co-firing on biomass supply and demand in Minnesota



Btu = British thermal units.

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

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



The cost-effectiveness of the policy was calculated for Reference Scenario #1 as the quotient of the NPV and cumulative GHG emission reductions, or $12/t$CO_2$e reduced (2005$) (i.e., $0.05 billion divided by 4.2 MMt and multiplied by a conversion factor of 1,000).

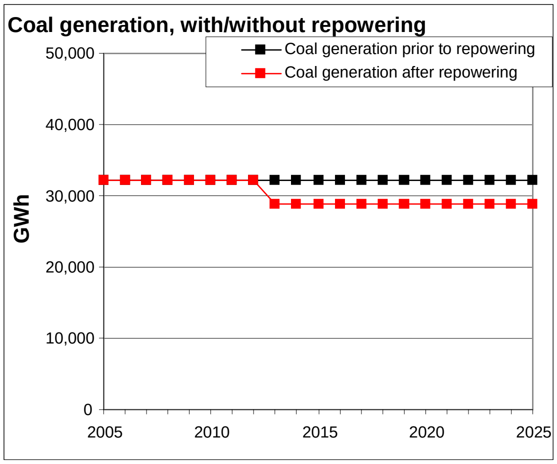
Sensitivity Analysis: Natural Gas Repowering of an Existing 600-MW Coal Station in Minnesota

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

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

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

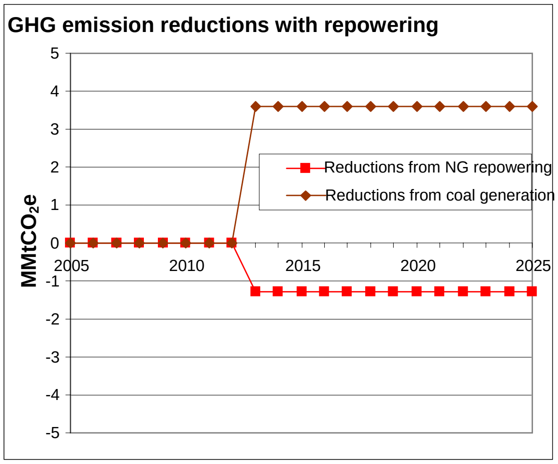
Figure G-9. Impact on coal generation with and without repowering



GWh = gigawatt-hours.

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

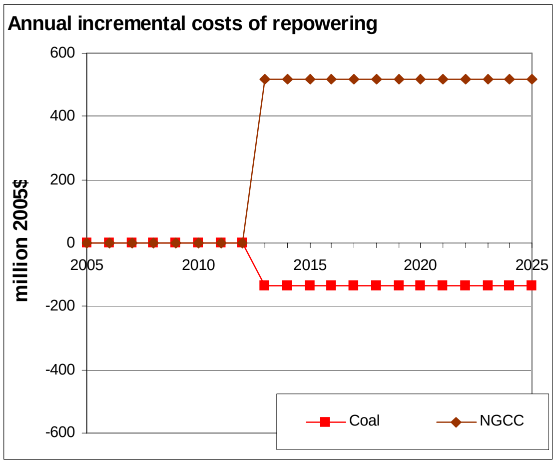
Figure G-10. GHG emission reductions from repowering



MMtCO$_2$e = million metric tons of carbon dioxide equivalent; NG = natural gas.

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

Figure G-11. Annual incremental costs of repowering



NGCC = natural gas combined-cycle.

The cost-effectiveness of this policy was calculated for Reference Scenario #1 as the quotient of the NPV and cumulative GHG emission reductions, or $120/tCO$_2$e reduced (2005$) (i.e., $3.6 billion divided by 29.9 MMt and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 1.

Key Uncertainties

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

Additional Benefits and Costs

Reduced air pollution associated with displaced coal generation.

Feasibility Issues

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

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

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

Policy Description

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

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

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

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

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

Policy Design

Goals:

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

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

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

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

Implementation Mechanisms

As noted above.

Related Policies/Programs in Place

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

Type(s) of GHG Reductions

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

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources:

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

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

Quantification Methods:

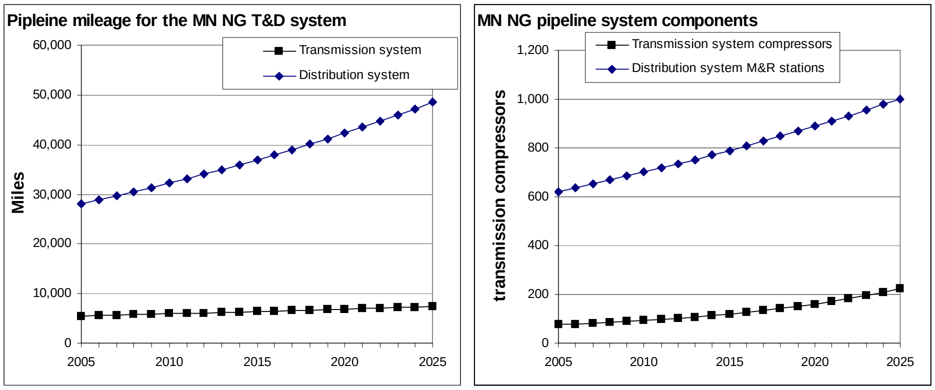
This policy would improve electricity transmission systems to reduce bottlenecks, enhance throughput, and improve the efficiency of operations system-wide. It also targets reduction of leaks in natural gas pipelines to avoid methane emissions to the atmosphere and prevent the waste of valuable product.

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

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

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

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



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

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

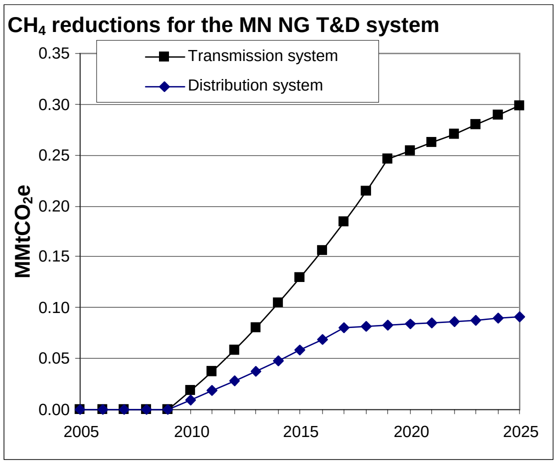
- Implementing directed inspection and maintenance at compressor stations,
- Reducing methane emissions from compressor rod packing systems,
- Replacing wet seals with dry seals in centrifugal compressors,
- Implementing directed inspection and maintenance at gate stations and surface facilities,
- Converting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

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

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

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

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



NG = natural gas; T&D = transmission and distribution; MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

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

The cost-effectiveness of the policy was calculated as the quotient of the NPV and cumulative GHG emission reductions, or –$26/tCO$_2$e reduced (2005$) (i.e., –$0.093 billion divided by 3.9 MMt and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 1.

Key Uncertainties

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

Additional Benefits and Costs

None.

Feasibility Issues

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

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

ES-5. Renewable and/or Environmental Portfolio Standard

Policy Description

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

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

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

Policy Design

Goals:

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

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

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

Implementation Mechanisms

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

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

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

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

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

Related Policies/Programs in Place

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

Minnesota Statutes 2007, Chapter 216.

Type(s) of GHG Reductions

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

Estimated GHG Reductions and Net Costs or Cost Savings

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

Quantification Methods:

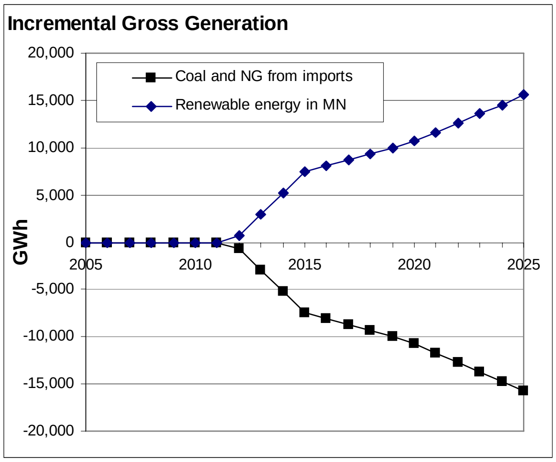
This policy requires that utilities and other load-serving entities to supply a certain, generally fixed, percentage of electricity from eligible (e.g., low-GHG-emitting) renewable energy sources. The current Minnesota statute through 2025—25% renewable energy as a percentage of sales—was modeled.

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

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

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

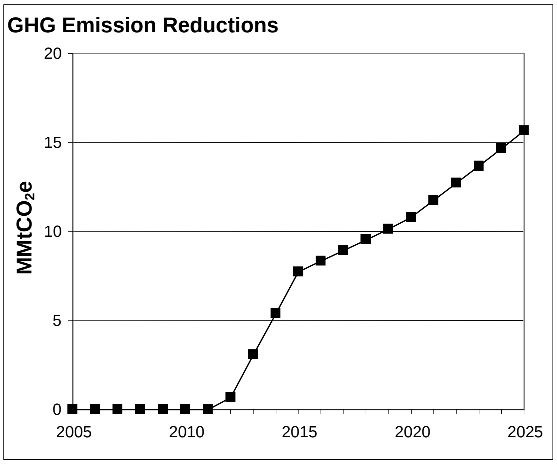
Figure G-14. Impacts of an RES on incremental gross generation in Minnesota



NG = natural gas; GWh = gigawatt-hours.

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

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



GHG = greenhouse gas; MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

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

The cost-effectiveness of this policy was calculated as the quotient of the NPV and cumulative GHG emission reductions, or $35.5/tCO$_2$e reduced (2005$) (i.e., $4.7 billion divided by 133.1 MMt and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 1.

Key Uncertainties

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

Additional Benefits and Costs

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

Feasibility Issues

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

Status of Group Approval

Complete.

Level of Group Support

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

Barriers to Consensus

Not applicable.

ES-6. Nuclear Power Support and Incentives

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

Policy Description

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

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

Policy Design

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

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

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

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

Implementation Mechanisms

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

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

Related Policies/Programs in Place

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

Type(s) of GHG Reductions

Avoided emissions from fossil fuel generation.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources:

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

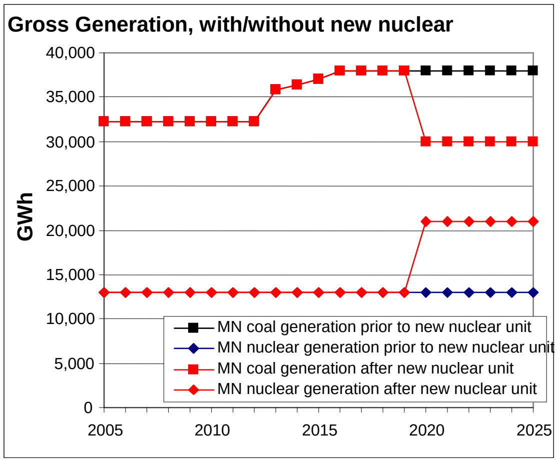
Quantification Methods:

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

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

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

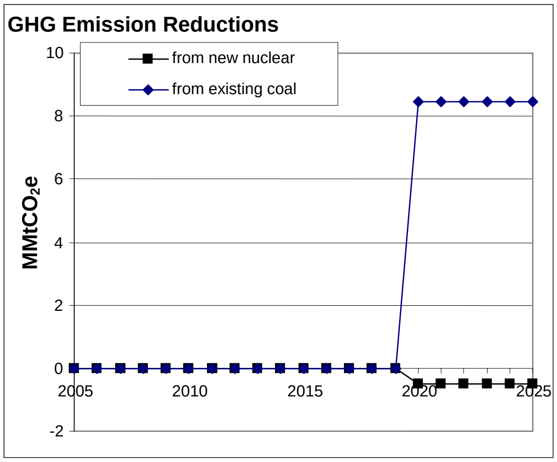
Figure G-16. Impacts on gross generation, with and without new nuclear power



GWh = gigawatt-hours.

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

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



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

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

The cost-effectiveness of this policy was calculated as the quotient of the NPV and cumulative GHG emission reductions, or $70.2/tCO$_2$e reduced (2005$) (i.e., $3.4 billion divided by 47.8 MMt and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 1.

Key Uncertainties

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

Additional Benefits and Costs

None.

Feasibility Issues

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

Status of Group Approval

Complete.

Level of Group Support

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

Barriers to Consensus

Not applicable.

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

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

Policy Description and Design

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

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

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

Implementation Mechanisms

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

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

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

Related Policies/Programs in Place

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

Type(s) of GHG Reductions

Reductions in CO_2 emissions from coal combustion.

Estimated GHG Reductions and Net Costs or Cost Savings

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

Quantification Methods:

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

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

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

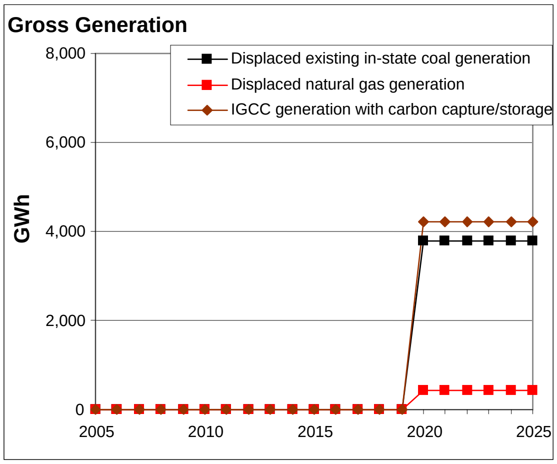
Primary Analysis: New IGCC With Carbon Capture and Storage

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

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

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

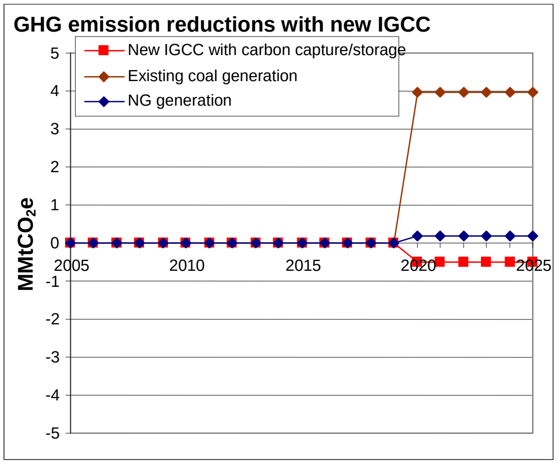
Figure G-18. Impacts of a new IGCC station with carbon capture and storage on gross generation



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

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

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



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

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

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

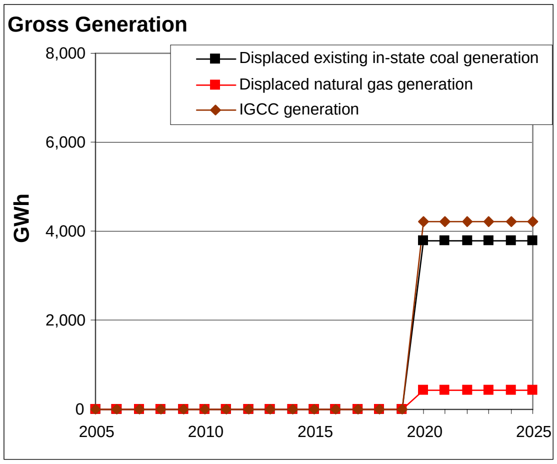
Sensitivity Analysis #1: New IGCC Without Carbon Capture and Storage

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

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

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

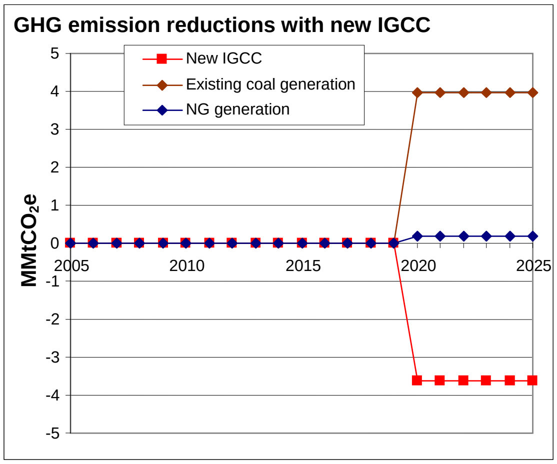
Figure G-20. Impacts of a new IGCC station without carbon capture and storage on gross generation



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

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

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



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

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

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

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

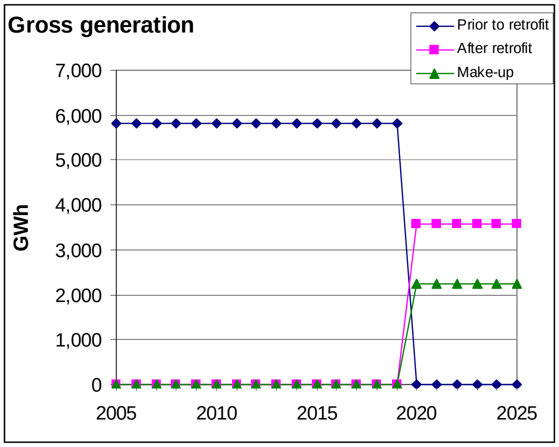
The key assumptions for this sensitivity analysis of this policy are as follows:

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

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

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

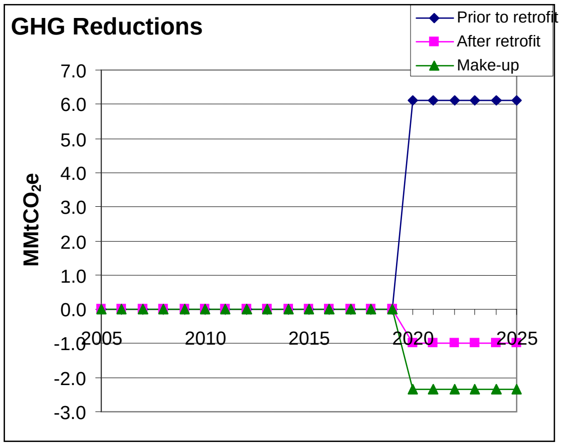
Figure G-22. Impacts on gross generation from retrofitting existing pulverized coal stations with carbon capture and storage



GWh = gigawatt-hours.

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

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



GHG = greenhouse gas; MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

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

The cost-effectiveness of this policy was calculated as the quotient of the NPV and cumulative GHG emission reductions, or $97.2/tCO$_2$e reduced (2005$) (i.e., $1.6 billion divided by 16.7 MMt and multiplied by a conversion factor of 1,000).

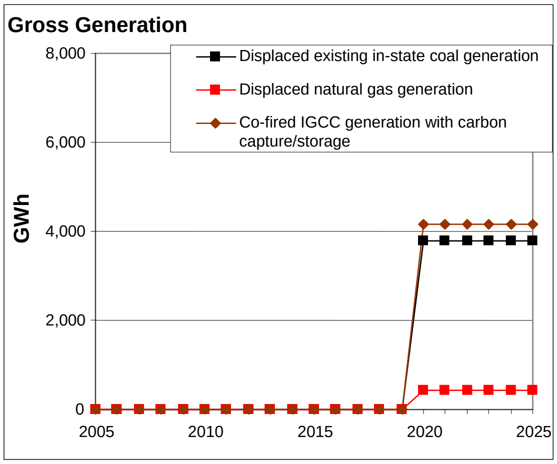
Sensitivity Analysis #3: New IGCC With 1% Biomass Co-Firing and Carbon Capture and Storage

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

- The start year is 2020.
- One 600-MW IGCC station is installed.
- The resources displaced by the new IGCC plant are assumed to be 10% natural gas-fired generation from combustion turbines in- and out-of-state, with the balance from existing in-state coal-fired generation.
- The capital costs associated with displaced resources are not depreciated.
- A heat rate penalty of 1,530 Btu/kWh above the assumed IGCC heat rate of 9,000 Btu/kWh is assumed to be the effect of adding carbon capture and storage technology.
- A carbon capture efficiency rate of 86% is assumed from adding carbon capture and storage technology.
- A geologic storage site is located within 150 miles of the IGCC unit connected by a pipeline with a mass flow rate of 22.5 MtCO$_2$/year.
- Coal is co-fired with biomass at 1% on an energy basis.

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

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



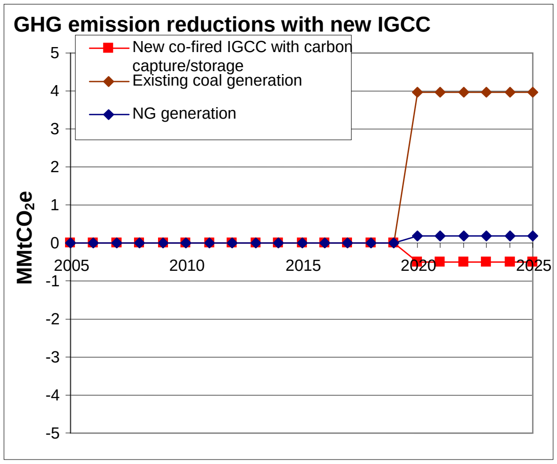
IGCC = integrated gasification combined-cycle; GWh = gigawatt-hours.

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

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

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

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



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

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

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

Key Assumptions: See Annex 1.

Key Uncertainties

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

Additional Benefits and Costs

Installation of more efficient technology.

Feasibility Issues

The technology is currently in the demonstration stage.

Status of Group Approval

Complete.

Level of Group Support

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

Barriers to Consensus

Not applicable.

ES-10. Voluntary GHG targets

Policy Description

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

Policy Design

Goals: The goals for a Minnesota Voluntary GHG program include

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

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

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

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

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

Timing: Upon promulgation.

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

Other: Not applicable.

Implementation Mechanisms

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

Related Policies/Programs in Place

None.

Type(s) of GHG Reductions

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

Estimated GHG Reductions and Net Costs or Cost Savings

By consensus, this option was not quantified.

Data Sources: Not applicable.

Quantification Methods: Not applicable.

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

Key Uncertainties

Not applicable.

Additional Benefits and Costs

None.

Feasibility Issues

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

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

None.

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

Policy Description

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

Policy Design

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

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

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

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

Implementation Mechanisms

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

Related Policies/Programs in Place

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

Type(s) of GHG Reductions

Reductions in CO_2 emissions from combustion sources.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources:

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

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

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

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

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

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

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

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

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

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

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

Quantification Methods:

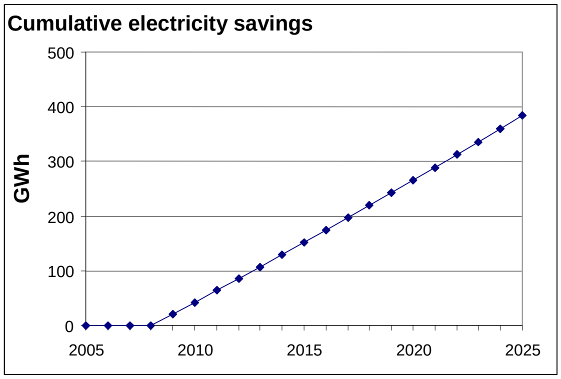
This policy encourages investment in small-scale distributed renewable energy via incentives and/or the prevention of barriers. It has been modeled as a penetration of solar photovoltaic technology in new residential housing and commercial establishments.

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

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

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

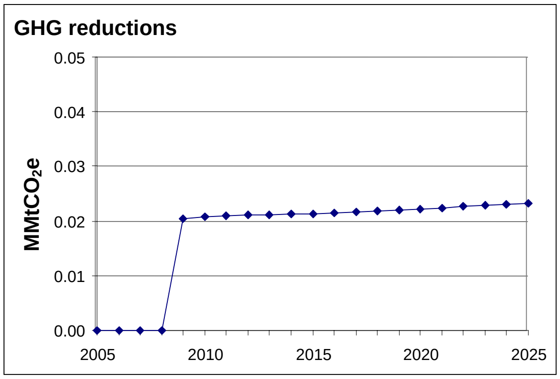
Figure G-26. Cumulative electricity savings from distributed renewable energy



GWh = gigawatt-hours.

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

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



GHG = greenhouse gas; MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

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

The cost-effectiveness of this policy was calculated as the quotient of the NPV and cumulative GHG emission reductions, or $78.1/tCO$_2$e (2005$) (i.e., $0.029 billion divided by 0.37 MMt and multiplied by a conversion factor of 1,000).

Key Assumptions: See Annex 1.

Key Uncertainties

None.

Additional Benefits and Costs

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

Feasibility Issues

Structuring of the incentive.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

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

Policy Description

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

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

Policy Design

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

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

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

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

Implementation Mechanisms

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

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

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

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

Related Policies/Programs in Place

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

Renewable Development Fund.

Tax credits and federal incentives.

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

Type(s) of GHG Reductions

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

Estimated GHG Reductions and Net Costs or Cost Savings

By consensus, this option was not quantified.

Data Sources: Not applicable.

Quantification Methods: Not applicable.

Key Assumptions: Not applicable.

Key Uncertainties

Funding level stability

Ability to identify productive technology pathways

Measures of success and program oversight

Additional Benefits and Costs

None.

Feasibility Issues

Requires broad range of skills for effective administration.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

None.

ES Reductions from Recent Actions

Summary List of Recent Actions

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

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

Renewable Energy Production Incentives

Policy Description

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

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

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

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

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

Policy Design

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

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

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

Implementation Mechanisms

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

Related Policies/Programs in Place

See policy description.

Type(s) of GHG Reductions

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

Estimated GHG Reductions and Net Costs or Cost Savings

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

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

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

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

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

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

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

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

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

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

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

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

GWh = gigawatt hours

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

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

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

GWh = gigawatt hours

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

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

Key Uncertainties

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

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

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

Additional Benefits and Costs

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

Feasibility Issues

Unknown.

Status of Group Approval

Unknown.

Level of Group Support

Unknown.

Barriers to Consensus

Unknown.

Biomass for Electricity (2005–2007)

Policy Description

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

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

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

Policy Design

None.

Implementation Mechanisms

None.

Related Policies/Programs in Place

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

Type(s) of GHG Reductions

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

Estimated GHG Reductions and Net Costs or Cost Savings

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

	Option Name	GHG Reductions ($MMtCO_2e$)			NPV of Costs $/MMtCO$_2$e (2005)	Cost of Saved Carbon (2005$/tCO$_2$e avoided)
		2015	2025	Total (2008–2025)		
	Capture Existing Biomass Electricity Generation	0.6	0.6	11.4	$285	$25.0

NPV = net present value

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

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

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

Key Uncertainties

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

Additional Benefits and Costs

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

Feasibility Issues

None.

Status of Group Approval

Unknown.

Level of Group Support

Unknown.

Barriers to Consensus

Unknown.

Metro Emissions Reduction Plan (MERP)

Policy Description

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

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

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

Policy Design

None.

Implementation Mechanisms

None.

Related Policies/Programs in Place

None.

Type(s) of GHG Reductions

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

Estimated GHG Reductions and Net Costs or Cost Savings

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

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

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

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

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

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

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

Key Uncertainties

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

Additional Benefits and Costs

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

Feasibility Issues

None.

Status of Group Approval

Unknown.

Level of Group Support

Unknown.

Barriers to Consensus

Unknown.

Annex 1: Key Assumptions

ES-1. Generation Performance Standard

Start year for GPS 2013

CO2e emission intensity threshold assumptions

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

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

1

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

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

1

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

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

1

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

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

1

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

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

2

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

please fill in the table

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

Levelized cost raw inputs (2005$/MWh)

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

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

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

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

Start year for option 2013

Biomass co-firing assumption

2

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

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

1

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

Phase-in for co-firing portion

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

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

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

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

Number of NGCC repowered coal stations units 1

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

Characteristics of power stations

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

Levelized cost assumptions (2005$/MWh)

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

ES-4. Natural Gas Transmission and Distribution Upgrades

Start year for transmission option

2010

Transmission system reduction in emissions (%)

1

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

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

1

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

Phase-in for trasnmission system upgrading

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

Start year for distribution system option

2010

Distribution system reduction in emissions (%)

1

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

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

1

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

Phase-in for distribution system upgrading

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

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

Conversion factors

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

Real discount rate

5%

Upper limit of emission reductions relative annual emissions

80% assumption

Natural gas savings by each mitigation option considered

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

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

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

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

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

ES-5. Renewable and/or Environmental Portfolio Standard

Start year for RPS

2011

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

1

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

Share of backed down imported NG generation that is fully depreciated

1

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

Natural gas capacity composition - All Scenarios

Combustion turbine	100%
Combined cycle	0%
total	100%

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

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

ES-6. Nuclear Power Support and Incentives

Online year for new nuclear power

2020

Upstream fuel stages considered?

1

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

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

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

Resource displaced	100%	coal

CO2 emissions of nuclear fuel cycle

0.06	tonnes CO2 per MWh electricity produced

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

CO2e emission factors (tonnes of CO2e per mmbtu)

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

Fuel cycle inputs

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

		Additional tonnes CO2e per MMBtu associated with upstream fuel cycle stages								
Stages of coal fuel cycle	Considered?	Natural gas	petroleum	Coal	gasoline	diesel	heavy fuel oil	Biomass	electricity (end use)	Total
Extraction	Yes	0.0000	0.0004	0.0001	0.0000	0.0003	0.0000	0.0000	NA	0.0008
Beneficiation and processing	Yes	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	NA	0.0000
Transport to power station	Yes	0.0000	0.0000	0.0000	0.0000	0.0007	0.0000	0.0000	NA	0.0007
Total	NA	0.0000	0.0004	0.0001	0.0000	0.0010	0.0000	0.0000	NA	0.0015

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

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

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

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

Number of new IGCC/CCR units	1
Online year for new IGCC/CCR unit(s)	2020
Carbon capture & storage?	Yes
Coal CO2e emission factor (tCO2e/mmbtu)	0.0959
Sensitivities for CCR technology	1

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

Cost & performance characteristics of new IGCC power stations

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

Cost & performance characteristics of new carbon capture & storage technology

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

Resource displaced

2

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

Financial status of displaced resource

1

1 not depreciated
2 fully depreciated (default)

Levelized cost assumptions (2005$/MWh)

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

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

Number of new IGCC units

1

Online year for new IGCC unit(s)

2020

Carbon capture & storage?

No

Characteristics of new IGCC power stations

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

Resource displaced

2

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

Financial status of displaced resource

1

1 not depreciated (default)
2 fully depreciated

Levelized cost assumptions (2005$/MWh)

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

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

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

Assumed retrofitting costs for coal stations for carbon capture

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

Incremental cost components for carbon capture

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

Incremental levelized costs (including escalation)

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

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

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

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

Assumed cost and performance characteristics of make-up power

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

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

Number of new IGCC/CCR units	1
Online year for new IGCC/CCR unit(s)	2020
Carbon capture & storage?	Yes
Coal CO2e emission factor (tCO2e/mmbt	0.0959

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

Resource displaced

2

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

Financial status of displaced resource

1

1 not depreciated
2 fully depreciated (default)

Levelized cost assumptions (2005$/MWh)

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

Biomass co-firing assumption

2

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

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

1

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

Phase-in for co-firing portion

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

Biogenic biomass emission factor

29.9 tC per TJ
0.12 tCO2/mmbtu

Levelized biomass fuel price (2005$/MWh)

40

ES-12. Distributed Renewable Generation

Assumed start year for option

2009

Distributed renewable resource

Solar photovoltaics

Assumption for penetration of residential distributed renewable systems in new homes

1

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

Assumption for penetration of commercial distributed renewable systems in new buildings

1

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

Marginal resource associated with electricity savings

1

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

Real discount rate

1

1	Use	5%
2	User-defined	

Levelized costs for distributed renewables (2005$/MWh)

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

Assuemd capital cost decrease over time?

2

1	Yes
2	No (default)

Avoided costs for electric supply (2005$/MWh)

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

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

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

	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 Struc- tures 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

Appendix H
Transportation and Land Use

Summary List of Policy Recommendations

Policy No.	Policy Recommendation	GHG Reductions (MMtCO$_2$e)			Net Present Value 2008–2025 (Million $)	Cost-Effective-ness ($/tCO$_2$e)	Level of Support
		2015	2025	Total 2008–2025			
TLU Area 1. Reduce VMT (VMT goal to be established based on VMT implied by selected strategies)							
TLU-1	Improved Land-Use Planning and Development Strategies	0.7	1.9	14.9	*Net savings*	*Net savings*	Unanimous
TLU-2	Expand Transit, Bicycle, and Pedestrian Infrastructure	0.1	0.3	3.0	$0	$0	Unanimous
TLU-5	Climate-Friendly Transportation Pricing/Pay-as-You-Drive	1.1	2.1	20.9	–$1	–$1	Super Majority (3 objections)
TLU-7	“Fix-it-First” Transportation Investment Policy and Practice	*Not quantified*					Super Majority (2 objections)
TLU-9	Workplace Tools To Encourage Carpooling, Bicycling, and Transit Ridership	0.3	0.4	4.5	*Large net savings*	*Large net savings*	Unanimous
TLU-14	Freight Mode Shifts: Intermodal and Rail	*N/A*					Super Majority (1 objection)
TLU Area 2: Reduce Carbon per Unit of Fuel							
TLU-3	Low-GHG Fuel Standard	1.7	3.6	36.2	*Not quantified*		Unanimous
TLU Area 3: Reduce Carbon per Mile and/or per Hour							
TLU-4	Infrastructure Management	0.04	0.1	0.7	*Not quantified*		Unanimous
TLU-6	Adopt California Clean Car Standards	0.74	1.16	13.1	–$263	–$39	Majority (16 objections)
TLU-12	Voluntary Fleet Emission Reductions	0.4	0.4	6.1	*Not quantified*		Unanimous
TLU-13	Reduce Maximum Speed Limits	0.4	0.4	6.1	*N/A*	$50 at $2.40/gal –$19 at $3.40/gal	Majority (16 objections)
	Sector Total After Adjusting for Overlaps	**4.7**	**9.3**	**91.2**	***Not quantified***		
	Reductions From Recent Actions	**1.4**	**1.5**	**20.2**	***Not quantified***		
	Biodiesel	**0.64**	**0.75**	**8.1**			
	Ethanol	**0.78**	**0.79**	**12.1**			
	Sector Total Plus Recent Actions	**6.1**	**10.8**	**111.4**	***Not quantified***		

GHG = greenhouse gas; MMtCO$_2$e = million metric tons of carbon dioxide equivalent; VMT = vehicle miles traveled; $/tCO$_2$e = dollars per metric ton of carbon dioxide equivalent; N/A = not available. (TLU Policy Options 8, 10 and 11 were either dropped or merged during the process..)

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

Overall Transportation and Land Use (TLU) Analysis Framework

- Transportation carbon emissions = miles driven × carbon per mile.
- Carbon per mile = vehicle emissions per unit × carbon per unit of fuel.

So, to reduce greenhouse gas (GHG) emissions requires:

TLU Area 1: Reduce the number of miles driven.

TLU Area 2: Reduce carbon per unit of fuel [Cleaner Fuels].

TLU Area 3: Reduce carbon per mile and/or per hour [Improved Vehicle Efficiency].

This Overall TLU Analysis Framework section summarizes for the Minnesota Climate Change Advisory Group (MCCAG) the most important policy option changes since the last MCCAG meeting and is organized by TLU Area.

TLU Area 1: Reduce the number of **miles driven.**

The following policies will all contribute to reducing miles driven:

- TLU-1 Land Use Planning and Development
- TLU-2 Transit, Bicycle, and Pedestrian Infrastructure
- TLU-5 Climate-Friendly Transportation Pricing [in part]
- TLU-7 Fix-It-First
- TLU-9 Commuter Choice
- TLU-14 Freight Mode Shifts: Intermodal and Rail

The following recommendations would reduce vehicle miles traveled (VMT).

Policy No.	Policy Recommendation	GHG Reductions* ($MMtCO_2e$)			Net Present Value 2008–2025 (Million $)	Cost-Effective-ness ($/$MtCO_2e$)	Level of Support
		2015	2025	Total 2008–2025			
TLU Area 1: Reduce VMT by the sum of the VMT reductions from TLU recommendations 1, 2, 5, 7, 9, and 14.							
TLU-1	Improved Land Use Planning and Development Strategies	0.7	1.9	14.9	Net savings	Net savings	Unanimous
TLU-2	Expand Transit, Bicycle, and Pedestrian Infrastructure	0.1	0.3	3.0	$0	$0	Unanimous
TLU-5	Climate-Friendly Transportation Pricing/Pay as You Drive	1.1	2.1	20.9	–$1	–$1	Super Majority (3 objections)
TLU-7	"Fix-it-First" Transportation Investment Policy and Practice	Not quantified					Super Majority (2 objections)
TLU-9	Workplace Tools To Encourage Carpooling, Bicycling, and Transit Ridership	0.3	0.4	4.5	Large net savings	Large net savings	Unanimous
TLU-14	Freight Mode Shifts: Intermodal and Rail	NA					Super Majority (1 objection)
TLU-1 Total		**2.2**	**4.7**	**43.3**	**N/A**		

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/$MtCO_2e$ = dollars per metric ton of carbon dioxide equivalent; VMT = vehicle miles traveled; N/A = not applicable.

The TLU Area 1 Overall VMT reduction goal is roughly 10.3 billion VMT in 2025, for a 2025 VMT of 56,530,900,000.

TLU Area 2: Reduce carbon per unit of fuel [Cleaner Fuels].

- TLU-3 Low Greenhouse Gas Fuel Standard

TLU-3 would contribute as follows:

Policy No.	Policy Recommendation	GHG Reductions* ($MMtCO_2e$)			Net Present Value 2008–2025 (Million $)	Cost-Effective-ness ($/$MtCO_2e$)	Level of Support
		2015	2025	Total 2008–2025			
TLU Area 2: Reduce carbon per unit of fuel							
TLU-3	Low GHG Fuel Standard (Overlap With AFW-7)	1.7	3.6	36.2	Not quantified		Unanimous

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/$MtCO_2e$ = dollars per metric ton of carbon dioxide equivalent; AFW = Agriculture, Forestry, and Waste Management.

TLU Area 3. Reduce per vehicle energy consumption [Improved Vehicle Efficiency].

- TLU-4 Infrastructure Management
- TLU-5 Climate-Friendly Transportation Pricing [in part]
- TLU-6 Adopt California Clean Car Standards
- TLU-8 Update Road Standards [in part]
- TLU-12 Mobile Source Emissions Reduction
- TLU-13 Reduced Speed Limits

Recommendations in this area give the following reductions:

Policy No.	Policy Recommendation	GHG Reductions* ($MMtCO_2e$)			Net Present Value 2008–2025 (Million $)	Cost-Effective-ness ($/$MtCO_2e$)	Level of Support
		2015	2025	Total 2008–2025			
TLU Area 3: Reduce carbon per mile and/or per hour							
TLU-4	Infrastructure Management	0.04	0.1	0.7	*Not quantified*		Unanimous
TLU-6	Adopt California Clean Car Standards	0.74	1.16	13.1	–$263	–$39	Majority (16 objections)
TLU-12	Voluntary Fleet Emission Reductions	0.4	0.4	6.1	*Not quantified*		Unanimous
TLU-13	Reduce Maximum Speed Limits	0.4	0.4	6.1	N/A	$50 at $2.40/gal $–19 at $3.40/gal	Majority (16 objections)
	Total	**1.58**	**2.06**	**26.0**	**N/A**		

Summary discussion of emission reductions by TLU Area

Context Question: If GHG reductions required by Minnesota law come from the transportation sector in the same percentage as they are generated today, then what is the transportation and land use sector target amount?

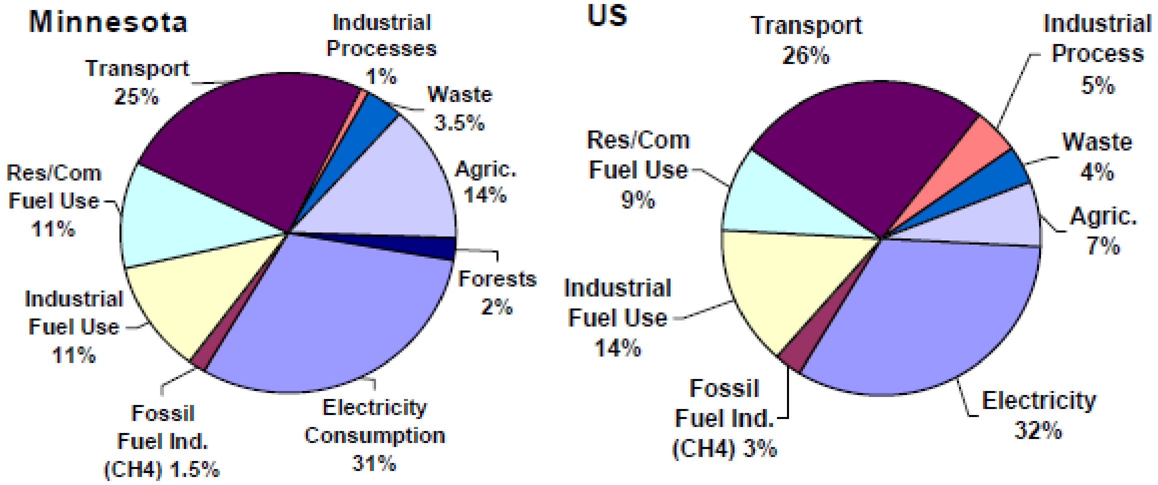
Answer: Keeping in mind that the MCCAG process does not require or assume proportional emission reduction contributions from each sector, the targets are

1. Statewide GHG emission reduction goals of 15% by 2015, 30% by 2025, and 80% by 2050, using 2005 emissions as a benchmark.

2. In 2005, activities in Minnesota accounted for approximately 151 million metric tons of carbon dioxide equivalent ($MMtCO_2e$) emissions.

3. Transportation is 25% of Minnesota emissions, as in Figure H-1.

Figure H-1. Gross GHG emissions by sector, 2000: Minnesota and United States



Thus, proportional reductions from TLU would be:

155.00	MMtCO$_2$e in 2005
–0.45	Biofuels existing actions not accounted for in baseline
154.55	
* 30%	reduction by 2025
46.37	MMtCO$_2$e reduction in 2025
* 25%	Transportation share
11.59	**MMtCO$_2$e reduction from T in 2025**

TLU-1. Improved Land-Use Planning and Development Strategies

Policy Description

This policy improves land use planning and development practices to target growth in ways that reduce the number and length of vehicle trips, thus reducing GHG emissions. (It accounts for part of the VMT reduction goal, along with TLU-2, -5, -7, -9, and -14.)

Policy Design

Goals:

Guide new households into currently developed areas.

Twin Cities Metropolitan Area—Target a higher percentage of new development into "priority growth areas" within 65 cities the Metropolitan Council (MC) classifies as "developed" (e.g., Minneapolis, St. Paul, Burnsville, Coon Rapids, Mendota Heights, Stillwater, and Minnetonka).

- Increase to 60% the percentage of housing targeted to the developed area for 2013–2030 (currently 27%–30% in the MC Development Framework for 2000–2030).
- Increase to 75% the percentage of jobs targeted to the developed area for 2013–2030 (currently 55% in the MC Development Framework for 2000–2030).

Greater Minnesota—Target a significantly higher percentage of new growth in jobs and housing into incorporated cities in locations that can be accessed by bicycling, walking, and public transit.

Timing: To achieve VMT goals, policy implementation should commence as soon as possible.

- Best practices technical assistance to be developed in 2008–2009 and promoted starting in 2010.
- Statewide and regional planning goals to be incorporated in next MC Development Framework and implemented beginning in 2013.

Statewide—Reduce subsidies for low-density, auto-oriented development patterns, and provide incentives and technical assistance to communities to target growth in priority growth areas where walking, bicycling, transit use, and shorter auto trips can reduce VMT.

Parties Involved: All levels of government, including local, county, school district, regional, and state; developers and contractors; employers; homeowners.

Other: None.

Implementation Mechanisms

To achieve these VMT reduction goals, the state, MC, and local communities will need to use some or all of the following strategies that have been used in other states and regions.

1. **Priority Areas Designated for Planned Growth**

   Establish a process to designate types of priority growth areas within the state, such as town centers, downtowns, regional centers, neighborhood centers, transit corridors, transit station areas, and brownfields (old commercial or industrial sites). Establish a process to encourage higher-density housing and employment growth; mixed-use and mixed-income development; and bicycle, pedestrian, and transit-friendly development within these areas. Development would be promoted through incentives, technical assistance, and/or regulation.

2. **School Siting and Accessibility**

   Review and revise school siting laws in Minnesota to remove excessive acreage requirements that drive schools into undeveloped areas. Encourage the development or rehabilitation of schools in priority growth areas, to make it easier for children, teachers, and parents to get to school on foot, bicycle, and transit.

3. **Jobs–Housing Balance**

   Plan and zone for new housing development to be near existing jobs, and plan and zone for new commercial development near existing housing. Implement financial incentives and/or regulation to encourage a range of housing types and affordability levels that support a community's local work force, which will create a stronger jobs/housing balance and reduce the length and number of vehicle trips.

4. **Smart-Growth Planning, Modeling, and Tools**

   Institute statewide and municipal planning requirements and/or incentives to implement TLU-1. Continue planning requirements in the Twin Cities metropolitan area, require state planning to implement TLU-1, and support planning for municipalities throughout greater Minnesota.

   Provide technical assistance to communities on best practices in zoning, parking, and street design to increase walking, bicycling, and transit use; to encourage higher-density, transit- and walking-oriented development; and to balance regional residential, commercial, and industrial needs. An example of this type of effort is Oregon's Transportation and Growth Management technical assistance program, accessible at: http://www.lcd.state.or.us/LCD/TGM/index.shtml

   Create an integrated transportation and land-use forecasting model for use statewide. This tool would enable communities to predict increased VMT and GHG emissions based on proposed developments.

   Create a development cabinet, or other government oversight group, that guides state investments to reduce VMT and GHG emissions.

5. **Targeted Open Space Protection**

   Establish programs and/or requirements to preserve key forestland, natural areas, agricultural land, and parkland, which will help to guide development and redevelopment into targeted growth areas.

6. **Transportation Investments**

   Transit- and Pedestrian-Oriented Development—Plan for and invest in transit- and pedestrian-oriented corridors that will draw and support higher-density, mixed-use development along bus corridors and at rail stations.

   Complete Streets and Well-Connected Streets—Develop statewide guidance and technical support for Complete Streets and Well-Connected Streets to shorten trip distances, to make walking and walking to transit safer and more convenient, to reduce the need for large urban arterial roads, and to support higher-density development.

7. **Funding**

   Target new and existing transportation and housing dollars from regional, state, and federal sources to projects that help meet these land-use and development goals.

Related Policies/Programs in Place

- Metropolitan Livable Communities Program Tax Base Revitalization Account (TBRA) grants have funded projects in the metropolitan area to clean up polluted land and buildings for redevelopment, create new jobs and affordable housing, and direct growth to central cities and older suburbs. TBRA grant awards totaling $64.84 million were awarded from budgeted funds during the period 1996–2006. Those funds will leverage an expected $3.4 billion in private investment.
- MC provides Livable Communities Demonstration Account (LCDA) grants to metropolitan area communities for projects that result in connected development patterns that link housing, jobs, and services and use regional infrastructure efficiently. LCDA grant awards totaling $74.67 million were awarded from budgeted funds during 1996–2006. MC expects those funds to leverage more than $2.77 billion in private development investment.
- Minnesota Housing has a priority for housing development located near regional and interregional transportation corridors and transitways, in proximity to existing development and services. Minnesota Housing also supports new development that is not located near wetlands, steep slopes, critical habitat, or on prime farmland or parkland.
- Some counties have sold bonds to protect open spaces. MC plans to increase the regional park and open-space system from 53,000 acres to 70,000 acres. The parks plan calls for three new parks by 2030 and for four new regional parks to complete the system, post-2030.

Type(s) of GHG Reductions

Primarily CO_2.

Estimated GHG Reductions and Net Costs or Cost Savings

GHG Impacts

This policy option is part of the group of options that will contribute to fulfilling the broad VMT reduction goal. The TLU TWG assumes that

1. TLU-1 produces land-use changes that approximate the impacts modeled in Blueprint 2030 for the Twin Cities region (while noting that the recommendations here are not for a

return to Blueprint 2030 *per se*). Modeling for Blueprint 2030 forecast an approximately 12% region-wide decrease in VMT from the baseline.[1]

2. Those reductions are accomplished in urban areas of the state, not just the Twin Cities region. While the numeric goals above are for the Twin Cities region, the implementation mechanisms also apply to greater Minnesota, and will be especially effective in the urban areas of greater Minnesota.

The Twin Cities baseline VMT is 29,233,300,775. Total 2025 VMT in Minnesota urban areas is forecasted to be 42,028,452,537.

A 12% decrease from the latter figure is a reduction of 5,043,414,304 VMT in 2025. That is 6.0% of *all* VMT, which is then converted to CO_2 for use in the reductions table.

Costs/Cost Savings
All else being equal, buildings cost somewhat more to construct in urban areas than in suburban or exurban areas. The preponderance of the evidence, and of the academic review of that evidence, finds that increased private construction costs are more than paid for (1) through initial higher sales prices, and higher resale value over time, and (2) through substantial savings in reduced infrastructure costs.

Under a compact, transit-oriented development scenario, such as would be produced under this option, the Twin Cities metropolitan area would save $3 billion in infrastructure costs over 20 years.[2] A portion of those benefits would come from the transit use that improved land-use patterns would make possible. More compact land use alone would produce net cost savings, as the more compact development pattern by itself would save substantial portions of the $3 billion estimated by MC. A wide variety of literature supports MC's finding: integrated transportation and land-use planning produces net savings on total costs of buildings + land + infrastructure + transportation. Some portions of that total cost may be higher. The preponderance of literature suggests net savings overall.[3] A National Academy of Sciences/Transportation Research Board review found substantial regional and state-level infrastructure cost savings from more compact development, as shown in Table H-1.

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[1] Keith Bartholomew (2005), Integrating Land Use Issues into Transportation Planning: Scenario Planning Summary Report, College of Architecture + Planning, University of Utah. Blueprint 2030 was developed by the Metropolitan Council and adopted by it on December 18, 2002. The subsequent Metropolitan Council replaced Blueprint 2030 with the 2030 Regional Development Framework.

[2] Metropolitan Council, Blueprint 2030, Appendix E, page 9.

[3] Literature reviews include US EPA (2001), "Our Built and Natural Environments: A Technical Review of the Interactions Between Land Use, Transportation, and Environmental Quality"; and Burchell et al. in footnote 8.

Table H-1. Burchell findings of savings of compact growth versus trend development[4]

Area of Impact	Lexington, KY, and Delaware Estuary	Michigan	South Carolina	New Jersey
Public–private capital and operating costs				
Infrastructure roads (local)	14.8%–19.7%	12.4%	12%	26%
Utilities (water/sewer)	6.7%–8.2%	13.7%	13%	8%
Housing costs	2.5%–8.4%	6.8%	7%	6%
Cost-revenue impacts	6.9%	3.5%	5%	2%
Land/natural habitat preservation				
Developable land	20.5%–24.2%	15.5%	15%	6%
Agricultural land	18%–29%	17.4%	18%	39%
Frail land	20%–27%	20.9%	22%	17%

Data Sources:

Fuel use: Minnesota Inventory and Forecast.

VMT forecasts: Federal Highway Administration, available at: http://www.fhwa.dot.gov/ohim/hs92/roads.pdf, MC Transportation Planning.

VMT reductions: MC, Blueprint 2030.

Quantification Methods:

As above. In addition to the modeling done for Blueprint 2030, a wide variety of literature finds that integrated transportation and land-use planning can substantially reduce VMT and its attendant emissions.[5] Because the Blueprint 2030 modeling did not use the most advanced available techniques to capture the VMT impacts of the modeled policies, the reductions estimates used here are likely to be conservative.[6]

Key Uncertainties

Vehicle miles traveled since 1990 have increased statewide by 45%. This is one of the fastest growth rates in the nation, far outpacing the state population growth of 19% in the same time period. The regions outside the Seven-County Metro area are responsible for much of the immense increase in VMT.

Reducing the number of miles that a vehicle travels through more strategic land-use planning and development is a policy approach that works primarily in urban areas where jobs and commercial services are more likely to be closer to residential growth areas. While the metro area held 52% of the state population in 1990, it produced only 45% of the annual state VMT. In 2005, the metro area had 54% of the statewide population and 40% of the state VMT. By 2025, the

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[4] Robert Burchell, et al., *The Costs of Sprawl—Revisited (TCRP Report 39)*, Transportation Research Board/National Research Council/National Academy Press, Washington, DC, 1998.

[5] U.S. Environmental Protection Agency, *Our Built and Natural Environments: A Technical Review of the Interactions Between Land Use, Transportation, and Environmental Quality*, 2001. http://www.epa.gov/dced/built.htm

[6] Bartholomew, footnote 2, above.

percentages will continue to diverge to 58% of the statewide population in the metro area, yet only 36% of the state VMT. Per capita VMT is expected to grow very little in the metro area by 2025, yet it is projected to increase dramatically statewide.

Reducing the number of miles traveled is a crucial component to reducing harmful GHG emissions, even with increased clean fuel and efficiency. The burden of reducing the number and lengths of trips taken will be concentrated on the seven-county metropolitan area and the population growth centers in greater Minnesota, and should be considered when recommending policies. Whether Minnesota strives to achieve the number of annual VMT overall or based on per capita as the state did in 1990, policies for reducing the number and length of travel trips will be targeted to the metro area and greater Minnesota growth centers.

How to manage VMT statewide needs more analysis and is a key uncertainty to pursue.

Additional Benefits and Costs

1. Makes transit service more feasible and cost-effective (need a minimum of 8 residential units per acre for minimum-level bus service, 15 units per acre for frequent bus service, and 30 units per acre for rail service).
2. Improves public health by making it easier and safer for people to walk.
3. Reduces the number and severity of vehicle crashes by reducing the number of high-speed, high-traffic arterial streets and by making walking and bicycling safer.
4. Supports social interaction with more people walking, bicycling, and riding public transit.
5. Reduces air pollution. Blueprint 2030 forecasted a 50% decrease in nitrogen oxide (NO_x) emissions in 2030 relative to the baseline.
6. Reduces urban land consumption, keeping Minnesota land in agriculture and open space. Blueprint 2030 forecasted a 35% decrease in land consumption relative to the baseline.

Personal Risk

There are divergent views about the change in personal risk that accompanies more compact development. Many people believe that personal danger/risk from criminal activity is greater in higher-density living and in the inner city and first-ring suburbs, and give this reason for new development farther from core cities. The contrary view argues that the concern about personal safety and more dense forms of development is often based on perceptions of failed public housing efforts of the past that geographically isolated low-income households in high-rise residential developments.

However, new, more compact, mixed-use, and mixed-income forms of development in central cities and developed suburbs have established some of the most attractive and livable neighborhoods in other regions. Market research by the National Association of Realtors shows that more and more buyers prefer living in neighborhoods that are more compact and offer more activities and less need to drive, and that those preferences are reflected in market premiums. These new forms of compact development provide more personal safety because they put “eyes on the street” and give all residents a sense of ownership in the public spaces.

The annual cost to government to establish planning programs, to provide new planning tools, to review current funding and reposition funding criteria to encourage growth in priority areas, and to provide technical assistance could be $10–$20 million.

Feasibility Issues

The TLU TWG members raised two general feasibility questions:

- Are the goals numbers achievable, given existing development patterns, market patterns, and investment trends?
- Have the implementation mechanisms included enough tools to allow communities to reach these goals?

MC believes that the goals in its current Development Framework are at the edge of likely feasibility.

Status of Group Approval

Approved

Level of Group Support

Unanimous

Barriers to Consensus

None

TLU-2. Expand Transit, Bicycle, and Pedestrian Infrastructure

Policy Description

This strategy expands infrastructure and programs to increase transit ridership, carpooling, bicycling, and walking. It will reduce GHG emissions by reducing VMT (fewer vehicle trips and shorter trip distances). (It accounts for part of the VMT reduction goal, along with TLU-1, -5, -7, -9, and -14.)

Policy Design

Goals:

- Implement MC's transit plan to double transit ridership by 2020 (from 75 million rides annually to 150 million), 10 years sooner than the current target date of 2030. The plan calls for investment in light rail, commuter rail, bus rapid transit, and expanded bus service.
- Improve and expand transit (rail and bus) service between regional centers in greater Minnesota and the Twin Cities region, including Rochester, Marshall, Moorhead, Winona, Bemidji, Duluth, Detroit Lakes, Mankato, Grand Rapids, East Grand Forks, and other regional centers. Provide and ensure adequate service between these communities and the Twin Cities region (specifically, the Minneapolis St. Paul airport, downtown Minneapolis, and downtown St. Paul).
- Increase bike and pedestrian infrastructure in cities across Minnesota, including sidewalks, trails, bike lanes, and other amenities that make walking and bicycling safer and more convenient.

Timing: Begin implementation by 2008 and complete implementation by 2020.

Parties Involved: State legislature, MC, MnDOT, Metropolitan Transitways Development Board, counties, cities, freight rail, private sector businesses.

Other: None cited.

Implementation Mechanisms

1. **Expand Transit Service**

- The MC transit plan calls for adding light rail, commuter rail, and dedicated busways and increasing regular route bus service by 80% (more routes and more frequent service). This expansion would also include additional marketing, promotion, and pricing incentives (including tax incentives for nonprofit organizations).
- Expand transit service between greater Minnesota and the Twin Cities metropolitan area via intercity bus and Amtrak.

2. Expand Bike and Pedestrian Infrastructure

- Support walk and bike access to destinations and to transit by adding and improving sidewalks, trails, bike lanes, and other amenities (e.g., lighting, landscaping, bike parking, and lockers).

Related Policies/Programs in Place

Recent Actions in Minnesota:

- The MC Transportation Advisory Board programmed $95.6 million in Transportation Enhancement and Surface Transportation Program funds between 1992 and 2005 for public transit, bicycling, and walking, of total state and federal funding. Transit for Livable Communities is implementing a 4-year, $25 million federal pilot program to increase rates of bicycling and walking targeted to Minneapolis.
- In 2006, Minnesota voters approved a constitutional amendment requiring dedication of motor vehicle sales tax funds to transit, which will result in increased finding.
- The Twin Cities region has two high-occupancy vehicle (HOV) lanes (I-394 and I-35W). I-394 is a high-occupancy toll (HOT) lane that allows single-occupant vehicles to use the HOV lane for a fee. A memorandum of understanding between MC and MnDOT provides for consideration of additional HOT lanes in future highway improvements.

Type(s) of GHG Reductions

Primarily CO_2.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources:

Average length of transit trip: Federal Transit Administration.

Quantification Methods:

GHG Reductions

Transit:

- 75,000,000 new transit rides × 6.71 miles per 7-county transit trip.[7]
- 13-county transit averages 8.53 miles/trip. The TLU TWG used just 7-county transit averages to be conservative.
- Total VMT reduced in 2025: 503,250,000, or 1.27% of all light-duty VMT statewide.
- Assumed that transit growth from this policy started in 2008, grew smoothly to the 2025 VMT reduction level, and then converted to CO_2.

Bike and Pedestrian:

- The policy option does not include specific goals for new bike and pedestrian spending or activity. Substantial literature documents the positive response of bike and pedestrian

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[7] See http://www.metrocouncil.org/planning/transportation/TBI_2000/TravelTimeTripLength_7County.pdf

activity to improved infrastructure.[8] However, without a new infrastructure target in this policy option, it is difficult to quantify the likely impacts of this policy.

Costs
The additional cost to implement the MC transit plan on an accelerated time frame is estimated to be $210 million per year for 13 years, or nearly $3 billion.

Savings
A report prepared in 2002 by an MC consultant hired to study regional growth development options showed a $3 billion savings in infrastructure costs over 20 years under a compact development scenario focused to some degree along pubic transit routes for the Twin Cities metropolitan area. (Blueprint 2030 Appendixes, item E, page 9.)

The ~$3 billion cost minus ~$3 billion infrastructure savings = a net cost of $0. That zero net cost does not include a variety of other savings. For example, reducing VMT and increasing reliance on public transit will result in a reduced parking demand, lower household costs for transportation, decreased traffic congestion, improved air quality, reduced need and cost for roadway expansion, and improved health for new transit riders who walk or bicycle to transit.

The University of Minnesota's *Full Costs of Transportation in the Twin Cities Region* report concluded that the total cost of a mile of auto travel in the region was between $0.84 and $1.62, with a mid-range estimate of $1.14. With the costs of the transit accounted for above, these are net savings:

503,250,000 VMT × $1.14/mile = $573,705,000

A wide variety of empirical experience suggests that the transit investments in this option will produce substantial additional benefits/net savings, as in the following examples.

- *Transit investments generally*—Nationally, transit produces net economic returns on investment: "For every $10 million invested, over $15 million is saved in transportation costs to both highway and transit users. These costs include operating costs, fuel costs, and congestion costs." These are in addition to the ancillary benefits summarized below.[9]
- *Transit fare initiatives*—Unlimited Access transit at the University of California–Los Angeles costs $810,000 a year and has total benefits of $3,250,000 a year.[10] Similar programs at other universities show similar results.[11] Universities are in some senses unique institutions, but the general types of challenges (especially demand for and cost of providing

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[8] For example, Jennifer Dill and Theresa Carr (2002), *Bicycle Commuting and Facilities in Major U.S. Cities: If You Build Them, Commuters Will Use Them—Another Look*, Portland State University, Portland, Oregon, available at: http://www.des.ucdavis.edu/faculty/handy/ESP178/Dill_bike_facilities.pdf. "Study confirms findings that cities with higher levels of bicycle infrastructure also have higher levels of bicycle commuting."

[9] Cambridge Systematics, Inc., *Public Transportation and the Nation's Economy: A Quantitative Analysis of Public Transportation's Economic Impact*, 1999, available at: www.apta.com/research/info/online/documents/vary.pdf

[10] Jeffrey Brown, Daniel Hess, and Donald Shoup, "Fare-Free Public Transit at Universities: An Evaluation," *Journal of Planning Education and Research* 23:69–82, 2003.

[11] Jeffrey Brown, Daniel Hess, and Donald Shoup, "Unlimited Access," *Transportation* 28:233–267, Kluwer, 2001.

parking), and the types of benefits enjoyed in response to commute benefits programs, are equally available to businesses, even businesses located in what would normally be thought of as locations unsupportive of transit use:

> "Eco Passes also offer significant advantages for employers who offer free parking to all commuters, because those who shift from driving to transit will reduce the demand for employer-paid parking spaces. A survey of Silicon Valley commuters whose employers offer Eco Passes found that the solo-driver share fell from 76 percent before the passes were offered to 60 percent afterward. The transit mode share for commuting increased from 11 percent to 27 percent. These mode shifts reduced commuter parking demand by approximately 19 percent.
>
> "Given the high cost of constructing parking spaces in the Silicon Valley, each $1 per year spent to buy Eco Passes can save between $23 and $333 on the capital cost of required parking spaces."[12]

- *Transit and non-SOV options information and promotion*—Per public dollar, a Minnesota Transportation Management Organization (TMO) can accommodate seven times as many commuters as new highway investment.[13]

Key Assumptions: Above.

Key Uncertainties

None cited.

Additional Benefits and Costs

[The benefits of decreases in criteria air emissions will be analyzed at a later date.]

Feasibility Issues

None cited.

Status of Group Approval

Approved

Level of Group Support

Unanimous

Barriers to Consensus

None

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[12] Ibid., 260.

[13] Minnesota Department of Transportation, Modal Options Identify Project, "Measurement and Evaluation," 2006.

TLU-3. Low-GHG Fuel Standard

Policy Description

The State of Minnesota would adopt a low-GHG fuel standard (LGFS) and create a market-based program to reduce the GHG emissions from transportation fuels and diversify transport fuel options for consumers. The LGFS would be designed to require fuel providers to reduce the GHG intensity of the fuels they sell in Minnesota. Fuel providers are identified as producers, importers, refiners, and blenders. The GHG intensity is specified as a CO_2 equivalent[14] per British thermal unit. The LGFS would not be designed to encourage the use of any particular fuel. Instead, it would include fossil and renewable fuels.[15]

The LGFS is not a tailpipe standard for GHGs, as it considers GHG emissions on a full-fuel-life-cycle basis, which includes not only tailpipe emissions, but also emissions associated with the production and distribution of fuels. This will result in varying carbon impact values for fuels that would ostensibly be the same to customers.[16]

Policy Design

Goals: Adopt a state law requiring the average carbon intensity of on-road transportation fuel to be reduced by 10% by 2020 and by 12% by 2025 from 2007 levels. (Note that California's low-carbon fuel standard (LCFS) requires a 10% reduction by 2020.) Other policies seek to reduce consumption of motor fuels, while this approach changes the fuel mix to reduce GHGs.[17]

Timing: As noted above.

Parties Involved: All levels of government and fuel providers.

Implementation Mechanisms

- Partnership with the University of Minnesota and the MnDOT to create the framework for the LGFS.
- Market-based mechanisms for fuel providers to choose how they wish to meet the LGFS.

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[14] Each GHG has a global warming potential (GWP) that allows it to be expressed in terms of CO_2. This notation is referred to as carbon dioxide equivalent (CO_2e). For example, methane (CH_4) has a GWP of 23. Therefore, 1 metric ton (Mt) of CH_4 can be expressed as 23 $MtCO_2e$.

[15] Alternative fuels are defined in the Energy Policy Act of 1992 and include biodiesel, electricity, ethanol, hydrogen, natural gas, and propane.

[16] For example, E10, in which the ethanol is derived from cellulose, has the potential to reduce the full-fuel-life-cycle carbon impact compared with E10 in which the ethanol is derived from corn. How the ethanol is made affects its life-cycle GHG profile, and not all corn ethanol is exactly the same. Cellulosic E10, while potentially better in its GHG profile than sugar-based (corn) ethanol, will also vary depending on feedstock(s) and thermal heat input source(s).

[17] Note that the goal is to reduce the average carbon intensity of a gallon of fuel, not the carbon content of the full fuel stream.

- Full-fuel-life-cycle basis of measuring GHG impact of transportation fuels. Implemented by a cap-and-trade system for fuel providers.
- Financial incentives for refueling station creation and retrofitting based on the LGFS, and possibly for other institutions helping substitute low-GHG-fuels for high. For example, truck-stop electrification may substitute low-GHG fuel and fuel use for high.
- Certification process.

Related Policies/Programs in Place

Recent Actions in Minnesota:

- The current state policy for fossil diesel displacement is 2% biodiesel blend. For gasoline displacement, the current policy goal is 20% ethanol displacement by 2013, with a carve-out goal for 5% derived from cellulosic material. The current petroleum displacement goal is for 20% of the liquid fuel sold in the state to come from renewable sources by 2015, and 25% by 2025.
- Metro Mobility uses the highest level of biofuel allowable by operating conditions and vehicle manufacturers.
- Metro Transit, which uses B5 (5% biodiesel), is testing B20 (20% biodiesel). Metro Transit is considering using B10 (10% biodiesel) by mid-2007, pending B20 test results. The agency is also looking for other engine technology that uses other types of renewable fuels.
- Formation of the NextGen Energy Board to determine how the state can invest most efficiently to achieve energy independence—$90 million from 2010 to 2020.
- Ethanol: Minnesota established an ethanol production incentive to pay producers to help develop a new market for Minnesota’s agricultural products. On the market side, Minnesota requires that all gasoline sold in the state be blended with a 10% ethanol mix. In addition, Minnesota began efforts in 1997 to develop a network of fueling stations for flex-fuel vehicles that could run on an 85% ethanol blend. Today Minnesota has over 300 E85 fueling stations around the state that together sold 18,160,000 gallons of E85 blended gasoline during 2006. See http://www.pca.state.mn.us/programs/ethanol.html and http://www.pca.state.mn.us/programs/ethanol.html#links
- Biodiesel: According the U.S. Department of Energy (DOE), biodiesel has the most favorable energy balance of any transportation fuel. For every unit of energy needed to produce a gallon of biodiesel, 3.2 units of energy are gained. As of September 29, 2005, Minnesota requires nearly all diesel fuel sold in the state to contain at least a 2% biodiesel blend. It is estimated that this requirement will replace 16 million gallons of diesel fuel in the state (Minn. Stat. §239.77).
- Electricity: According to recent information provided by the Minnesota Pollution Control Agency (MPCA), electricity as used in a hybrid gas/electric vehicle is a very low-GHG fuel source. Compared with conventional gasoline and reformulated gasoline, electric/gas hybrids show a 37.2% reduction in GHG emissions in grams per mile. This is compared with a 1.5% reduction for E10, a 15.6% reduction for E85 flex fuel, and a 25.5% reduction for conventional and low-sulfur diesel.

Recognizing the potential benefits of hybrids, plug-in hybrids, and electric vehicles for reducing GHG emissions, Minnesota has taken a number of steps to encourage their development, including an appropriation of over $2 million for the 2008–2009 biennium for studying and testing plug-in hybrid electric vehicles.

Type(s) of GHG Reductions

All GHG types in the fuel life cycle.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources:

David Crane and Brian Prusnek, "The Role of a Low Carbon Fuel Standard in Reducing Greenhouse Gas Emissions and Protecting Our Economy," California Air Resources Board, January 8, 2007.

Quantification Methods:

Because the LGFS would mandate a 10% decrease in carbon content, the high-level analysis is relatively straightforward: a straight 10% decrease in the baseline on-road carbon emissions in 2020.

The LGFS would take into account the full fuel cycle when calculating that carbon content. Because the current Inventory and Forecast is not on a full fuel cycle basis, that analysis is not done here either.

Key Assumptions:

That fuels technologies advance sufficiently to allow these goals to be met. Research by the University of California on the achievability of the California LCFS finds:

> "On the basis of a study of a wide range of vehicle fuel options, we find a 10 percent reduction in the carbon intensity of transportation fuels by 2020 to be an ambitious but attainable target. With some vehicle and fuel combinations, a reduction of 15 percent may be possible."[18]

Different full-fuel-cycle analysis ("well-to-wheels" or "field-to-wheels") methods show different total carbon amounts per gallon for the same fuel pathway. For example, different models show different results for ethanol using corn as a feedstock, and distilled ethanol with a given energy source (e.g., electricity from coal, on-site natural gas). Adopting this policy will require the state to establish an official analytical method that distinguishes between the carbon impacts of two fuels that are essentially the same at the pump, yet have very different production origins. Figure H-2 illustrates one analysis of the potential range of carbon impacts from ethanol. The chart is included here *not* to establish recommended or likely impacts from different methods of ethanol production, but simply to illustrate the potential range of impacts from a single fuel type using a given analytical method, which can range from an increase in emissions relative to gasoline, to a significant decrease. A well-specified LGFS would account for these differences.

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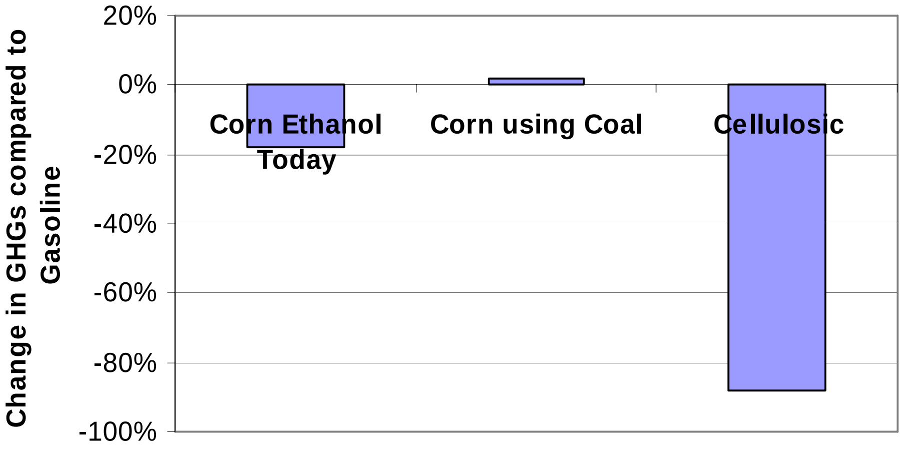
[18] Alexander E. Farrell, Daniel Sperling, et al. A Low-Carbon Fuel Standard for California, Part 1: Technical Analysis, May 29, 2007. Executive Summary, p. 8. Available at: www.its.berkeley.edu/sustainabilitycenter, www.its.ucdavis.edu, and http://www.arb.ca.gov/fuels/lcfs/lcfs.htm

Figure H-2. Low-carbon fuel standard necessary to ensure GHG reductions from the use of biofuels



Source: Farrell, et al., “Ethanol Can Contribute to Energy and Environmental Goals,” *Science* 27 January 2006: Vol. 311. no. 5760, pp. 506 - 508.

Table H-2 shows a similar range of potential reductions.

Table H-2. Estimated biofuel impacts on GHG emissions

Fuel/Technology	Blend	Feedstock	Reduction (grams of GHGs per mile)*	Normalized Reduction (100% blend)
Ethanol	E10	Corn	1.5%	15.0%
Ethanol	E10	Cellulosic	7.2%	72.0%
Ethanol	E85	Corn	17.6%	20.7%
Ethanol	E85	Cellulosic	83.2%	97.9%
Biodiesel	B20	Soy	9.9%	49.5%
Biodiesel	B20	Canola	11.2%	56.0%
Biodiesel	B20	Palm	12.0%	59.9%
Biodiesel	B100	Soy	53.9%	53.9%

*Ethanol reductions estimated relative to gasoline; biodiesel reductions estimated relative to diesel fuel. Actual reductions depend on many factors in the production, distribution, and use of fuels.

Sources: GREET v1.7 outputs; (S&T)^2 Consultants, *Sensitivity Analysis of GHG Emissions From Biofuels in Canada,* 2006.

Cost

The TWG reviewed various approaches to potential costs of this scenario and agreed that, in absence of specific regulatory proposal and given fluid nature of technology, it is not possible to develop a useful cost number. California’s materials developing its LCFS have specifically not estimated the likely costs of an LCFS.

Note that some reductions will come from future fossil fuel refinery efficiencies.

Key Uncertainties

LGFS could have a significant impact on Minnesota, in that E10, the current maximum ethanol blend percentage for non–flex-fuel vehicles, is the state mandated standard for all gasoline blends.

See extensive analysis and discussion by the California Environmental Protection Agency Air Resources Board (CARB) and related research by the University of California, Davis. Those studies review the technical challenges and uncertainties facing this type of policy. (See Alexander E. Farrell et al. A Low-Carbon Fuel Standard for California. Part 1: Technical Analysis, May 29, 2007. Part 2: Policy Analysis, August 1, 2007; available at: http://www.arb.ca.gov/fuels/lcfs/lcfs.htm. Specifically, see the assumptions about the cradle-to-grave performance of cellulosic ethanol, especially transporting the cellulosic materials to create cellulosic ethanol, and whether it will really dramatically reduce GHG emissions, considering there's no current transportation and distribution network for cellulosic materials like there is for corn.

Additional Benefits and Costs

Benefits:

- Additional farm income, with attendant benefits for rural families and communities.
- Improved urban health and air quality.
- Potential for market innovation in new technologies for both refiners and clean energy providers.

Costs:

- *Environmental*: There is extensive debate about the non-emission environmental impacts of biofuel production. In Minnesota, demand for additional biofuels would have substantial effect on demand for water and acreage, with subsequent impacts on water supplies and marginal and/or Conservation Reserve Program acreage. There is also extensive debate over the environmental impacts of a move to grass-based fuel feedstocks. Research at the University of Minnesota suggests that a return to harvestable prairie-type ecosystem, for example, would not support extensive prairie-like biodiversity.

  Those debates are too extensive to summarize here, other than to conclude that an LGFS would almost certainly increase the demand for Minnesota-based biofuels to some extent, and that increased demand would most likely have some negative environmental impact. Until the economics of an LGFS are clearer, it is not possible to forecast the extent to which an LGFS would produce additional demand for Minnesota-based biofuels, versus other types of fossil (natural gas) or renewable (wind, hydro) fuelstocks, or the resulting impacts.

- *Economic*: Minnesota farmers are realizing that higher grain prices are not necessarily beneficial, because they raise input prices for a range of other farm products.

Feasibility Issues

See Key Uncertainties, above.

Status of Group Approval

Approved

Level of Group Support

Unanimous

Barriers to Consensus

None

TLU-4. Infrastructure Management

Policy Description

With the state as a coordinator, this strategy will build on current efforts to create a seamless multimodal system to serve all transportation modes, improve traffic flow, and decrease vehicle idling and congestion (where it will not negatively affect bicycling and walking or induce additional vehicle trips). This strategy will also reduce carbon emissions by reducing the number and length of motor vehicle trips; increasing walking, bicycling, and transit use; and supporting development patterns that use these modes.

Policy Design

1. **Manage to reduce congestion.**

   State, regional, and local transportation agencies will make investments to

   - Synchronize traffic signals to improve traffic flow;
   - Provide priority signaling for buses on key transit corridors;
   - Improve incident management (vehicle crashes and breakdowns);
   - Provide real-time information for commuters about congestion, transit, and parking;
   - Install roundabouts where appropriate;
   - Test state-of-the-art parking strategies; and
   - Convert HOV or general lanes to HOT lanes with “profits” to transit alternatives.

2. **Manage to accommodate all modes.**

   State, regional, and local transportation agencies will change rules and policies to ensure that the needs of all users are taken into account in the design of new and rebuilt roads.

- Adopt a “Complete Streets” policy in Minnesota for all new and reconstructed roads. Ensure, through an inclusive process, that roads are designed to better serve all users, including vehicle drivers, transit users, pedestrians, freight and truck traffic, and bicyclists. (Exceptions can be made for rural roads between communities and so on.) Develop and apply an Urban Preservation Route street classification, similar to the Natural Preservation Route that exists today.
- Require and provide technical assistance to cities and counties to develop bicycle and pedestrian plans to identify local needs and priorities.
- Develop policies and guidelines for municipalities regarding street connectivity.

Goals: Use infrastructure management to reduce urban-area transportation emissions by 0.5% by 2025 relative to 2005.

Timing: 2008–2009 adoption, and then ongoing implementation.

Parties Involved: State legislature; all state, regional, and local agencies that deal with transportation; local elected officials; bike, transit, and pedestrian interests; Minnesota Trucking Association, others.

Other: None cited.

Implementation Mechanisms

The annual direct cost to government for strategies under Policy Design 1 could be $10–$30 million. The cost for strategies under Policy Design 2 could be $5 million per year.

Related Policies/Programs in Place

Using Congestion Mitigation and Air Quality Improvement Program (CMAQ) funds, Minneapolis has implemented computerized traffic signals for better traffic flow. The 2007 CMAQ solicitation contains a funding program for traffic signal management and for a freeway on-ramp metering program.

Type(s) of GHG Reductions

Primarily CO_2.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources: Minnesota Inventory and Forecast.

Quantification Methods:

Infrastructure management can reduce emissions both by reducing VMT, and by reducing inefficient operation of the travel network—transit, auto, and truck. To recognize that infrastructure management can reduce emissions in several ways, the goal for this option is expressed in emission reductions. Proportional reductions are taken from total urban emissions, starting in 2008, and ramping up smoothly to 0.5% in 2025.

Key Assumptions:

The multimodal/Complete Streets portion of this option will have mode shift benefits, but these are likely captured in TLU-2.

Policy No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$)			Net Present Value 2008–2025 (Million $)	Cost-Effectiveness ($/MtCO_2e$)	Level of Support
		2015	2025	Total 2008–2025			
TLU-4	Infrastructure Management	0.04	0.1	0.7	*Not quantified*		UC

Key Uncertainties

None cited.

Additional Benefits and Costs

Strategies that reduce congestion can result in significant economic benefits to the state. Some strategies that improve highway system efficiency have safety benefits (reduce vehicle crashes). In addition, strategies that reduce vehicle idling or stop-and-go traffic patterns will reduce emissions of criteria air pollutants (such as particulate matter), resulting in public health benefits.

Feasibility Issues

None cited.

Status of Group Approval

Approved

Level of Group Support

Unanimous

Barriers to Consensus

None

TLU-5. Climate-Friendly Transportation Pricing

Policy Description

This policy recommends that the State of Minnesota institute requirements and policies ensuring that drivers more fully pay the total costs of driving. This policy would encourage drivers to choose transportation alternatives, purchase more efficient vehicles, drive less, and/or drive more efficiently (combining trips). This option generally reduces VMT and GHG emissions. (This strategy accounts for part of the VMT reduction goal, along with TLU-1, -5, -7, -9, and -14.)

Policy Design

The University of Minnesota's *Full Costs of Transportation in the Twin Cities Region* report concluded that the total cost of a mile of automobile travel in the region was between $0.84 and $1.62, with a mid-range estimate of $1.14.[19] Drivers do not see all of those costs, for three general reasons:

1. A substantial portion of the costs is not variable, meaning that driving less does not save the person money. A good example of this is insurance, paid every 3 or 6 months. One goal of this policy is to increase the proportion of that cost that drivers and society can save by driving less.

2. A substantial portion is paid for by revenue streams that are not necessarily directly related to automobile use. For example, property taxes pay for a large portion of the costs of local roads. That nexus may be appropriate for various reasons, but one result is that the cost of vehicle mobility (of all kinds) is not borne by those vehicles.

3. Driving (of all kinds) produces substantial externalities, both positive and negative. Drivers do not see all of them. The impacts of the emitted CO_2 are the externality most central to the MCCAG process.

As a result, this set of policies recommends that Minnesota take action in four areas:

1. Implement a system to encourage the purchase and operation of low-GHG-emitting passenger vehicles.

2. Provide an incentive for auto insurance companies to institute a "pay-as-you-drive" (PAYD) system for policyholders.

3. Implement policies and strategies that make more of the fixed costs of driving into variable costs related to VMT and emissions. Possibilities include CO_2-based registration fees, a VMT tax, congestion pricing, and a fuel tax.

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[19] David Anderson and Gerard McCullough, *The Full Cost of Transportation in the Twin Cities Region*," TRG Report No. 5, Center for Transportation Studies, University of Minnesota, August 2000, available at: http://www.cts.umn.edu/trg/research/reports/TRG_05.html

4. Use new revenue streams for less GHG-intensive travel options (e.g., public transit, vanpooling, commuter benefits, and commuter options).

In all cases, the state should design and implement policies with an explicit consideration of equity impacts on both low-income and rural drivers.

Goals: For PAYD insurance, assume market penetration of 25% in 2015 and 50% in 2025.

Timing: Passage of a comprehensive transportation funding package with some or all of these strategies during the 2008 legislative session, effective July 1, 2008.

Parties involved: Highway and transit users; automobile manufacturers and retailers; insurance companies, Minnesota state Departments of Commerce, Public Safety, Revenue, Finance, and Pollution Control; MC, MnDOT.

Other:

1. Increasing the price of driving reduces the number of miles driven and can be accomplished in a variety of ways. Among the possible strategies is increasing the gas tax, which is likely to both reduce the number of miles driven and provide additional transportation revenue to the state. The TWG discussed various issues raised by a gas tax increase, including the economic and personal impact of higher taxes and the constitutional issues that exist around the use of gas tax revenues. In light of these issues and concerns expressed by the current administration, the TWG is making no recommendation on the gas tax to the MCCAG. However, the group believes the MCCAG should seriously consider financial strategies that would make the full (including environmental) cost of driving more apparent to drivers.

2. Significant policy innovation and development are occurring in this area. In the future, additional options may exist that would accomplish the goals of reducing VMT and providing additional revenues to support lower GHG transportation options, including transit. The fact that these ideas, such as cordon pricing, are not analyzed here means only that they are not yet ripe for analysis, not that they are without merit.

Implementation Mechanisms

Increase the Consumer Cost of Driving

Increasing the cost of automobile use can reduce fuel consumption and travel while encouraging the use of alternative fuels and public transit.

Encourage the Purchase of Low-GHG Vehicles

The state could adopt a variety of programs to increase purchase of fuel-efficient or low-GHG vehicles (including pure electric, hybrid, plug-in hybrid, and other alternative-fuel vehicles). State incentives could include lower registration fees, feebates, and/or tax credits. Higher vehicle registration fees could be charged for vehicles that have lower fuel economy and higher GHG emissions. Vehicle licensing fees could be based upon vehicle weight and/or emissions, for example, with use of a dollar per vehicle-ton multiplier instead of the present broad categories of vehicle weight.

Support PAYD Automobile Insurance

The state would encourage and support the provision of PAYD auto insurance, possibly including state support for additional pilot programs. This would also require the state Insurance Commission to conduct an active review of possibilities.

Related Policies/Programs in Place

MnDOT pilot underway to test VMT fees (no results are yet available), and PAYD insurance.

GMAC and OnStar Low-Mileage Discount Rates[20]

Since mid-2004, the General Motors Acceptance Corporation Insurance has offered mileage-based discounts to OnStar subscribers located in certain states. The system automatically reports vehicle odometer reading at the beginning and end of the policy term to verify vehicle mileage. Motorist who drive less than the specified annual mileage receive insurance premium discounts of up to 40%:

1–2,500 miles: 40% discount
2,501–5,000 miles: 33% discount
5,001–7,500 miles: 28% discount
7,501–10,000 miles: 20% discount
10,001–12,500 miles: 11% discount
12,501–15,000 miles: 5% discount
15,001–99,999 miles: 0% discount

This Federal Highway Administration's Value Pricing Pilot Program[21] is now providing funding for PAYD insurance simulation projects in Georgia and Massachusetts.

Distance-Based Program

Progressive Insurance[22] offers distance-based insurance in Oregon, Michigan, and Minnesota. The program uses Global Positioning System technology to track vehicle location and use.

TripSense(SM)

In August 2004, the Progressive Direct Group of Insurance Companies introduced TripSense, a usage-based auto insurance discount. The group notes:

> "Safer drivers and people who drive less than average should pay less for auto insurance. That's why we created the revolutionary TripSense(SM) discount program, which measures your actual driving habits and allows you to earn discounts on your insurance by showing us how much, how fast and what times of day you drive. TripSense gives you more control over what you pay for insurance, as your driving habits determine your discount."[23]

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[20] See http://www.onstar.com/us_english/jsp/low_mileage_discount.jsp.

[21] See http://www.fhwa.dot.gov/policy/13-hmpg.htm.

[22] See http://www.progressive.com.

[23] See http://newsroom.progressive.com/press-kit/tripsense-images.aspx.

Type(s) of GHG Reductions

Primarily CO_2.

Estimated GHG Reductions and Net Costs or Cost Savings

Data Sources:

The Arizona Public Research Interest Group (PIRG) Education Fund analyzed the potential GHG savings from a PAYD automobile insurance policy. The strategy for a PAYD policy analyzed assumes that insurers are required to offer mileage-based insurance for certain elements of vehicle insurance, including collision and liability. The Arizona PIRG Education Fund assumes the PAYD policy is required and phased in over time, and that all drivers in Arizona are eventually covered.

To calculate GHG savings, the Arizona PIRG Education Fund converted Arizona state automobile collision and liability insurance expenditures to an insurance cost per mile ($.064/mile). If insurance consumers pay 80% of their collision and liability insurance on a per-mile basis, then drivers would be assessed about a $.051/per mile. This per-mile insurance charge would reduce VMT by about 8%.[24] (To put this charge in context, at 20 mpg, $.051/mile = ~$1/gallon of gasoline.)

The TLU TWG compared the Arizona PIRG Education Fund results for estimated reductions in VMT with other studies of PAYD policies, including those produced by the Economic Policy Institute and Resources for the Future. The TWG found that the Arizona PIRG estimates were comparable with other estimates, which ranged from 8% to 20%, and used the 8% estimate.

Quantification Methods:

Impacts
Pilot studies and empirical experience with other marginal costs of use find that PAYD can reduce VMT by between 8% and 20%. If phase in/ramp up, then:

Apply reductions to light-duty vehicle (LDV) VMT only:

- 2015 reduction = statewide LDV × 4% reduction.
- 2015–2025 reduction = statewide LDV × 8% reduction.
- Convert to CO_2.

Net Present Value/Cost-Effectiveness
The success of the Progressive Insurance pilot in Texas suggests that there is an unmet demand for more choice in auto insurance. If PAYD improves and increases consumer choice, and also allows insurance providers to more efficiently align risks and premiums, economic efficiency will increase.

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[24] Elizabeth Ridlington and Diane E. Brown, *A Blueprint for Action: Policy Options To Reduce Arizona's Contribution to Global Warming*, Arizona Public Research Interest Group Education Fund, April 2006, pp. 25-26, available at: http://www.arizonapirg.org/AZ.asp?id2=23683. See also: http://www.serconline.org/payd/links.html, which links to a wide variety of PAYD studies and materials.

Key Assumptions:

State regulation of the Minnesota automobile insurance industry requires insurance companies to offer PAYD insurance, and eventual application of PAYD insurance to 50% of the LDV fleet.

Key Uncertainties

The specifics of the PAYD insurance programs are to be determined.

Until there is broader implementation beyond the current pilot programs, the effects of PAYD insurance on driver behavior are subject to significant uncertainty.

Until there is broader implementation beyond the current pilot programs, the economic impacts on insurance companies are unclear. A common question is, “If distance-based pricing is better, why do insurance companies not offer it without a mandate?”

In general, as has been demonstrated repeatedly in other consumer sectors, individual firms may innovate and not be followed by other firms for a wide variety of reasons, but when the market is transformed through policy changes, the industry adapts and remains healthy. Specifically regarding vehicle insurance:

> “Individual insurers face several barriers to implementing distance-based pricing. An individual company faces relatively high administration costs to establish an odometer auditing system. Insurance regulators are often unsupportive of pricing innovations. An individual insurance company only captures a small portion of the total benefits, since most financial savings are passed back to customers or accrue to competitors. Insurers do not profit from reductions in uncompensated crash costs, congestion, infrastructure costs, or pollution, or benefit directly from increased equity.
>
> “Insurance companies currently maximize profits by maximizing their gross revenue, because they are dependent on investment income. A pricing strategy that reduces total crashes could reduce profits if regulators or market competition required a comparable reduction in premiums. Although there are potential financial and marketing benefits, these longer-term savings would have to offset an individual insurer’s short-term revenue losses and risks. It is therefore not surprising that few insurers have implemented distance-based pricing.”[25]

Additional Benefits and Costs

Equity Impacts

Proponents argue that PAYD improves equity and fairness:

> “Current vehicle insurance pricing significantly overcharges motorists who drive their vehicles less than average each year, and undercharges those who drive more than average within each price class. Since lower-income motorists drive their vehicles significantly less on average than higher-income motorists, this is regressive. Distance-based insurance is fairer than current pricing because prices more accurately reflect insurance costs.
>
> “Distance-based pricing benefits lower-income drivers who otherwise might be unable to afford vehicle insurance, and who place a high value on the opportunity to save money by reducing vehicle mileage. It

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[25] Todd Litman, “Pay-As-You-Drive Vehicle Insurance: Converting Vehicle Insurance Premiums Into Use-Based Charges,” in *TDM Encyclopedia*, Victoria Transport Policy Institute, March 2007, available at: http://www.vtpi.org/tdm/tdm79.htm.

> benefits lower-income communities that currently have high, unaffordable insurance rates…. Distance-based insurance would provide significant savings to workers during periods of unemployment, when they no longer need to commute."[26]

Other equity issues may be addressed through policy design.

Feasibility Issues

None cited.

Status of Group Approval

Approved

Level of Group Support

Supermajority

Barriers to Consensus

Some MCCAG members viewed pricing of any amount as essentially punitive.

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[26] Litman, *ibid*. This article discusses a wide variety of questions about PAYD in some detail, and provides additional references.

TLU-6. Adopt California Clean Car Standards

Policy Description

This policy option reduces GHG emissions from new motor vehicles (cars and light-duty trucks) sold in Minnesota by adopting legislation equivalent to the California Clean Car standards (Assembly Bill 1493, also known as "Pavley" the name of the California lawmaker who sponsored the legislation).

California adopted legislation in 2002 (and regulations in 2004) requiring a reduction in GHG emissions from new cars and light-duty trucks sold in that state beginning with model year 2009. California plans an 8-year phase-in. The California standards incorporate the main global warming gases (i.e., CO_2, CH_4, and N_2O) resulting directly from the operation of the vehicle (tailpipe emissions), as well as hydrofluorocarbon (HFC) emissions resulting from leakage from or operation of the air conditioning system.

Policy Design

Goals: Adopt the California Clean Car program.

Timing: If adopted, the standards would take effect no earlier than the 2011 model year and would be phased in over a specified period of time (assuming the legislature would act in 2008).

Parties Involved: State legislature, Minnesota auto dealers.

Other: None.

Implementation Mechanisms

Adopt via legislation.

Current Legal Situation
The Clean Air Act allows California to establish its own vehicle emission standards, and to implement them after receiving a waiver from the EPA. Other states may then adopt the California standards. In December 2007, EPA denied California's waiver request. On January 2, 2008, California and 15 other states sued to have the EPA decision overturned.[27] Minnesota has since joined the lawsuit.

Given this situation, at least two possibilities for moving forward on this policy option present themselves:

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[27] "Besides Maryland and New York, the other states and agencies that joined the suit are Massachusetts, Arizona, Connecticut, Delaware, Illinois, Maine, New Jersey, New Mexico, Oregon, the Pennsylvania Department of Environmental Protection, Rhode Island, Vermont and Washington." From Keith B. Richburg, "California Sues EPA Over Emissions Rules: 15 Other States Back Effort To Win Waiver To Allow the Setting of Tougher Standards," *Washington Post*, January 3, 2008; page A02, available at: http://www.washingtonpost.com/wp-dyn/content/article/2008/01/02/AR2008010202833.html.

1. Minnesota could adopt the California standards and join the other states in awaiting the outcome of the current lawsuit.

2. Minnesota could use the time during which the lawsuits are argued to examine the issue in more detail via a legislative and/or Governor's Task Force.

Related Policies/Programs in Place

Since California's adoption of the Clean Car Standards, 12 additional states have adopted its standards.[28]

EPA is developing GHG standards for motor vehicles in response to a recent Supreme Court ruling.

The Energy Independence and Security Act of 2007[29] established a 35-mpg corporate average fuel economy (CAFE) standard for cars and light-duty trucks—that is, a 35-mpg requirement for the new-vehicle fleet—to be reached by 2020.

The California (AB 1493) standard differs from the new federal CAFE standard in many ways (Table H-3).

Table H-3. Comparison of California AB 1493 Standard and federal CAFE Standard

Features of the Standards	California Clean Car	HR 6 "Energy Bill" CAFE
1. Type of standard/what is regulated on new cars	GHG emissions per mile	Miles per gallon
2. Main target dates	2016	2020
3. Ending targets, in mpg equivalents	36 mpg[30]	35 mpg

Each of these three differences affects both the likely GHG and other emission reductions in Minnesota and the costs and benefits of those reductions.

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[28] The 13 states have about one-third of the nation's registered automobiles (California Air Resources Board Technical Assessment: Comparison of Greenhouse Gas Reductions Under CAFE Standards and ARB Regulations Adopted Pursuant to AB1493, January 2, 2008, available at: http://www.arb.ca.gov/cc/ccms/ab1493_v_cafe_study.pdf. In one view, these states are such a large portion of the auto industry sales, that automotive manufacturers would most likely improve technologies for all vehicles, rather than utilize inefficient two-tier production lines.

[29] See http://www.whitehouse.gov/infocus/energy/

[30] California Attorney General's Office, "A Comparison of California GHG Standards and the Senate CAFE Target," November 9, 2007:

"The automobile industry is asserting, in its litigation against the States, that the model year 2016 standards are equivalent to 43.2 miles per gallon (mpg) for the PC/LDT1 category and 26.7 mpg for the LDT2 category. In California, the PC/LDT1 category has about 58% of the entire fleet. (Other States have roughly that percentage, or have more LDT2s, and so compliance with California's standards will most assuredly ensure compliance with the California standards adopted by other States.) Thus, even assuming the automobile industry's assertions (which are based solely on tailpipe emissions of carbon dioxide from traditional gasoline powered vehicles), the California standards when fully phased in are equivalent to a fleet-wide average of approximately 36 mpg."

Type of Standard

When calculating GHG emissions per vehicle per mile, California Clean Car takes into account GHG emission reductions from the air-conditioning system as well as the tailpipe, and tailpipe calculations can take into account different fuel types. The following information is from the California Attorney General's comparison of the California standards and the new CAFE standard:[31]

GHG Emission Reductions from Air Conditioning

Analysis by California suggests that substantial, speedy reductions in GHG emissions per vehicle are available from further controlling air-conditioner emissions:

> "The California GHG standards establish a credit scheme for air conditioning improvements. These improvements include hoses and connections that leak less, refrigerants with less global warming potential, and more efficient systems. We expect most manufacturers to take advantage of these air conditioning credits, given the state of technology and the low costs involved. The credits can be as much as 18.5 CO2-e grams per mile (g/mi) per vehicle. This is the equivalent of between 1 and 3 mpg, with it being more significant with more fuel efficient vehicles. As an example, a manufacturer that meets the California model year 2014 standards through other improvements can meet the model year 2016 standards just by adding air conditioning improvements."

GHG Emission Reductions from Alternative Fuel Use

> "The California GHG standards also provide credits for the use of alternative fuels. These include ethanol (E85), natural gas, electricity (including plug-ins), and hydrogen. These credits are based on the lifecycle emissions of the fuels, to take into account upstream emissions, and will be calculated based on certification data that the manufacturers provide (as a matter of course) to the California Air Resources Board. Different fuels have different greenhouse gas emissions, even holding fuel economy constant. Because of this, the greenhouse gas "footprint" of cars does not necessarily match their fuel efficiency.
>
> "These alternative fuel credits have great potential. For example, for every vehicle run exclusively on corn-based E85, automobile manufacturers will receive a credit of 26% of that vehicle's tailpipe emissions due to the significantly lower upstream emissions from growing and producing corn-based ethanol (the credit would be even higher if the source of the ethanol were to change to cellulosic or sugarcane). For a car run exclusively on electricity (and with zero tailpipe emissions), the regulation sets the emissions at 130 CO_2e g/mi (to account for greenhouse gases in producing the needed electricity), well below the fleet-average standard for model year 2016."

Both California and CAFE set up various arrangements for trading credits, which also add flexibility.

Type(s) of GHG Reductions

CO_2, CH_4, and N_2O resulting directly from the operation of the vehicle (tailpipe emissions).

HFC emissions from leakage from or operation of the air-conditioning system.

Estimated GHG Reductions and Net Costs or Cost Savings

Summary

The new CAFE standard, having been signed by President George W. Bush, now becomes part of the Minnesota baseline. Because the California Clean Car standards reach *higher* mpg-

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[31] Ibid.

equivalencies *sooner*, they would produce additional GHG emissions reductions in the MCCAG timeframe on top of the new CAFE standard. Also, because the California Clean Car standards allow more ways to reduce emissions than the CAFE standard provides, all else being equal, the California standards should be able to produce equivalent, cheaper improvements in miles per gallon.

Analyzing the new CAFE standard's impact on the baseline, and thus the additional reductions that could be gained from California Clean Car, is made very difficult by the fact that the Energy Independence and Security Act of 2007 not only sets new MPG targets, but also changes the way those targets will be implemented. The law requires the National Highway Traffic Safety Administration (NHTSA) to develop the details of the new approach. In advance of those details, analyses must make assumptions about how the new CAFE standard would be implemented. Those assumptions are explicit in the analysis below.

GHG Reductions

The figures below represent the impact that the California Clean Car standards would have on Minnesota, in addition to the impact of the new CAFE standard of 35 mpg.

Policy No.	Policy Recommendation	GHG Reductions* ($MMtCO_2e$)		
		2015	2025	Total 2008–2025
TLU-6	Adopt California Clean Car Standards	0.74	1.16	13.10

This analysis is based on a document recently released by CARB (see data sources below) that compares the impacts of the California Clean Car standards and CAFE standards on California and other states. It estimates the amount of GHG emissions that each of the two standards would reduce independently of one another.

The 2007 Energy Bill mandates that fleetwide average fuel economy reach 35 mpg in model year 2020. It does not establish the implementation schedule and the precise mpg standards for each vehicle class, but directs the U.S. Secretary of Transportation to establish these. Since precise standards have not yet been established, CARB estimated that implementation would begin in model year 2011, and that fuel economy for each vehicle class would increase at a steady rate of 3.37% per year. The TLU TWG used this assumption in its analysis.

The California Clean Car standards are stated in terms of GHG emissions (grams per mile). The CAFE standard is stated in terms of MPG. Although the one metric is not directly convertible to the other, CARB's analysis provides a best-fit translation.

The TLU TWG's analysis adapts CARB's analysis to Minnesota, and judges CARB's methodology to be a sound comparison of the two standards for California's LDV (light-duty vehicles) fleet. For Minnesota, we use available data on the national fleet. We are not aware of any detailed data on vehicle population and activity rates for the Minnesota fleet. We also delay the implementation of the California standards by two years relative to California's schedule, in accordance with the policy design of TLU-6. Beginning implementation with the 2011 model year rather than 2009, Minnesota reaches the final standard in 2018 rather than 2016.

We calculate the impact of simultaneous enforcement of both the California standards and the CAFE standard. One standard may be stricter for passenger cars, while the other is stricter for larger trucks and sport utility vehicles (SUVs). With simultaneous enforcement, the stricter standard in each vehicle class ultimately determines vehicle emissions.

Step by step, we calculate GHG emissions as follows:

1. Calculate proportions of LDV VMT by vehicle age (activity rates) from MOBILE6 (EPA vehicle emission modeling software) defaults for the national fleet.
2. Apportion forecast VMT in each calendar year to vehicle model years.
3. Calculate average emission rates for the LDV fleet in each model year for two policy scenarios:
    a. CAFE only, and
    b. CAFE + California Clean Car standards.
4. For each calendar year, calculate emissions from vehicles in each model year under the two policy scenarios.
5. For each calendar year, calculate total LDV emissions under the two policy scenarios.

Table H-4 compares emission reductions from light-duty vehicles in Minnesota under each of the three scenarios to baseline emissions.

Table H-4. Comparison of emission reductions

Emission Reductions (MMtCO$_2$e)	2015	2025	2008–2025
New CAFE standards	1.32	6.02	43.51
California Clean Car Standards	1.57	5.67	44.20
CAFE + California Clean Car	2.06	7.18	56.62

Key Assumptions:

- New LDVs in Minnesota will be 50% passenger cars and small trucks and 50% large trucks and SUVs. This assumption is consistent with CARB’s assumption for the federal fleet.
- No implementation schedule has been set for the CAFE standard. We assume that phase-in of the standard begins in 2011, with a steady proportional increase in fuel economy of 3.37% per year for both vehicle classes. This assumption is consistent with CARB’s analysis.
- Both the California Clean Car and the CAFE standards would be enforced simultaneously. This assumption differs from CARB’s analysis, which compared the separate enforcement of the two standards.

- Fleet turnover rates and average activity rates for the national fleet are representative of Minnesota's fleet of LDVs.

Data Sources:

- Default values for fleet population and activity by vehicle age from EPA's MOBILE6 model.
- VMT projections from the Minnesota GHG Inventory and Projections.
- California Environmental Protection Agency Air Resources Board fact sheet: "Climate Change Emission Control Regulations," December 10, 2004, available at: http://www.arb.ca.gov/cc/factsheets/cc_newfs.pdf.
- California Environmental Protection Agency Air Resources Board. "Regulations to Control Greenhouse Gas Emissions from Motor Vehicles: Final Statement of Reasons," August 4, 2005, available at: http://www.arb.ca.gov/regact/grnhsgas/fsor.pdf.
- California Environmental Protection Agency Air Resources Board, "ARB Staff Reponses to Comments Raising Significant Environmental Issues Regarding the Proposed Regulations to Control Greenhouse Gas Emissions from Motor Vehicles," August 4, 2005, available at: http://www.arb.ca.gov/regact/grnhsgas/att3.pdf.
- California Environmental Protection Agency Air Resources Board, "Comparison of Greenhouse Gas Reductions Under CAFE Standards and ARB Regulations Adopted Pursuant to AB 1493," January 2, 2008, available at: www.arb.ca.gov/cc/ccms/ab1493_v_cafe_study.pdf.
- Energy Independence and Security Act of 2007, HR6.
- Natural Resources Defense Council, "Comments on the Proposed Adoption of Regulations by the California Air Resources Board (CARB) To Control Greenhouse Gas Emissions From Motor Vehicles," September 23, 2004, available at: http://www.nrdc.org/globalWarming/crh0904.pdf.
- Daniel Sperling et al., "Analysis of Auto Industry and Consumer Response to Regulations and Technological Change, and Customization of Consumer Response Models in Support of AB 1493 Rulemaking," Institute of Transportation Studies, University of California, Davis, June 1, 2004, available at: http://www.its.ucdavis.edu/publications/2004/UCD-ITS-RR-04-17.pdf.

Costs/Savings Summary

Before the establishment of the new CAFE standard, CARB estimated that the ultimate GHG standards would add an average cost of $1,064 per vehicle and that the fuel savings would more than offset those additional costs. CARB further estimated that the fuel savings, by starting immediately, would immediately begin offsetting the higher costs of a leased or financed vehicle.

In addition, before the establishment of the new CAFE standard, the auto industry estimated the average cost per vehicle would be $3,000 for complying with the new CAFE requirements, and that the fuel savings would not offset that higher cost. The auto industry estimated that the higher initial cost would delay the turnover of the fleet to cleaner, safer vehicles.

These figures remain the same under the new CAFE standard, but a portion of those costs will be incurred under the new baseline. Isolating the cost of the additional California reductions would require an analysis of auto industry cost curves, beyond the scope of this analysis.

As noted above, California believes that its inclusion of credits from air-conditioning measures increases manufacturer freedom and thus reduces costs relative to a tailpipe-only approach.

Data Sources/Quantification Methods/Key Assumptions

Issue: CARB and automakers disagree on the cost of compliance with California Clean Car standards. As described above, CARB estimates that the additional cost of compliance for a new car in model year 2016 would be approximately $1,000 and that the net benefit to consumers, accounting for reduced fuel consumption, would be slightly positive. Automakers contended that the price would be in the vicinity of $3,000 and that the net benefit to consumers would be negative.

CARB's cost estimates were based on existing and emerging technologies that can improve fuel economy in passenger vehicles. CARB included a number of conservative elements in its methodology:

- Standards were based on the heaviest manufacturer fleet.
- Multiple feasible technology packages were ensured for each vehicle class.
- Emission reductions from hybridization were excluded.
- Fuel price was assumed to be $1.74 per gallon.[32]

CARB's analysis estimated that the additional cost of compliance in a new vehicle in model year 2016 will be approximately $1,000. To determine the net impact on consumers, CARB calculated the increase in monthly loan payments versus the savings from reduced fuel consumption. Consumers would achieve a net savings of approximately $3.50–$7.00/month.

An analysis by Sierra Research, Inc., commissioned by the Alliance of Automobile Manufacturers, estimated that the average cost of compliance with AB 1493 would be around $3,000 per vehicle and that savings on fuel would offset less than half of that cost for consumers. The Sierra finding was largely a result of its assumption that greater fuel economy would encourage consumers to drive significantly more (the "rebound effect"). The CARB analysis also took this effect into account but estimated its impact to be smaller.

Sierra also expected more expensive technologies and options to be used, where CARB anticipated simpler, less costly technologies. More than $2,000 of the cost increase estimated by Sierra resulted from the use of expensive light-weight aluminum body structures typically found

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[32] CARB, ARB Staff Reponses to Comments Raising Significant Environmental Issues Regarding the Proposed Regulations To Control Greenhouse Gas Emissions From Motor Vehicles, August 4, 2005, available at: http://www.arb.ca.gov/regact/grnhsgas/att3.pdf, page 1.

in sport luxury cars. Such structures are not feasible for use in typical passenger vehicles. In addition, AB1493 prohibits the use of such weight-reduction approaches.[33]

Finally, the Sierra analysis appears internally inconsistent. If consumers do not see net savings from the purchase of a California Clean Car, then there is no extra money for them to spend on additional driving.[34] The CARB analysis acknowledges the rebound effect from its savings, but does not expect (nor does any study of the rebound effect find) that consumers would use up all their savings in additional driving.

Getting away from the debate over CARB analyses, several academic studies of likely California standard costs also find net consumer saving. For example, Table H-5 shows the results of a University of Michigan study.[35]

Table H-5. Vehicle lifetime savings to consumers with Pavley auto standards

Cost Factors	Car	Van	Pickup	SUV	Market
Lifetime fuel cost	–$2,432	–$3,090	–$3,712	–$3,786	–$2,928
Retail price	$1,253	$989	$1,367	$1,242	$1,275
Total change (savings)	–$1,178	–$2,100	–$2,344	–$2,544	–$1,652

There is substantial empirical basis to expect that both CARB and the industry have overestimated compliance costs. A review by the Natural Resources Defense Council found that the auto industry has typically overestimated the compliance costs of pollution standards for passenger vehicles by a multiple of between 2 and 10. Factors that contribute to overestimation include unanticipated innovation and overly conservative estimates. Regulators have also overestimated compliance costs in the past, by a factor of as much as 2.[36]

The question of how much higher initial costs affect vehicle turnover is likewise the subject of extensive study and debate. Auto manufacturers generally argue—and various researchers, including Sierra Research, find—that higher prices slow turnover, to the detriment of the goal being sought through regulation. (This is a problem in no way limited to auto regulations.) On the other side, research exemplified by that done at the University of California, Davis argues that it is difficult to find an empirical basis for claims that past fuel economy (or safety) regulations have meaningfully slowed fleet turnover.[37]

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[33] CARB, Regulations To Control Greenhouse Gas Emissions From Motor Vehicles: Final Statement of Reasons, August 4, 2005, available at: http://www.arb.ca.gov/regact/grnhsgas/fsor.pdf, page 169.

[34] See Meszler Engineering Services, "Response to Sierra Massachusetts Pavley Comments, November 22, 2005, available at: http://www.mass.gov/dep/air/laws/meszler.pdf.

[35] Walter S. Mcmanus, "Economic Analysis of Feebates to Reduce Greenhouse Gas Emissions from Light Vehicles for California," University of Michigan Transportation Research Institute, Ann Arbor, Michigan, UMTRI-2007-19-2, May 2007. http://www.umtri.umich.edu/content/UMTRI-2007-19-2.pdf

[36] Natural Resources Defense Council, Comments on the Proposed Adoption of Regulations by the California Air Resources Board (CARB) to Control Greenhouse Gas Emissions from Motor Vehicles, September 23, 2004, available at: http://www.nrdc.org/globalWarming/crh0904.pdf, page 6.

[37] A recent example is Daniel Sperling et al., Analysis of Auto Industry and Consumer Response to Regulations and Technological Change, and Customization of Consumer Response Models in Support of AB 1493 Rulemaking,

Conclusion

With the passage of the new federal CAFE, all of these analyses are now out-of-date. A portion of the estimated costs and benefits will be incurred under the new baseline. If we allocate the use of the simpler, more cost-effective technology upgrades to the new CAFE baseline, the cost-effectiveness of the additional compliance with the California Clean Car Standards is likely to decrease. Isolating the cost of the additional emission reductions from the California Clean Car Standard would require an analysis of auto production cost curves, which is beyond the scope of this analysis. Such an analysis might find either positive or negative net costs for consumers.

In any case, the cost of new CAFE + California Clean Car cannot exceed the cost of California Clean Car on its own. Although it is possible that the CARB cost estimates of compliance are too low, the TLU TWG believes the CARB analysis is more thorough and overall more credible. Therefore, we continue to show cost savings for CAFE + California Clean Car.

Cost summary

A review of $/ton estimates prepared for the Pavley-type regulation for CARB, Northeast States for Coordinated Air Use Management, and the TLU TWG produces an estimate of between $117 saved for each metric ton of CO_2e reduced at the high end, and roughly one-third of that (~$39 saved for each ton) at the low end. The TWG used the low end of that range, $39 saved per ton reduced.

Key Uncertainties

Predicting how long it will take to resolve lawsuits over this issue is beyond the ability of this group. Clearly the law will be in litigation for some time.

According to auto manufacturers, vehicles for the 2011 model year are already being designed. New engine lines take 6–7 years to develop. Because of the timelines and requirements in the California GHG standards that occur in the 2010–2013 timeframe, the auto industry says that the only way to meet the standards in the early years would be to drop models.

The current highest court rulings on these claims found that in the courts' views, sufficient existing technology exists to allow manufacturers to meet the California standards.[38, 39]

Additional Benefits and Costs

Reducing the total amount of on-road fuel burned in Minnesota would, all else being equal, reduce emissions of ground-level pollution, with accompanying reductions in health impacts.

A joint study conducted in 2007 by NERA Economic Consulting, Sierra, and Air Improvement Resource (NERA/Sierra/AIR) concluded that California's low-emission vehicle (LEV) program results in higher levels of a variety of pollutants, including exhaust fine particulate matter

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Institute of Transportation Studies, University of California, Davis, June 1, 2004, available at: http://www.its.ucdavis.edu/publications/2004/UCD-ITS-RR-04-17.pdf.

[38] See http://www.vtd.uscourts.gov/Supporting%20Files/Cases/05cv302.pdf

[39] The December 11th decision in U.S. District Court for the Eastern District of California can be found at: http://ag.ca.gov/cms_attachments/press/pdfs/n1509_656_order_12-12-07.pdf

($PM_{2.5}$), NOx, volatile organic compounds, carbon monoxide, and air toxics.[40] The study evaluated the emission impacts of the entire California LEV program—criteria emissions, the zero-emissions vehicle (ZEV) mandate, and the GHG provision—on new LDVs in California, and compared them with those that would occur in the state under the federal vehicle emission standards. The key to the study's results is that "the new vehicle price increases resulting from the ZEV and GHG standards will affect fleet turnover by reducing new vehicle sales and inducing higher rates of retention of older, higher-emitting vehicles. These effects lead to increases in criteria pollutant emissions, as older vehicles in the fleet often have emission rates that are many times higher than those of new vehicles."

Although the set of regulations covered in the NERA/Sierra/AIR study is broader than just the California GHG regulations, the basic question is the same as discussed above under "Costs/Savings": Do higher initial prices slow turnover to the extent that the regulatory goal sought in the new fleet is reversed? While the TLU TWG has not reviewed the entire literature on this subject, of those cited here, it finds the CARB and other studies finding "no" to be stronger overall for the reasons given above.

Feasibility Issues

Manufacturers have stated under oath that they cannot meet the California GHG standards using their current mix of models. They would attempt to comply by severely restricting model availability.

There is some concern that California standards may constrain the sale of E85 vehicles. This is due to the partial ZEV standard and the testing on worst-case blend of fuel (E10). It may require switching back to metal fuel tanks, which add weight and packaging issues. Also, super-ultra-LEV tailpipe emissions are difficult at cold temperatures required by CARB, because hydrocarbon emissions exceed the standard before the catalyst is warmed up. This claim is disputed by the Union of Concerned Scientists which, through its Vanguard program, has designed a full range of vehicle types that meet the California standards and run on E85 (see www.ucsusa.org/clean_vehicles/vehicles_health/ucs-vanguard.html). The fact that California Clean Car gives credit for E85 vehicles also suggests that this is unlikely to be a major barrier.

Status of Group Approval

Approved

Level of Group Support

Majority

Barriers to Consensus

The discussion above was produced through work by members of the TLU TWG. It would be incorrect to characterize any part of it as a consensus on the part of the TWG. The following two

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[40] NERA/Sierra/AIR, "Effectiveness of the California Light Duty Vehicle Regulations as Compared to Federal Regulations," June 15, 2007. So far as the Center for Climate Strategies (CCS) knows, this study is not available online. CCS will e-mail it to any interested reader.

sections are statements by two individual TLU TWG members are provided in an effort to capture the sources of disagreement about this option.

SCOTT LAMBERT

Representatives of the automobile industry participating on the Transportation and Land Use (TLU) Technical Work Group (TWG) strongly oppose the inclusion of California's low-emission vehicle (LEV) standard (CA LEV) as a recommendation in the MCCAG's final report.

CA LEV is a program designed by California legislators and regulators—none of whom is accountable to Minnesota or its residents. By adopting CA LEV, Minnesota is ceding its authority to a state that is vastly different and tying itself to all future regulatory changes that California makes. Divergent market trends, economic drivers, natural resources, and air quality concerns separate Minnesota and California. Adoption of CA LEV will lead to repercussions not only in the automobile industry, but also in the agriculture, tourism, mining, forestry, construction, ethanol, and many other industries.

In the wake of recent federal activity pertaining to both state and national fuel economy standards, TLU-6 does not align with MCCAG's stated goal of reducing GHG emissions in the state and should not be included in the final report.

Recent Developments

In December 2007, the Renewable Fuels, Consumer Protection, and Energy Efficiency Act (H.R. 6) was signed into law. This legislation's centerpiece was an unprecedented increase in Corporate Average Fuel Economy (CAFE) standards. Not only is H.R. 6 historic because it is the first increase in fuel economy standards by Congress since 1975, but it *requires a dramatic 40% increase in mileage standards* by 2020.

This comprehensive and aggressive response to the climate change issue will result in a *30% reduction in* CO_2 *emissions from individual vehicles* by 2020. These new standards present one of the biggest challenges in the automobile industry's history, and will require automakers to continue creating, developing, and introducing cutting-edge, fuel-efficient vehicles.

Not only will H.R. 6 provide significant reductions in CO_2 emissions, but it will also reduce our nation's dependence on foreign oil and increase the production of clean and alternative fuels. H.R. 6 is estimated to *save 18 billion gallons of gasoline per year* by 2020, as compared with projected consumption levels—the equivalent of taking 30 million cars off the road. In addition, the legislation will *reduce oil consumption by 1.1 million barrels a day* in 2020, compared with projected consumption levels and *require that the United States produce 21 billion gallons of advanced biofuels.*

With the federal government's adoption of H.R. 6, the U.S. Environmental Protection Agency showed its support for a strong national program by denying California's request for a waiver to implement its own fuel economy regulations (AB 1493) as part of the preexisting CA LEV standards. This action prohibits California and all other states from implementing CA LEV's proposed fuel economy regulations. While this decision is being appealed by California and several other states, current law does not allow for the implementation of AB 1493.

In the wake of the waiver denial, states that have adopted or plan to adopt the CA LEV program are only adopting a smog- and ozone-forming emissions program that provides no environmental benefit above and beyond the existing federal program. *However, in adopting the CA LEV criteria-forming emission standards, states are effectively ceding their authority to unelected California regulators.*

The new CAFE law applies a high standard to all 50 states that is good for both consumers and energy security. The auto industry believes that states can also address the climate change issue —as it relates to the transportation sector—by supplementing the federal government's work and incentivizing the purchase and use of alternative-fuel and advanced-technology vehicles.

Comparison

Proponents of TLU-6 may point to the California Environmental Protection Agency's Air Resources Board's (CARB's) analysis comparing H.R. 6 and AB 1493. CARB's effort is flawed, largely due to the fact it compares an existing regulation (CA LEV) to a piece of legislation (H.R. 6) that is a regulatory scheme has yet to be created. In addition, CARB also attempts to compare H.R. 6 in 2020 to "Phase 2" of California's fuel economy program. With "Phase 1" of California yet to be implemented, CARB cannot possibly predict how or when "Phase 2" of its regulation will take effect. *The analysis is using non-existent regulations from California's program to diminish H.R. 6, a tactic that is not reliable or credible.*

What we do know is that the requirements in H.R. 6 will be a challenge for auto manufacturers, since they represent an approximate 4% increase in fuel economy annually. Automakers will continue to create, develop, and introduce cutting-edge, fuel-efficient technologies in order to reach the 35-mpg standard by 2020. Comparatively, the California standards require up to a 14% improvement in fuel economy in just one year—an improvement that is technically infeasible absent product restrictions.

In addition, we know CA LEV's fuel economy standards will have a significant impact on Minnesota consumers, as explained below.

Facts About CA LEV

- A recent study by a team of experts from Sierra Research, Air Improvement Research, Inc., and NERA Consulting concluded that the implementation of CA LEV in its entirety—including the fuel economy standards—results in higher levels of a variety of pollutants, including exhaust $PM_{2.5}$, NO_x, volatile organic compounds, carbon monoxide, and air toxics. Why?
    - "Fleet Turnover Effect"—As vehicle prices increase as a result of added regulation, older vehicles, with less productive pollution controls than their newer counterparts, remain on the road longer.
    - "Rebound Effect"—As vehicle fuel economy increases, the cost of driving declines and vehicle operation increases.
- In litigation over the greenhouse gas standards, large-volume manufacturers stated under oath that compliance with the regulation is not technically feasible, absent product restrictions.

  - Significant reductions in vehicle choice will disproportionately impact Minnesota because of its unique market.
  - Minnesotans favor light-duty trucks and sport utility vehicles (SUVs), with a sales mix of approximately 55% trucks and 45% passenger cars. This is not surprising, given that Minnesota's economy is largely based on agriculture, tourism, mining and forestry, and construction.
  - In comparison, California—the state that designed the program and will retain control over the regulation—has a sales mix of approximately 49% trucks and 51% passenger cars.
  - *Consumer choice, specifically in reference to the availability of light-duty trucks and SUVs that Minnesota residents like to drive, will be severely limited.*
- Expert economists have predicted that consumers can expect to see an average increase of at least $3,000 in the cost of new vehicles sold in Minnesota.
  - Adoption of CA LEV will not support Minnesota's commitment to E85 technology and infrastructure.
  - Automobile manufacturers get no credit toward their CO_2 fleet averages for producing or selling E85 vehicles under the California program.
  - An expert retained by California to testify on the issue of alternative fuels stated, under oath, that it would not be prudent for vehicle manufacturers to rely on the sale of E85 vehicles to generate sufficient credits to comply with the greenhouse gas standards proposed in the CA LEV program.
  - California standards may constrain the sale of E85 vehicles. About 40% of all new vehicles are required to meet partial zero emission vehicle (PZEV) standards. *However, no E85 vehicle has EVER met the PZEV standard, nor has CARB demonstrated that it's even possible to meet the PZEV standard with an E85 vehicle.* Thus, CA LEV immediately eliminates about 40% of the E85 market.

JIM ERKEL

California Clean Car Standards versus New CAFE Standards

1. **The California clean car standards are not precluded by new CAFE standards.** As part of the Clean Air Act, California is allowed to set its own emission standards subject to EPA granting a waiver from the application of its national standards. Other states may adopt California's standards without the need for approval from EPA. The main argument of automobile manufacturers has been that the California clean car standards are the functional equivalent of a fuel economy standard and should be preempted or precluded by the CAFE standards adopted by the National Highway Traffic Safety Administration (NHTSA) under the Energy Policy and Conservation Act (EPCA). However, The U.S. Supreme Court recently held that greenhouse gases are pollutants within the meaning of the Clean Air Act. The Supreme Court stated that the possibility of overlap between EPA's authority under the Clean Air Act and NHTSA's authority under EPCA did not bar EPA from having to deal with carbon dioxide as a cause of air pollution. In addition, the U.S. District Court for the Eastern District of California recently held that, in dealing with the possibility of overlap, EPA need not defer to NHTSA, but rather that NHTSA must take into consideration EPA's standards in setting its CAFE standards. As Congress considered higher fuel economy

standards as part of the new energy bill, the Energy Independence and Security Act of 2007 (EISA), manufacturers lobbied to include language to require that EPA defer to NHTSA's standards. Instead, language was included at the request of California and a number of other states to make certain that EISA did not limit, alter, or modify other environmental laws and regulations, including the Clean Air Act. As a result, the new CAFE standards established in EISA do not change EPA's preferential position under the Clean Air Act for California's ability to set its own standards and waive out of EPA's standards, or the ability of states to adopt California's standards.

2. **The California standards will not establish a patchwork of regulation.** A related argument asserted by the automobile manufacturers is that allowing California to set standards and then letting other states adopt them would establish an unworkable national patchwork. This is not true. Under the Clean Air Act, there are only two possible standards—EPA's standards or California's standards for which waivers have been granted. If another state adopts California's standards, manufacturers will be able to sell the automobiles they are already making for California. In addition, the argument that a patchwork might develop fails to acknowledge that many states already apply California's non-greenhouse gas standards, and there is no suggestion it has been difficult for manufacturers to work out the shipment of vehicles between adopting and non-adopting states.

3. **The new CAFE standards are not sufficient.** James Hansen, one of the nation's top scientists studying climate change, recently suggested that the safe upper limit for atmospheric carbon dioxide may be 350 parts per million, rather than the 450 parts per million that most have assumed. He also noted that the world already stands at 383 parts per million. As a result, it is critical that we immediately begin taking steps to reduce greenhouse gas emissions. The California Air Resources Board (CARB) has estimated that its standards will reduce greenhouse gases more than the new CAFE standards. The new CAFE standards ramp up fuel economy for passenger cars from today's 27.5 miles per gallon to 35 miles per gallon in 2020. In contrast, the clean car standards ramp up between 2009 and 2016 and attain higher rates of emission reductions. The clean car standards will prevent the emission of 58 MMtCO$_2$-e in California between 2009 and 2016, more than three times the 20 MMtCO$_2$-e if only the new CAFE standards are applied. California is already committed to establishing a second round of standards that would take effect between 2016 and 2020. Taking these second-round standards into account, the clean car standards would prevent 167 MMtCO$_2$-e in California by 2020, which is more than twice the 76 MMtCO$_2$-e if only the new CAFE standards are applied. Given the effects of climate change that it confronts, Minnesota should take advantage of the benefits of the quicker ramp-up and higher reduction potential that would be afforded by adopting California's clean car standards.

4. **The automobile manufacturers can meet the California clean car standards.** The manufacturers have argued that the lead time to go from concept to production means that they can't meet California's clean car standards. In considering its standards, though, CARB identified existing technologies already being used in automobiles that would be sufficient in the near term. In fact, the Director of Communications for the Alliance of Automobile Manufacturers acknowledged that "[e]ighty percent of the technology [CARB] . . . identified is currently available on cars and light trucks…. California's rules could aim for 30 percent emissions cut." (*San Diego Union Tribune*, June 9, 2004). In addition, California's standards

provide several opportunities for flexibility that do not exist in the new CAFE standards. For example, California sets different emission rates for cars and trucks and allows credits to be traded between them, establishes credits for the use of alternative fuels, including E85, and sets up a credit scheme for air conditioning improvements. The California Attorney General has noted that assuming fuel economy of 35 miles per gallon and full use of the air conditioning credits, gasoline-powered vehicles would meet California's standard in 2012 and would need only an additional 12% reduction to meet the standard for 2016.

5. **The cost of meeting the California Clean Car standards will not be substantial.** In considering the clean car standards, CARB estimated the added cost per vehicle of meeting the standards would be about $375 in the short term, and as fully phased in the mid-term would be about $1,000. In contrast, the manufacturers argued that the cost would be more than $3,000. A study of CARB's previous technology-forcing regulations shows that the actual costs of control imposed by its regulations have been lower than CARB's estimates, and in some cases only a tenth of manufacturers' estimates. In addition, CARB found that the additional vehicle cost would be more than offset by savings in operating costs. Assuming a gas price of $1.74 per gallon, CARB estimated that for every $1 of cost resulting from the standards, consumers would save between $5 and $11. The Union of Concerned Scientists estimated that at a gas price of $2 per gallon, the cost of the technologies to meet the clean car standards would pay for themselves in less than a year and a half of average driving.

6. **Buyers are already expressing a preference for more fuel-efficient vehicles.** The manufacturers have argued that buyers have preferred larger, heavier vehicles and this preference will not change. As a result, they have claimed that the clean car standards might force them to withdraw some vehicles from the market. In fact, much of the testimony presented by manufacturers in a 16-day trial on these issues in U.S. District Court for Vermont assumed that vehicle weights would continue increasing and that buyer preferences will not change from the 2004 model mix. The District Court dismissed the manufacturers' claims as "unconvincing," "improbable," "highly unlikely," and "not credible." The District Court noted that Chrysler Group posted a loss for 2006 of $1.4 billion and stated the loss was due in part to a shift in consumer demand for better fuel economy and smaller vehicles. The District Court pointed out that Chrysler's plan to recover from this loss included a new focus on fuel-efficient vehicles. The recent release of 2007 vehicle sales information substantiates the District Court's conclusion. A recent article from *Auto Observer* notes that Toyota passed Ford as the No. 2 automaker in the United States, and highlighted the fact that 2007 sales of Toyota's Prius hybrid increased by 68.9%, outselling several full-line brands. In fact, the Prius outsold every Ford vehicle, except the F-Series pickup truck.

7. **The California Clean Car standards will not increase other vehicle-based air pollution.** The manufacturers have argued that the adoption of California's clean car standards will have the effect of increasing of other vehicle-based air pollution. This argument is based on the manufacturers' assumption that buyer preferences will not change. The manufacturers argue that the lack of technological solutions for meeting the standards means that they may have to withdraw some vehicles from the market, and the technological solutions that do exist will add substantially to the cost of each vehicle. Because of this, manufacturers claim that buyers will postpone buying cleaner new vehicles and will increase their driving due to the lower cost of operating older vehicles. As already noted, though, the needed

technological solutions are already in the market, the cost of the standards will be less than the manufacturers claim, higher gas prices will mean that the cleaner new vehicles will quickly offset such costs and substantially raise the cost of operating the less efficient older vehicles, and market information shows that buyers are already moving in the direction of cleaner vehicles. As a result, the rebound effect suggested by the manufacturers is unlikely to play out as they suggest.

TLU-7. “Fix-it-First” Transportation Investment Policy and Practice

Policy Description

This policy option recommends that the state legislature require that state and federal transportation investments be prioritized in the following order: (1) maintain existing roads, and (2) design new and expanded roads to serve higher-density, more compact, pedestrian-friendly development in priority growth areas, such as downtowns, town centers, main streets, neighborhood hubs, regional centers, transit corridors, and transit station areas. It also recommends that the state significantly reduce investment in new roads and roadway expansion that accommodates and encourages both low-density development and more and longer vehicle trips.

This strategy will reduce GHGs emissions by increasing bicycling and walking and reducing the number and length of vehicle trips. (It accounts for part of the VMT reduction goal, along with TLU-1, -2, -5, -9, and -14.)

Policy Design

Goals: Place a much higher priority on maintenance of existing roads. Strategically target roadway expansion dollars as described above. Expansion projects comprise approximately 40% (approximately $600 million) of $1.6 billion in transportation investments planned for 2008–2011 in the Twin Cities metropolitan area. (See metro Transportation Improvement Plan document page 48).

Timing: Legislation drafted in 2008–2009 and adopted in 2009; changes in investments, starting in 2011 (the federally required Transportation Improvement Program document with listed projects is already in place for 2008–2011). Need legislation adopted by 2009 that identifies goals and investments policies, including targeted growth areas, implementation steps, etc.

Parties Involved: MnDOT, local government, MC, state legislature, developers, business community.

Other: None cited.

Related Policies/Programs in Place

Recent Actions in Minnesota:

The regional highway plan in the MC Transportation Policy Plan states that highway expansion investments are only considered after preservation and management investments have been funded.

Type(s) of GHG Reductions

Mostly CO_2.

Estimated GHG Reductions and Net Costs or Cost Savings

Contributes to total VMT goal; not separately analyzed.

Key Uncertainties

None cited.

Additional Benefits and Costs

Safety from improved existing infrastructure.

Feasibility Issues

None cited.

Status of Group Approval

Approved

Level of Group Support

Super Majority

Barriers to Consensus

View that MnDOT already pursues this policy.

TLU-9. Workplace Tools To Encourage Carpooling, Bicycling, and Transit Ridership

Policy Description

Reduce emissions by requiring certain employers and encouraging other employers to offer a Commuter Benefits (CB) program at the workplace to increase the use of transit, ride-sharing and non-motorized transportation. Commuter Benefits include reducing the amount of free or subsidized parking; providing paid or pre-tax transit passes or mode-neutral transportation allowances; guaranteeing rides home for non-drive-alones; providing bicycle parking and employee lockers; providing telecommuting programs; and converting employee ID cards to transit passes. In addition, reduce emissions by requiring large employers (more than 200 employees) to develop and implement transportation demand management (TDM) plans that customize commuter benefits and transit-supportive building design to specific building locations. (It accounts for part of the VMT reduction goal, along with TLU-1, -2, -5, -9, and -14.)

Policy Design

Goals:

Commuter Benefits

- All Minnesota non-rural employers with more than 200 employees located within an incorporated municipality offer CB programs.
- All colleges and universities offer CB programs.
- All government units offer CB programs, especially the state of Minnesota.
- Minnesota adopts employee parking management and incentive programs to promote alternatives to single-occupant vehicle (SOV) commuting.

Commuter Choice

- Minnesota establishes a public-private partnership to develop and run telecommuting centers that offer office-type services in locations close to commuters' residences.
- Minnesota establishes best practices in transportation demand management (TDM), and assists employers of over 200 employees in developing and implementing TDM plans. (The state is already committed to doing this in the Twin Cities metropolitan area through Metro Transit and five transportation management organizations.)

State Tax Credits for Employer-Provided Commuter Benefits

- Expand the current Minnesota Employer Transit Pass tax credit to include more employers and more commuters (e.g., nonprofit organizations and commuters who bike, carpool, or telecommute).

Timing: Implement by 2010.

Parties Involved: MC, state colleges and universities, other colleges, municipalities, transit providers, transportation management organizations, employers, state legislature.

Other: None.

Implementation Mechanisms

Expand the current Minnesota Employer Transit Pass tax credit, and establish technical assistance for employers.

Related Policies/Programs in Place

Employee Discount Transit Passes: Metro Transit offers passes for regular-route bus service for sale to employers at a 30% special discount rate for their employees to promote mass transit and reduce both congestion and emissions in the Metro area. (See http://www.metrotransit.org/groupDiscProg/metroPass.asp.)

Type(s) of GHG Reductions

Primarily CO_2.

Estimated GHG Reductions and Net Costs or Cost Savings

Policy No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$)			Net Present Value 2008–2025 (Million $)	Cost-Effective-ness ($/t$CO_2$e)	Level of Support
		2015	2025	Total 2008–2025			
TLU-9	Workplace Tools To Encourage Carpooling, Bicycling, and Transit Ridership	0.3	0.4	4.5	Large net savings	Large net savings	UC

Data Sources:

- ICF Consulting, *Analyzing the Effectiveness of Commuter Benefits Programs*, Transit Cooperative Research Program Report 107, 2005.[41]
- ICF Consulting, *Strategies for Increasing the Effectiveness of Commuter Benefits Programs,* Transit Cooperative Research Program Report 87, 2003.[42]

Quantification Methods:

Sixty-four percent of Minnesotans work for employers with 50 or more employees. This analysis assumes that half that figure, or 32%, work in covered employers.

Key Assumptions:

GHG Impacts
After the introduction of a CB program at covered companies, transit usage increases by 25% in 2015, and 30% in 2025.

More than half of the surveys reported an increase in transit riders between 10% and 40%, and nearly one-quarter reported increases of more than 60%. Two surveys—one in San Jose in 1997

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[41] See http://onlinepubs.trb.org/onlinepubs/tcrp/tcrp_rpt_107.pdf

[42] See http://onlinepubs.trb.org/onlinepubs/tcrp/tcrp_rpt_87.pdf

and one in Atlanta in 2003—suggest that transit ridership more than doubled after a transit benefits program was implemented.[43]

Table H-6. Projected percentages of commuting, VMT and workplaces/employees affected under a Minnesota Commuter Benefit program/

	2015	2025
Percentage of VMT that is commuting-related	25%	25%
Percentage of Minnesota employees affected	32%	32%
Average percentage VMT reduction per work place	25%	30%

To calculate VMT reductions, multiply baseline light-duty VMT by the above percentages. These VMT reductions are then converted to CO_2e to calculate the emissions reductions from a Minnesota CB program.

Costs

The costs of providing commuter benefits at the work place varies widely. Although contributing to employee CB financially produces the largest mode shifts, simply allowing an employee to participate in a pre-tax transit pass deduction actually saves the employer money, and generally produces almost as much mode shift. Employers also save money on parking. In a national survey of employers about why they did or did not offer commuter benefits, the main concern was not cost, but the administrative difficulty factor of adding an additional benefit.

At the IRS mileage rate of $0.49/mile, cost savings to commuters would total more than $400 million a year in 2025 (Table H-7).

Table H-7. Potential cost savings from CB program

	2015	2025
Total VMT reduction	704,913,896	993,972,902
@ $0.49/mile	$345,407,809	$487,046,721

At the University of Minnesota's *Full Cost* study rate of $0.84/mile, in 2025, total social savings from reduced VMT would be more than $800 million a year.

Since the policy option does not require a workplace contribution to a CB, only that one be offered, which can be satisfied through a no-cost pre-tax option, the TWG does not subtract employer costs from these benefits.

Because these numbers start to look very large over the time frame of the study, the TWG preferred to convey them as "large net savings."

Key Uncertainties

None cited.

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[43] ICF Consulting, Analyzing the Effectiveness of Commuter Benefits Programs, p. 43.

Additional Benefits and Costs

Commute times are the most congested time of day; reductions in peak-period commuting can have substantial benefits for traffic flow and congestion relief.

Feasibility Issues

None cited.

Status of Group Approval

Approved

Level of Group Support

Unanimous

Barriers to Consensus

None

TLU-12. Voluntary Fleet Emission Reductions

Policy Description

Under this policy, Minnesota would create new services and add additional support to existing voluntary and incentive-based programs that help private fleets reduce their GHG emissions.

Approximately 10% of cars and trucks in Minnesota are in fleets. There are many ways for businesses to voluntarily reduce GHG emissions from their fleets. Typically, fleets will determine a methodology to measure their GHG impact, review their current vehicle mix and vehicle operation parameters, and then analyze options to see where efficiencies can be gained. Efficiencies generally come through improved driver behavior, more efficient vehicles (either new models or technology enhancements to existing models), and/or improved operating processes (e.g., more efficient routing systems).

This current state in private fleet efficiency programs points to certain challenges. First, there is no centralized support to help fleets manage these initiatives. Fleets have little support in selecting which metrics to measure and how to do it. Second, funding resources for retrofits and other technology-based efficiency solutions are limited and may be restricted to specific vehicle types. Part of this challenge is necessary because some solutions for heavy duty trucks are inherently different from what a fleet of sedans would be facing. Third, there is no centralized, Minnesota-based registry for businesses to post, track, and share fleet-based GHG improvements.

Policy Design

Goals: The primary goal of this policy would be to reduce the amount of total fleet generated GHG emissions by falls by 5% a year.

Levers that fleet managers can operate to mitigate the GHG impact of their fleets include:

- Managing fleet size (e.g., retiring unused vehicles),
- Right-sizing engines for business need (e.g., choosing smaller vehicles that still do the job),
- Retrofitting engines for efficiency and safety (Project Green Fleet),
- Utilizing low carbon fuels (e.g., E85, biodiesel),
- Purchasing new OEM technology (e.g., hybrid, C/LNG, propane, electric),
- Purchasing aftermarket technology (e.g., Auxiliary Power Units (APUs), Plug/Hybrid Electric Vehicle (PHEV) conversion).
- Investing in process efficiencies (e.g., driving fewer miles through route planning), and
- Promoting driver education (e.g., speeding, tire inflation).

Private fleet reductions will need to be measured in two broad categories: total fleet GHG emissions from fuel combustion and normalized GHG statistics (e.g., GHG per mile, GHG per vehicle). This would ensure that companies whose overall emissions may be increasing due to business growth can still participate by enabling a growing fleet to operate more efficiently.

As lead-by-example, the state-owned fleet should immediately start working toward the 2025 goal of a 25% reduction of GHG emissions. (See also Cross-Cutting CC-3, State Lead-by-Example.)

Timing: Immediate; many of these projects are ongoing and will be expanded in the near future.

Parties Involved: Minnesota Environmental Initiative (Project Green Fleet and Clean Air Minnesota) and multiple public and private funders and partners; Minnesota Trucking Association; Minnesota Chamber of Commerce; Minnesota Center for Environmental Advocacy; GE Fleet Services; MPCA; EPA SmartWay Program; Hennepin County; Minnesota Regional Railroad Association; Midwest Clean Diesel Initiative; Minnesota Climate Registry.

Other: Idle reduction activities in other areas of the country have shown that drivers can safely cut idling time by approximately 15 minutes per day through the use of idle reduction techniques. Based on this information, and average fuel use data from the U.S. Environmental Protection Agency,[44] 15 minutes of idle reduction per day on 500 school buses could result in diesel fuel savings of over 11,000 gallons per year, or more than 900 gallons per month. Fuel savings can be higher when training and awareness are coupled with data logging and reporting activities.

Currently available technologies, such as anti-idle equipment, newer and more efficient locomotive engines, and hybrid equipment can add significantly to engine owners' capital improvement costs. For example, in rail operations, smaller locomotive operators may lack capital to invest in these technologies even though future fuel savings would make them cost-effective. Other added costs may not contribute to increased return on capital and thus may only be weighed as public priorities to the extent they are valued for their emission reduction potential. Likewise, investments in future technologies such as fully-electric equipment and facilities, require a distinct public commitment to funding emission reductions from hydrocarbon-based fuels.

Implementation Mechanisms

Establish a state Fleet Efficiency Consortium sponsored by the Department of Transportation, MPCA, and/or Commerce. This Consortium would comprise volunteer businesses with vehicle fleets as well as state and additional resources with fleet efficiency expertise. The Consortium would select a methodology for calculating and tracking mobile GHG emissions that would be standardized among participating fleets. Headcount and overhead cost for the Consortium from the public sector will need to be estimated.

Create a source of funds that supports existing successful voluntary GHG reduction efforts at fleets (e.g., Project Green Fleet, MPCA APU Project, MPCA Small Business Environmental Improvement Loan Project). See types of programs available for fleet managers in "Types of

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[44] U.S. Environmental Protection Agency. (1998). *Emission Facts, Idling Vehicle Emissions* (EPA Document No. EPA420-F-98-014). Washington, DC: EPA Office of Mobile Sources.

GHG reductions." Amount of funds required will be based on average cost for multiple types of upgrades to various fleet types (e.g., APUs for heavy-duty truck fleets, hybrids for sedan fleets).

Add mobile emissions to the state Climate Registry project to ensure emissions are tracked appropriately and that volunteer businesses are recognized for their efforts.

Methodology: Create a standard methodology to establish baseline processes (CO_2e modeling), selection criteria, emissions reporting standards, and additional requirements for mobile source emission reduction plans.

Use of funds: These programs would continue existing programs and help fund the purchase of lower-emitting fleet vehicles, such as HEVs, as well as investments in aftermarket technology such as diesel retrofits, PHEV conversions, and APUs.

State Liaison: Create a set of standards to administer funding program. Management would include application and selection process for grants as well as recognition programs and best practices.

Related Policies/Programs in Place

Project Green Fleet (PGF) is the primary Minnesota collaborative for voluntary, diesel and mobile source emission-reduction projects. PGF currently works with dozens of school districts, the MPCA, the Minnesota Departments of Health and Education, Laidlaw, First Student, bus operator associations, tribes, private school bus and diesel fleet owners, and units of local government.

PGF will have done the following retrofits by the end of 2007:

- More than 500 school buses statewide,
- 41 heavy-duty trucks, and
- 10 transit buses.

PGF uses only EPA and/or CARB verified technology. Depending upon the combination, each retrofit will guarantee a minimum emission reduction of between 25% and 50%, depending upon the pollutant.

Idle Reduction Program: The MPCA, in cooperation with the US EPA, offers loans to help small trucking companies pay for idle reduction devices such as auxiliary power units. This equipment can reduce fuel consumption by 75%, which conserves resources, helps achieve energy independence, and reduces the emissions that contribute to soot and smog. During 2006, 30 loans were issued ranging from $7,500 to a maximum of $50,000. However, these funds are limited and the program's definition of "small business" for the purposes of the loan availability is prohibitive. http://www.pca.state.mn.us/programs/sbomb_loan.html

EPA Smartway Transportation Partnership (http://www.epa.gov/otaq/smartway/idlingtechnologies.htm#truck-mobile).

Many private truck stops have electrification or window mounted climate control units available. Advertising those locations may generate greater use.

Examples need to be quantified in terms of number of fleets impacted, number vehicles impacted (already done for PGF), capital cost, and annual GHG benefits (actual and expected).

Type(s) of GHG Reductions

Vehicles have broad GHG impacts. From the combustion of fuel, carbon dioxide, nitrous oxide, methane, ozone precursors, and black carbon are released. In addition, during the operation of air conditioning units, HFCs are released.

A recent U.S. House of Representatives committee reported that black carbon's contribution to climate change is second only to carbon dioxide.[45] Black carbon, or soot, results from the incomplete combustion of fossil fuels. While black carbon absorbs heat when airborne, it stays in the atmosphere for a relatively short period of time and mitigating such emissions would provide immediate climate change and health benefits.

Estimated GHG Reductions and Net Costs or Cost Savings

At a minimum, with the equipment currently used in PGF, for every 100 buses retrofitted the estimated emission reductions are CO_2, 860 lbs.; PM2.5, 120 lbs.; and volatile organic compounds (VOCs), 620 lbs. The emission and exposure reductions will be tracked over at least a 5-year period. (Source: Minnesota Environmental Initiative and MPCA.)

As an estimate, for 500 school buses, fuel savings of 11,250 gallons per year, or 937 gallons per month, are based on average reported idle reductions achieved in other areas of the country and vehicle fuel use and emissions data provided by the US EPA. Idle reduction activities, which include anti-idling policies and driver training, have shown that drivers can safely cut idling time by approximately 15 minutes per day through the use of idle reduction techniques.[46] US EPA data shows that diesel-powered buses use approximately 0.5 gallons of fuel per hour when idling.[47] Assuming that school buses operate 180 days of the year, 15 minutes of idle reduction on 500 school buses results in fuel savings of 11,250 gallons per year, or 938 gallons per month. Fuel savings can be higher when training and awareness are coupled with data logging and reporting activities (Table H-8).

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[45] U.S. House of Representatives, Committee on Oversight and Government Reform, October 18, 2007.

[46] Estimate from Massachusetts Department of Environmental Protection, May 6, 2006.

[47] U.S. Environmental Protection Agency. (1998). *Emission Facts, Idling Vehicle Emissions* (EPA Document No. EPA420-F-98-014). Washington, D.C: EPA Office of Mobile Sources.

Table H-8. Estimated fuel and GHG reductions from TLU-12

Assumptions						
Private	**MPG**	**Annual Mileage**	**Annual Gallons of Fuel**	**Annual Average $MtCO_2$ Per Vehicle**	**Annual $MtCO_2$ Per Class (subtotals)**	**Average Annual Improvement**
3,353,858 sedans	24.6	25,000	1,016	9	30,732,202	5%
883,623 pickup trucks	18.4	25,000	1,359	12	10,825,135	5%
147,800 commercial trucks	8.8	50,000	5,682	51	7,571,917	7%
50,000 heavy-duty	5.7	100,000	17,544	182	9,116,474	7%
						6%
10% in private fleets						
Calculations						
58,245,728 = total $MtCO_2$						
5,824,573 = fleet-specific $MtCO_2$						
349,474 = $MtCO_2$ yield at 5% reduction per year						

MPG = miles per gallon; $MtCO_2$ = metric tons of carbon dioxide.

Key Uncertainties

None cited.

Additional Benefits and Costs

Estimates indicate that PGF's early efforts will directly reduce emissions exposure for approximately 30,000 school children statewide. Given the goal in this Option of doubling current programs, would reduce direct emissions exposure for another 30,000 school children.

If Minnesota continues to experience poor air quality, it could be designated as a non-attainment area for ground-level ozone or fine particulate matter. A 1998 Minnesota Chamber of Commerce study estimates that it would cost Minnesota businesses $189 to $266 million annually to comply with regulatory requirements associated with non-attainment for ground level ozone. Other significant restrictions, such as loss of federal transportation funding and limits on expansion, affect businesses in non-attainment regions. This program will help Minnesota avoid that designation.

Mobile source emission-reduction options gained greater relevance to climate change with the release of a study recently in the journal *Nature*. The study points out the significance of ground-level ozone levels to climate change improvement activities. Mobile sources are one of the primary sources of ground-level ozone precursors. According to the study, "Ozone could be twice as important as we previously thought as a driver of climate change." The study reports that "ozone near the ground damages plants, reducing their ability to mop up carbon dioxide from the atmosphere."[48]

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[48] S. Sitch, P. M. Cox, W. J. Collins & C. Huntingford. Indirect radiative forcing of climate change through ozone effects on the land-carbon sink. *Nature* 448, 791-794 (16 August 2007). http://www.nature.com/nature/journal/v448/n7155/full/nature06059.html

Feasibility Issues

None cited.

Status of Group Approval

Approved

Level of Group Support

Unanimous

Barriers to Consensus

None

TLU-13. Reduce Maximum Speed Limits

Policy Description

Reduce maximum speed limits on highways in Minnesota to improve fuel economy and reduce GHG emissions per mile traveled.

Policy Design

Goals: Reduce maximum speed limit on urban interstates to 55 mph (from the current 65 mph) and to 60 mph on rural interstates (from the current 70 mph). Speed limits will be 55 mph on highways not specified by statute (same as today). This strategy reduces GHG emissions per mile traveled but does not reduce VMT.

Timing: Change law during 2008 legislative session with an effective date of January 1, 2009, so that there is enough time to educate the public about the change.

Parties Involved: Highway users, MnDOT, Minnesota State Patrol, local law enforcement.

Other: None.

Notes: The speed a vehicle is driven has a major impact on fuel economy. While each vehicle reaches its optimal fuel economy at a different speed (or range of speeds), gas mileage usually decreases rapidly at speeds above 55 to 60 mph according to the US EPA and the US Department of Commerce.

Implementation Mechanisms

Would require increased enforcement so cost for state and local law enforcement would be required.

Should ask MnDOT for a cost estimate for the change over signs and educational materials for the current higher speed limits.

Related Policies/Programs in Place

Speed limits are currently 55 mph on urban interstates and 65 mph on rural interstates in nine states (Alaska, Connecticut, Delaware, Illinois, New Jersey, Oregon, Pennsylvania, Rhode Island, and Vermont.) The only state that specifies 60 mph for a rural interstate is Hawaii.

Type(s) of GHG Reductions

Primarily CO_2.

Estimated GHG Reductions and Net Costs or Cost Savings

Quantification Methods:

Calculate difference in fuel and time from:

Diesels: 70 mph at ~6 mpg to 60 mph at ~7 mpg
Gasoline vehicles: 70 mph at ~26 mpg to 60 mph at ~30 mpg

Value for the cost of time:

Diesels: $25.53
Gasoline vehicles: $14.76/hour

Basis: National after-tax wage rate.

Data Sources:

U.S. Department of Labor, Bureau of Labor Statistics, “Establishment Data; Hours and Earnings,” Table B-14 and “Employer Costs for Employee Compensation-December 2005,” Table 10.

U.S. Environmental Protection Agency, Office of Transportation and Air Quality, Smartway Transport Partnership, “A Glance at Clean Freight Strategies: Reducing Highway Speed,” EPA420-F-04-007, February 2004.

U.S. Environmental Protection Agency, Office of Transportation and Air Quality, MOBILE6 model, documented in “User’s Guide to MOBILE6.1 and MOBILE6.2: Mobile Source Emission Factor Model,” EPA420-R-03-010, August 2003.

Jeffrey Ang-Olson and William Schroeer, “Energy Efficiency Strategies for Freight Trucking: Potential Impact on Fuel Use and Greenhouse Gas Emissions,” *Transportation Research Record 1815*, Transportation Research Board of the National Academy of Sciences, Washington, DC, 2002.

Quantification Methods:

Fuel Savings: The diesel fuel consumption from Class 8 diesel trucks was multiplied by 60% (low) or 80% (high) to account for the amount of fuel consumed at speeds above 60 mph from 2008 through 2014. Starting in 2015, the speed for Class 8 trucks was reduced to 55 mph. This fuel consumption was then multiplied by 50% to account for the expected penetration rate of this measure. This quantity was then multiplied by the percentage increase in fuel economy. The ratio of reduction in fuel consumption was then multiplied by the baseline CO_2 emissions to estimate the reduction in CO_2 from this measure. Fuel cost savings were calculated by multiplying the per unit fuel cost by the number of gallons reduced.

Increased Driving Time: This was estimated as the product of the increased time required for traveling the same distances at 60 mph (prior to 2015) or 55 mph (2015 and later) rather than 70 mph multiplied by the hourly trucking industry cost.

Same process for automobiles.

Key Assumptions: 60% to 80% of Class 8 diesel truck travel (fuel consumption) is spent at speeds above 60 mph, assumed to be at 70 mph on average. Fifty percent of this truck travel is assumed to be reduced to 60 mph or 55 mph (Ang-Olson and Schroeer).

Each one mile per hour reduction of speed from 70 mph to 55 mph yields a fuel economy increase of 0.1 miles per gallon (EPA) for heavy-duty diesel trucks.

Average hourly truck transportation wage is $17.22/hour (BLS), with an industry average overhead rate of 1.48 (BLS).

Base fuel economy assumed to be 6.42 mpg (EPA MOBILE6 model); assumed to increase to 7.42 mph with this measure.

Reductions
Upon adoption:

- Strict adherence to 65 mph: 210,000 metric tons annually (gas savings of $79 million)
- Strict adherence to 60 mph: 400,000 metric tons annually (gas savings of $158 million)
- Strict adherence to 55 mph: 570,000 metric tons annually (gas savings of $238 million)

Year 2020:

- Strict adherence to 65 mph: 250,000 metric tons annually (gas savings of $94 million)
- Strict adherence to 60 mph: 470,000 metric tons annually (gas savings of $187 million)
- Strict adherence to 55 mph: 680,000 metric tons annually (gas savings of $281 million)

Values for 60 mph used in summary table.

Estimated Costs: Administrative costs for strict enforcement are likely to be offset by revenues from fines. Savings in gasoline costs will accrue to motorists.

Key Uncertainties

The ability to enforce a speed limit significantly lower than current policy is uncertain.

Additional Benefits and Costs

A significant additional benefit of lowering speed limits is reduced injuries and fatalities. The Canada Safety Council[49] states that “As speed increases over 100 km/h (60 mph), the fatality rate of vehicle occupants goes up exponentially. For example, the chances of being killed in a vehicle traveling at 120 km/h (72 mph) are four times higher than at 100 km/h (60 mph).”

The Canada Safety Council also notes that “a recent study examined the impact of higher travel speeds on US rural interstates after the repeal in November 1995 of the national speed limit. Researchers found states that had increased their speed limits to 75 mph (120 km/h) experienced a shocking 38 per cent increase in deaths per million vehicle miles than expected, compared to

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[49] http://www.safety-council.org/

deaths in those states that did not change their speed limits. States that increased speed limits to 70 mph (112 km/h) showed a 35% increase in fatalities."

In 2006, 494 people died in vehicle crashes in Minnesota, 35,025 were injured, and the economic cost was $1.5 billion (rounded).[50]

Lower speeds will also reduce local air emissions and air pollution. See Mullen, M A; Wilson Jr, J H; Gottsman, L ; Noland, R B; Schroeer, W L, "Emissions Impact of Eliminating National Speed Limits: One Year Later", *Transportation Research Record No. 1587, Effects of Transportation on Energy and Air Quality*, 1997,[51] which states:

> The National Highway System (NHS) bill passed by Congress in November 1995 eliminated the national maximum speed limit. It has allowed states to set their own speed limits, which many have changed during the past year. This analysis examines the impact of speed limit changes 1 year after passage of the NHS. Oxides of nitrogen (NO_x), carbon monoxide, and volatile organic compounds are analyzed and are found to have increased nationwide by up to 6%, 7%, and 2%, respectively. Much of the increase has occurred in western states, which generally have increased vehicle speeds more than in eastern and midwestern states. For example, in Texas NOx emissions are estimated to have increased by 35% due to large increases in highway and arterial speed limits.

Feasibility Issues

Will require enforcement.

Status of Group Approval

Approved

Level of Group Support

Majority

Barriers to Consensus

Concerns included ability to enforce, potential for non-compliance even with increased enforcement, and impact on travel times.

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[50] Minnesota Motor Vehicle Crash Facts 2006, published by the Minnesota Department of Public Safety, Office of Traffic Safety, page ii.

[51] http://pubsindex.trb.org/document/view/default.asp?lbid=474594

TLU-14 Freight Mode Shifts: Intermodal and Rail

Policy Description

Transportation of freight by railroad generally results in less fuel use and GHG emissions than transportation by truck. This option would support the expansion of intermodal rail service for Minnesota shippers through public/private partnerships. In addition, the state would strive to increase the competitiveness of rail rates for all Minnesota shippers.

Develop public/private partnerships to support mode shifts to rail, and decrease truck VMT relative to the baseline. This strategy accounts for part of the VMT reduction goal of TLU Area 1.

Policy Design

Improved rail service and the ability of the rail system to meet future demand *implicitly* leads to system-wide greenhouse gas reductions by shifting projected freight and passengers to rail or by preventing a shift to a less efficient mode. Improvements to the rail system or associated equipment can also have *direct* impacts on greenhouse gas emissions. Locomotive idling produces significant emissions and can be mitigated by reducing system congestion and choke points and by using improved technology.

Goals

Goals: As the population of Minnesota and the world increases, so does the volume of freight. The ten year freight forecast indicates a 25% increase in total freight by 2017. Moving goods in the most economical way is an essential component of our economy and lives. Additionally, seeking policies that balance the need for GHG reduction and consumer affordability will best serve our future.

The TWG highlights for the MCCAG the importance of the freight sector, especially given its rapid growth. MnDOT has in progress a statewide freight plan. The MCCAG is not yet ready to develop its own emissions reduction targets, but recommends that the in-progress study ensure that its goals include a substantial freight mode shift towards growth in rail freight, and explicitly address the GHG emissions implications of its Freight Plan, with respect to the Governor's GHG commitments.

- Decrease inefficiencies and limitations in the existing Minnesota rail network and increase overall capacity by reducing system congestion, bottlenecks, and chokepoints.
- Prevent modal shift of freight from rail to truck due to lack of capacity. Maximize the amount of freight that can be moved by rail in order to sustain projected growth in domestic and international goods movement in the state.

Timing: Policy implementation should commence during the 2008 legislative season.

Parties Involved: MnDOT, Minnesota Chamber of Commerce, Minnesota Regional Railroad Association, Minnesota Trucking Associations

Other: None.

Implementation Mechanisms

- Create more effective freight transition between modes at intermodal yards, ports and airports.
- Establish tax credits for rail expansion/preservation.
- Direct MnDOT to preserve existing corridors and consider new regional rail options in the State Transportation Infrastructure Plan (STIP).

Related Policies/Programs in Place

The Minnesota PCA small business environmental low-interest loan program has been made available to trucking companies, however funds are very limited and the PCA definition of small business for the purposes of the loan is very prohibitive.

Many private truck stops have electrification or window mounted climate control units available. Advertising those locations by mapping them at public rest stops may generate greater use.

Various EPA funding programs.

Grant aids allocated in the Federal energy bill. Section 1112 of the bill sets aside $200M for short-line (class II and III) rail improvements.

Type(s) of GHG Reductions

Primarily CO_2 emissions.

Estimated GHG Savings and Costs per $MtCO_2e$

Data Sources: None.

Quantification Methods: None.

Key Assumptions: None.

Key Uncertainties

None cited.

Additional Benefits and Costs

By shifting freight from truck to rail, this option could result in small additional benefits related to highway congestion and highway safety.

Feasibility Issues

The success of this strategy depends on sufficient shipper demand and willingness of the railroads to provide intermodal service. These factors are largely outside government control.

Status of Group Approval

Approved

Level of Group Support

Super Majority

Barriers to Consensus

Concern about lack of specificity.

Appendix I
Agriculture, Forestry, and Waste Management Policy Recommendations

Summary List of MCAAG Recommendations

Policy No.	Policy Recommendation	GHG Reductions (MMtCO$_2$e)			Net Present Value 2008–2025 (Million $)	Cost-Effective-ness ($/tCO$_2$e)	Level of Support
		2015	2025	Total 2008–2025			
AFW-1	Agricultural Crop Management						Unanimous
	A. Soil Carbon Management	0.72	1.3	15	–$34	–$2	
	B. Nutrient Management	0.79	1.3	15	–$543	–$37	
AFW-2	Land-Use Management Approaches for Protection and Enrichment of Soil Carbon						Unanimous
	A. Preserve Land	0.15	0.44	3.7	$120	$33	
	B. Reinvest in Minnesota–Clean Energy (RIM-CE)	0.09	0.19	1.8	$59	$34	
	C. Protection of Peatlands & Wetlands	*Not quantified*					
AFW-3	In-State Liquid Biofuels Production						Super Majority (4 objections)
	A. Ethanol Carbon Content	1.8	2.2	27	–$242	–$9	
	B. Fossil Diesel Displacement	0.03	0.19	1.4	$74	$55	
	C. Gasoline Displacement	2.8	9.1	73	$336	$5	
AFW-4	Expanded Use of Biomass Feedstocks for Electricity, Heat, or Steam Production	1.3	3.8	31	$102	$3	Unanimous
AFW-5	Forestry Management Programs To Enhance GHG Benefits						Unanimous
	A. Forestation	0.55	2.2	17	$218	$13	
	B. Urban Forestry	1.2	2.7	26	–$295	–$12	
	C. Wildfire Reduction	*Not quantified*					
	D. Restocking	2.1	8.4	65	$2,187	$33	
	E. Forest Health and Enhanced Sequestration	*Not quantified*					
AFW-6	Forest Protection—Reduced Clearing and Conversion to Non-Forest Cover	2.2	2.7	34	$101	$3	Unanimous
AFW-7	Front-End Waste Management Technologies						Unanimous
	A. Source Reduction	0	3.6	20	$59	$3	
	B. Recycling	3.1	3.4	45	–$207	–$5	
	C. Composting	0.29	0.41	4.9	$137	$28	
AFW-8	End-of-Life Waste Management Practices						Unanimous
	A. Landfilled Waste Methane	0.07	0.73	4.4	$5.7	$1	
	B. Residuals Management	0.52	0.63	8.1	$650	$80	
	C. WTE Processing	0.37	0.84	7.9	$257	$32	
	Sector Total After Adjusting for Overlaps*	**13.2**	**29.5**	**279**	**$2,090**	**$7**	
	Reductions From Recent Actions	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	
	Sector Total Plus Recent Actions	**13.2**	**29.5**	**279**	**$2,090**	**$7**	

GHG = greenhouse gas; MMtCO$_2$e = million metric tons of carbon dioxide equivalent; $/tCO$_2$e = dollars per metric ton of carbon dioxide equivalent; WTE = waste to energy.

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

*Overlaps include an assumed 100% overlap of AFW-3b&3c with TLU-3 (reductions excluded from AFW totals); an assumed 100% overlap of AFW-4 with ES-5 (reductions and costs excluded from AFW totals); overlap of AFW-7&8 (incremental benefits and costs of AFW-8 included in the AFW totals).

Assessment of Available Biomass Resources in Minnesota

Table I-1 is presented below to provide an assessment of the availability of biomass resources in Minnesota to satisfy the various demands of the recommended policies. It summarizes the biomass supply and demand for the Minnesota Climate Change Advisory Group (MCCAG) process. The amount of biomass available was obtained using the Minnesota Center for Energy and Environment's BioPower Evaluation Tool (BioPET),[1] while the demand requirements are based on the assessments of energy requirements from each Agriculture, Forestry, and Waste Management (AFW) policy. Based on this initial assessment, Table I-1 shows that Minnesota has sufficient biomass resources to meet the MCCAG biomass policy recommendations, although the margin is declining throughout the policy period. Additional analysis and discussion are available under the relevant sections of AFW-3 and AFW-4.

Table I-1. MCCAG policies: biomass supply and demand assessment

Biomass Resource	Dry Tons Available per Year		Notes
	2015	2025	
Supply			
Hay/straw non-CRP	2,321,987	2,321,987	From the Minnesota Center for Energy and Environment's BioPET
Switchgrass/other	1,007,905	1,007,905	From the Minnesota Center for Energy and Environment's BioPET
Corn stalk	21,680,081	21,680,081	From the Minnesota Center for Energy and Environment's BioPET
Sunflower stalk	45,846	45,846	From the Minnesota Center for Energy and Environment's BioPET
Hay/straw from CRP lands	1,955,457	1,955,457	From the Minnesota Center for Energy and Environment's BioPET
Unprocessed logging residues	1,016,359	1,016,359	From the Minnesota Center for Energy and Environment's BioPET
Mill residues	595,099	595,099	From the Minnesota Center for Energy and Environment's BioPET
Total Supply (BioPET)	28,622,735	28,622,735	From the Minnesota Center for Energy and Environment's BioPET
Energy Crop Production Goal (Additional Biomass)	224,000	672,000	Energy Crop Production Goal: By 2015 have 40,000 acres of land producing high-MMBtu and ecologically sustainable energy crops near energy facilities. By 2025 have 120,000 acres of these crops in production.
BioPET Supply Plus Additional Energy Crop	**28,846,735**	**29,294,735**	

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[1] The Center for Energy and Environment's BioPET software is an Excel database that contains information on the biomass available at the county level.

Policy Requiring Biomass	Dry Tons Required		Notes
	2015	2025	
Approximate Demand			
BAU Biomass Requirements	1,443,645	2,274,963	Based on analysis by the Energy Supply/Residential Commercial, and Industrial ES/RCI TWG. Recent statutes regarding the Conservation Improvement Program (CIP) and Renewable Energy Standard (RES) are not included, because both of these are considered mitigation options in the process and are incorporated under the relevant ES/RCI policy. The biomass reference case estimates 22,382 billion Btu's in 2015 and 35,271 billion Btu's in 2025, and assumes 7,752 Btu's/dry lb (average of Minnesota feedstocks from BioPET).
AFW-3 In-State Liquid Biofuels Production (Gasoline Displacement)	8,144,221	21,523,760	Assumes gasoline displacement by cellulosic ethanol or equivalent. Dry tons required are based on conversion rates of biomass to ethanol—90 gallons/ton in 2015 and 100 gallons/ton in 2025. Based on the full (50% in 2025) gasoline displacement goal in AFW-3.
AFW-4 Expanded Use of Biomass Feedstocks for Electricity, Heat, or Steam Production	Biomass required incorporated under ES/RCI policies, below	Biomass required incorporated under ES/RCI policies, below	Policy targets are 16 trillion Btu's in 2015 and 46 trillion Btu's in 2025.
ES-3 Efficiency Improvements, Repowering, and Other Upgrades to Existing Plants (Biomass Co-firing)	1,225,588	2,090,917	Policy targets are 19 trillion Btu's in 2015 and 32.4 trillion Btu's in 2025. Assumes 7,752 Btu's/dry lb.
ES-5 Renewable Electricity Standard (RES)	435,299	939,136	Policy targets are 6.7 trillion Btu's in 2015 and 14.6 trillion Btu's in 2025. Assumes 7,752 Btu's/dry lb.
RCI-4 Combined Heat and Power (CHP)	111,413	694,893	Policy targets are 1.7 trillion Btu's in 2015 and 10.8 trillion Btu's in 2025. Assumes 7,752 Btu's/dry lb.
Total Demand	**11,360,165**	**27,523,669**	
Biomass Balance			
Remaining Dry Tons	**17,486,570**	**1,771,066**	

BAU = business as usual; CRP = [USDA's] Conservation Reserve Program; MMBtu = million British thermal units; TWG = Technical Work Group.

Other studies have indicated biomass availability similar to the numbers obtained through BioPET. As a comparison, the biomass estimates from BioPET are displayed in Table I-2, along with estimates from other studies. Note that no additional forest biomass is assumed to be available (outside of logging debris and mill residue), although new forest policies, such as AFW-5c (Wildfire Reduction), could produce additional biomass as part of forest-thinning projects. It is also worth noting that none of the above estimates includes biomass from the municipal solid waste stream. These sources could include biomass from urban tree maintenance programs, lawn/garden waste, waste wood, paper, and other waste fiber.

Although initial assessments of Table I-1 show sufficient resources to meet the MCCAG's biomass policies, a number of variables are not taken into consideration, including:

- The numbers presented assume that all land that is currently available for biomass will still be available in 2015 and 2025, and that all available biomass is actually collected.
- Hay and straw on non-Conservation Reserve Program (CRP) acreage serve other purposes, including feed and bedding for livestock.
- The technology and process to harvest, and the transportation and storage logistics associated with corn stalk usage for biomass, are still in the developmental stages.
- Currently, haying and grazing on CRP land can only occur under certain conditions: managed haying can only occur one out of every three years after the CRP cover is fully established, and acreage either hayed or grazed under managed or emergency provisions in either of the previous two years is ineligible for managed haying or grazing in the current year (http://www.fsa.usda.gov/FSA/webapp?area=home&subject=copr&topic=crp-eg).
- Weather conditions, including flood and drought, also play a vital role in the actual availability of biomass.

Finally, an important assumption requiring further analysis is whether the biomass resources summarized above can be produced sustainably over the long term. For example, additional study is needed on the amount of crop residue that needs to be left on the field to support soil carbon and nutrient levels. Some studies, such as the U.S. Department of Energy's (DOE's) National Renewable Energy Laboratory's (NREL's) study cited in Table I-2, assume that 30% of the crop residue is left on the field.

Table I-2. Comparison of studies estimating biomass availability

Source of Data	Estimated Biomass Availability (Dry Tons per Year)	Reference
BioPET	28,622,735	From the Minnesota Center for Energy and Environment's BioPET
ORNL 1999 Database	21,247,327	Biomass resources from Oak Ridge National Laboratory (ORNL) 1999 database: http://bioenergy.ornl.gov/resourcedata. Taken from: *Minnesota Biomass—Hydrogen and Electricity Generation Potential*—A study by the National Renewable Energy Laboratory (NREL), Golden, Colorado, February 2005.
NREL Geographic Information System (GIS) Group	41,727,215	Biomass resources from NREL GIS Group database, updated with new sources of data: mill residue data are from the 2002 Timber Products Output Database by the U.S. Department of Agriculture (USDA) Forest Service; agricultural residue data are from USDA's National Agricultural Statistics Service: http://www.nass.usda.gov:81/ipedb/. Taken from: *Minnesota Biomass—Hydrogen and Electricity Generation Potential*—A study by NREL, Golden, Colorado, February 2005.
1997 Institute for Local Self-Reliance (ILSR) Inventory	22,612,398	Biomass resources from 1997 ILSR Inventory. Taken from: *Minnesota Biomass—Hydrogen and Electricity Generation Potential—A study by the NREL,* Golden, Colorado, February 2005.

AFW-1. Agricultural Crop Management

Policy Description

This policy recommendation addresses both agricultural soil carbon management, as well as nutrient management to achieve greenhouse gas (GHG) benefits. For soil carbon management, conservation-oriented management of agricultural lands, cropping systems, crop management, and agricultural practices may regulate the net flux of carbon dioxide (CO_2) from soil. Each farm operation and each field management unit has unique traits that may allow management practices to influence nutrient, water, and carbon cycling and sequestration. Defining GHG outcomes based upon management indices may allow farmers to incorporate management practices within their specific operational needs to meet desired GHG goals. Providing cropping and management flexibility within each field or tract management unit allows both production and resource management goals to be transparent and readily valued.

The efficient use of agricultural fertilizer, both commercial and animal-based, can be improved through certain management practices and systems. An example is overapplication of nitrogen, which can result in plants not fully metabolizing the nitrogen, allowing the nitrogen to leach into groundwater and/or be emitted to the atmosphere as nitrous oxide (N_2O). Better nutrient utilization can lead to lower N_2O emissions from runoff. An example is tile drainage systems that use the latest technology and design models to reduce nitrates leaching into surface water and groundwater.

Policy Design

Goals:

Soil Carbon Management—Adopt no-till, strip-till, and other conservation farming practices that provide enhanced ground cover, or other cropping management practices that achieve similar soil carbon benefits, for 33% of all annual crop production in Minnesota by 2025.

Nutrient Management—Increase fertilizer application efficiency by 50% by 2025.

Timing:

Soil Carbon Management—By 2015, adopt no-till, strip-till, or other conservation farming practices that reduce GHG emissions and increase soil carbon sequestration for 15% of all annual crop production in Minnesota, or manage cropping systems to achieve similar outcomes. By 2025, achieve the full 33% goal.

Nutrient Management—By 2015, increase fertilizer application efficiency by 25%, and achieve the full goal by 2025.

Parties Involved: Minnesota Association of Soil and Water Conservation Districts (SWCD),[2] U.S. Department of Agriculture's (USDA's) Natural Resources Conservation Service (NRCS),

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[2] A nonprofit organization representing Minnesota's 91 soil and water conservation districts.

Minnesota Department of Agriculture (MDA), University of Minnesota, USDA's Farm Service Agency (FSA),[3] and agricultural organizations.

Other: Research will be needed to help farmers effectively convert current farming practices to no-till, strip-till, or other conservation farming practices. These practices will reduce GHG emissions and increase soil carbon sequestration. Research will be needed to develop methods to efficiently and effectively determine outcomes.

Research will be needed to speed adoption of Global Positioning System-based technologies and to develop outcome- and performance-based methods. Research will be needed to determine the best management practices (BMPs) of animal- and commercial-based fertilizers. Encouraging incorporation of livestock manure to reduce GHG emissions and possible runoff issues is an example of BMPs for livestock producers. Manure incorporation is generally required under most confinement livestock permits.

Incentives for these desired farming practices may be necessary, but the amount and type of incentives are not known at this time. Some practice changes require education, rather than financial incentives. To the extent that GHG targets are based on outcome, rather than prescription, financial incentives may be unnecessary.[4]

The type of conservation practice adopted under the goal is not prescriptive. This policy will strive to quantify cropping systems' net effect on GHG emissions, rather than only focus on individual conservation practices and activities. Other cropping management/conservation practices that achieve soil carbon benefits similar to conservation tillage are considered to be of equal importance. Land-use crop cover quantification will be considered under AFW-2.

Implementation Mechanisms

- Encourage farmers to adopt voluntary BMPs as developed by the University of Minnesota and promulgated by the Minnesota Agricultural Extension and MDA.
- Encourage farmers to meet outcomes based on existing management indices and ratings, such as the Soil Conditioning Index and the Soil Tillage Intensity Rating. These outcome-based measurements need to be further research and refined (Soil Conditioning Index: http://soils.usda.gov/sqi/management/files/sq_atn_16.pdf, Soil Tillage Intensity Rating: http://www.mandakzerotill.org/books/proceedings/Proceedings%202006/Alan%20Ness%20presentation.htm). Implementing individual practices may have different outcomes on objectives (e.g., reduced GHG emissions, improved water quality, and decreased soil erosion), depending on the type of management system adopted (e.g., soil, cropping, tillage). No-till may not sequester carbon under some scenarios, but may do so under others.
- Develop GHG outcome-based indices to identify the greatest sequestration capacity by individual management field or tract.

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[3] The FSA administers and manages farm commodity, credit, conservation, disaster, and loan programs, as laid out by the U.S. Congress. NRCS also administers conservation programs.

[4] More information about MDA's BMPs can be found at: http://www.mda.state.mn.us/chemicals/fertilizers/nitroch4.htm

- Fund research and development of farming practices and cropping systems that increase carbon input (e.g., reversion to native vegetation, setting aside agricultural land as grassland, improved crop rotations, yield enhancement measures, organic amendments, cover crops, improved irrigation practices) or decrease carbon output (e.g., proper tillage methods), while maintaining crop yield, so that GHG emissions are reduced.
- Fund research into cover crops and carbon sequestered in Minnesota (e.g., cover crops planted after annual row crops or aerial seeding over the top of the growing row crops may sequester more carbon than just no-till or strip-till practices).
- Evaluate and implement economical agricultural practices that maintain a primary income source from crop production or that may become a primary income source from land set-asides.
- Evaluate and implement economical mechanisms that may affect crop choice (e.g., support payments, crop insurance, disaster relief) and farmland preservation (e.g., conservation easement, use-value taxation, agricultural zoning), as incentives to increase the carbon stock of agricultural soil.
- Document the environmental co-benefits of carbon sequestration practices, such as soil fertility, soil buffering capacity, pesticide immobilization, reduced energy for field operation, enhanced water infiltration, prevention of wind and water erosion, and improved fertilizer management.
- Use flexible outcome-based indices (e.g., fertilizer application levels per unit of crop production) rather than practice prescriptions, to allow farmers the ability to use various management methods to achieve GHG targets. Development and implementation of such indices will require investment in research. Utilizing existing outcome-based management indices and further refining management indices should remain at the forefront of these policy recommendations. Providing agriculture with the flexibility to meet production and resource goals is an integral part of the solution. While it can be assumed that agricultural GHG-reducing BMPs will have a positive effect, it will be more cost-effective and climate-effective to calculate the GHG-reduction effect within the variables posed by soils, topography, cropping systems, and even climate. Management indices allow for this.

Related Policies/Programs in Place

The Blue Earth River Basin Initiative ran a project called the Third Crop Initiative, which aims to replace annual crops with perennial crops. Watershed pollution reduction projects aim at many of the practices that also reduce GHG emissions.

Type(s) of GHG Reductions

N_2O: Reductions occur when nitrogen runoff and leaching are reduced, thus decreasing the formation and emission of N_2O.

CO_2: Reductions occur as soil carbon levels in crop soils are increased above business as usual (BAU) levels. Increasing the levels of carbon in soils indirectly sequesters carbon from the atmosphere.

Estimated GHG Reductions and Net Costs or Cost Savings

GHG reduction potential in 2015, 2025 (million metric tons of carbon dioxide equivalent [MMtCO$_2$e]): 1.51, 2.64, respectively *(total includes both the soil carbon and the nutrient management elements).*

Net Cost per tCO$_2$e Reduced: –$20 *(total includes both the soil carbon and the nutrient management elements and represents a cost saving).*

Data Sources:

- Reference abstract: Tristram O. West and Gregg Marland, "Net Carbon Flux From Agriculture: Carbon Emissions, Carbon Sequestration, Crop Yield, and Land-Use Change," *Biogeochemistry* 63(1), April 2003. Available at: links.jstor.org/ sici?sici=0168-2563(200304)63%3A1%3C73%3ANCFFAC%3E2.0.CO%3B2-7
- R.A. Birdsey et al., "North American Forests," in *The First State of the Carbon Cycle Report (SOCCR): The North American Carbon Budget and Implications for the Global Carbon Cycle*, Synthesis and Assessment Product 2.2, ed. Anthony W. King et al., Washington, DC: U.S. Climate Change Science Program and Subcommittee on Global Change Research, March 2007. Available at: http://www.climatescience.gov/Library/ sap/sap2-2/public-review-draft/SOCCR_Chapter11.pdf
- Minnesota Pollution Control Agency and Center for Climate Strategies, "Minnesota Draft Inventory and Forecast. Appendix F. Agriculture," preliminary review draft, July 10, 2007. Available at: http://www.mnclimatechange.us/ewebeditpro/items/O3F12568.pdf
- Quantification of the no-till portion of this policy is based upon 17,985,616 acres of harvested cropland in Minnesota.[5]
- The historical quantity of fertilizer used is consistent with the Agriculture module of the Minnesota draft GHG emissions inventory and reference case projections. This forecast also provides the resulting N_2O emissions and carbon-equivalent emissions. Data regarding the cost savings associated with an increase in the efficiency of fertilizer use are taken from an average of the cost of common fertilizers in April 2007.[6]

Quantification Methods:

Soil Carbon Management

Harvested cropland in Minnesota is estimated at 17,985,616 acres. For the purposes of this analysis, conservation tillage is defined as any system that leaves 50% or more of the soil covered with residue.[7]

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[5] From 2004 Conservation Technology Information Center data, at: http://www.conservationinformation.org

[6] 2007 Fertilizer Use and Cost, at: www.ers.usda.gov/Data/FertilizerUse/Tables/Fert%20Use%20Table%207.xls

[7] The definitions of tillage practices from Conservation Technology Information Center were used under this policy. However, only no-till/strip-till, and ridge-till were considered "conservation tillage" practices. No-till means leaving the residue from last year's crop undisturbed until planting. Strip-till means no more than a third of the row width is disturbed with a coulter, residue manager, or specialized shank that creates a strip; if shanks are used, nutrients may be injected at the same time. Ridge-till means that 4- to 6-inch-high ridges are formed at cultivation. Planters using specialized attachments scrape off the top 2 inches of the ridge before placing the seed in the ground.

Based on the policy design parameters, the schedule for acres to be put into conservation-till/no-till cultivation are shown in Table I-3. These areas are the percentage of cropland required by the policy, less the area currently implementing conservation tillage. For the first 2 years of the analysis (2008–2010), the midpoint sequestration rate of the range provided by the National Farmers Union for the carbon credit program (–0.5 metric tons of carbon per acre [MtC/acre]) was used to estimate the amount of carbon to be sequestered per acre (Minnesota range 0.4–0.6).[8] This program runs until 2010. While it is likely that the program will be extended, at this stage it is unknown. For the remainder of the policy period, the midpoint of the estimated range for carbon sequestration (1 MtC/acre) in agricultural soils was used to estimate the amount of carbon to be sequestered.[9] Based on the Naderman et al. study,[10] it was further assumed that this additional carbon would be sequestered in the soil over 10 years (after 10 years, the crop acres that entered the program were assumed not to store additional carbon). The resulting annual carbon accumulation rate was converted into its CO_2 equivalent, yielding 0.333 $MtCO_2e$/acre/year. To estimate carbon stored each year, the annual accumulation rate was multiplied by the number of acres in the policy program each year.

The estimated cost savings ($2.75/acre) related to the adoption of no-till farming was derived from the low end of the range provided by Walton and Bullen.[11] The reduction in fossil diesel fuel use from the adoption of conservation tillage methods is 3.5 gallons/acre.[12] The life-cycle fossil diesel GHG emission factor of 12.31 $MtCO_2e$/1,000 gallons was used.[13]

Additional GHG savings from reduced fossil fuel consumption were estimated by multiplying the fossil diesel emission factor and diesel fuel reduction per acre estimate provided above. Results are shown in Table I-3, along with a total estimated benefit from both carbon sequestration and fossil fuel reductions.

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[8] From the National Farmers Union Web site: http://www.nfu.org/issues/environment/carbon-credits. See also Chicago Climate Exchange (CCX) Agricultural Soil Carbon Offsets, at: http://www.chicagoclimatex.com/content.jsf?id=781

[9] Mid-point of the range provided by G. Naderman, B.G. Brock, G.B. Reddy, C.W. Raczkowski, “Long Term No-Tillage: Effects on Soil Carbon and Soil Density Within the Prime Crop Root Zone,” 26th Southern Conservation Tillage Conference. See http://www.ag.auburn.edu/auxiliary/nsdl/sctcsa/Proceedings/2004/2004_SCTCSA.pdf

[10] Ibid.

[11] S. Walton and G. Bullen. “Economic Comparison of Three Cotton Tillage Systems in Three North Carolina Regions.” PowerPoint presentation. Raleigh, NC: North Carolina State University. See www.ces.ncsu.edu/depts/agecon/Cotton_Econ/production/Economic_Comparison.ppt, accessed January 2008.

[12] Reduction associated with conservation tillage compared with conventional tillage, at: http://www.ctic.purdue.edu/Core4/CT/CRM/Benefits.html, accessed August 2006.

[13] Life cycle emissions factor for fossil diesel from J. Hill et al., “Environmental, Economic, and Energetic Costs and Benefits of Biodiesel and Ethanol Biofuels,” *Proceedings of the National Academy of Sciences*, 103(30):11206–11210. From the assessment used to evaluate U.S. soybean-based biodiesel life cycle impacts. See http://www.pnas.org/cgi/content/full/103/30/11099

Table I-3. GHG benefits for no-till cultivation

Year	Percentage of Total Cropland in Program	Acres in Program	Acres Still Accumulating Carbon	$MMtCO_2e$ Sequestered	Diesel Saved (1,000 gal)	$MMtCO_2e$ From Diesel Avoided	Total $MMtCO_2e$ Saved
2008	2%	240,629	240,629	0.120	842	0.010	0.131
2009	4%	481,258	481,258	0.241	1,684	0.021	0.261
2010	6%	721,886	721,886	0.361	2,527	0.031	0.392
2011	8%	962,515	962,515	0.320	3,369	0.041	0.362
2012	9%	1,203,144	1,203,144	0.400	4,211	0.052	0.452
2013	11%	1,443,773	1,443,773	0.480	5,053	0.062	0.542
2014	13%	1,684,402	1,684,402	0.560	5,895	0.073	0.633
2015	15%	1,925,030	1,925,030	0.640	6,738	0.083	0.723
2016	17%	2,248,771	2,248,771	0.748	7,871	0.097	0.845
2017	19%	2,572,513	2,572,513	0.856	9,004	0.111	0.967
2018	20%	2,896,254	2,655,625	0.883	10,137	0.125	1.01
2019	22%	3,219,995	2,738,737	0.911	11,270	0.139	1.05
2020	24%	3,543,736	2,821,849	0.939	12,403	0.153	1.09
2021	26%	3,867,477	2,904,962	0.966	13,536	0.167	1.13
2022	28%	4,191,218	2,988,074	0.994	14,669	0.181	1.17
2023	29%	4,514,959	3,071,186	1.02	15,802	0.195	1.22
2024	31%	4,838,700	3,154,299	1.05	16,935	0.208	1.26
2025	33%	5,162,441	3,237,411	1.08	18,069	0.222	1.30

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

Costs savings were estimated by multiplying the estimated savings per acre cited above ($2.75) by the number of acres in the program each year. This savings estimate takes into account budget changes for the cost of fuel, labor, chemicals, and equipment.

The costs of adopting soil management practices (e.g., conservation-till/no-till practices) are based on the financial incentives provided through the Minnesota Agriculture Best Management Practices (AgBMP) program.[14] This program provides farmers a low-interest loan as an incentive to initiate or improve their current tillage practices. The equipment funded is generally specialized tillage or planting implements that leave crop residues covering at least 15%–30% of the ground after planting. The average total cost for this equipment is $23,000, though the average loan for tillage equipment is $16,000. The average-size farm using an AgBMP loan to purchase conservation tillage equipment is 984 acres. Based on the average loan size ($16,000) and the average size of the farm utilizing the loan (984 acres), it is assumed that a once-off loan of $16.26/acre is required to incentivize the adoption of conservation tillage practices. This loan payment was applied to each new acre entering the program to determine an approximate cost of encouraging the use of soil management practices. It was further assumed that carbon credits would be available through future programs similar to the National Farmers Union Carbon

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[14] Minnesota Department of Agriculture (2006), *Agricultural Best Management Practices Loan Program State Revolving Fund Status Report,* St. Paul, MN, February 28, 2006, available at: http://www.mda.state.mn.us/grants/loans/agbmploan.htm

Credit Program[15] or the Iowa Farm Bureau's AgraGate Climate Credits Corporation. The resulting cost-effectiveness of soil carbon management is a cost savings of about \$2/MMtCO$_2$e reduced.

Nutrient Management

An N_2O emission factor for fertilizer use was calculated by dividing the carbon-equivalent emissions from fertilizer use in the Minnesota Inventory and Forecast (I&F) by the fertilizer use for each year. Then, the CO$_2$e emission factors for the years 1990–2002 are averaged to provide an estimated emission factor (5.83×10^{-6} MMtCO$_2$e/ton of nitrogen [N]), which is used to calculate the avoided GHG emissions from the proposed increase in fertilizer efficiency. The results of the calculations detailed in the preceding discussion are displayed in Table I-4. Note that this approach does not capture the avoided life-cycle GHG reductions that would occur through fertilizer efficiency programs (emissions associated with the production, transport, and energy consumption during application).

Historical fertilizer use for Minnesota was obtained from USDA.[16] This figure was extrapolated to obtained BAU fertilizer use figures for the policy period. The target fertilizer efficiency improvements were applied to the inferred fertilizer application rate and multiplied by the number of acres to obtain the fertilizer applied under the policy. The difference between BAU fertilizer applied and fertilizer applied under the policy is the fertilizer reduction target, displayed in Table I-4.

The cost savings associated with using less fertilizer were calculated by multiplying the total fertilizer reduction in each year by the average cost of fertilizer in April 2007.[17] The program costs of nutrient management were estimated as the sum of fertilizer savings (negative cost); costs for soil testing; costs for staff, overhead, and travel; and guidance document preparation costs. Soil testing would be required for each crop field once every 4 years. The cost for each soil test was estimated to be \$10, for a total cost of \$1,577/year for soil testing (assuming \$10 per 75-acre field size).[18] Costs for two additional full-time equivalent (FTE) staff positions, overhead, travel, lab, and associated costs was estimated at \$250,000/year, and preparation of guidance documents was assumed to be \$75,000 in the first year.[19]

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[15] Price of \$2.10 per metric ton of CO$_2$e sourced from CCX Web site on November 13, 2007, available at: http://www.chicagoclimatex.com/

[16] See http://www.ers.usda.gov/Data/FertilizerUse/

[17] 2007 Fertilizer Use and Cost, at: www.ers.usda.gov/Data/FertilizerUse/Tables/Fert%20Use%20Table%207.xls

[18] This is consistent with information supplied by Andy Hart, who indicated that a range of \$7–\$12 is normal, depending on what soil test is applied.

[19] B. Hurd, Northern Minnesota State University Agricultural Economics, personal communication with H. Lindquist, CCS, June 2006.

Table I-4. Fertilizer reduction targets and avoided emissions

Year	Total BAU Fertilizer Use (short tons N)	Policy Target Efficiency Improvements	Target Fertilizer Reduction (short tons N)	Avoided GHG Emissions ($MMtCO_2e$)
2008	661,801	3%	20,055	0.12
2009	663,598	6%	39,035	0.23
2010	665,395	9%	57,034	0.33
2011	667,192	13%	74,132	0.43
2012	668,990	16%	90,404	0.53
2013	670,787	19%	105,914	0.62
2014	672,584	22%	120,720	0.70
2015	674,381	25%	134,876	0.79
2016	676,178	28%	145,842	0.85
2017	677,975	30%	156,456	0.91
2018	679,773	33%	166,737	0.97
2019	681,570	35%	176,703	1.03
2020	683,367	38%	186,373	1.09
2021	685,164	40%	195,761	1.14
2022	686,961	43%	204,883	1.19
2023	688,758	45%	213,753	1.25
2024	690,555	48%	222,382	1.30
2025	692,353	50%	230,784	1.35

BAU = business as usual; N = nitrogen; GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

The total cost-effectiveness of AFW-1 is a cost/savings of \$20/tCO_2e reduced (this includes both the soil carbon and the nutrient management elements). Table I-5 provides a summary of the data used to calculate the program's cost-effectiveness.

Key Assumptions:

Soil carbon management includes all conservation farming practices that reduce GHG emissions and increase soil carbon sequestration. Conservation tillage has been used as an example for quantification purposes, and other options, such as cover crops, different rotations, and perennial crops, are of equal interest.

The analysis assumed carbon sequestration potential is representative across all of the crop systems to which the policy is applied, a 10-year period for accumulating the soil carbon, and no additional significant accumulation of soil carbon after 10 years. This is an important assumption and one where research has developed differences, depending on the carbon measurement used. Additionally, it was assumed that any potential increase in N_2O emissions is not large enough to significantly affect the estimated CO_2 benefits, and cost savings is a representative average of savings to be achieved across all crop systems.

The estimated cost savings related to adopting no-till farming was derived from a study relating to cotton in North Carolina, which may not provide the most appropriate estimate of tillage costs in Minnesota.

BAU fertilizer rates are assumed under historic fertilizer costs. The current explosion in energy and fertilizer costs may substantially alter BAU rates.

Table I-5. Agricultural crop management costs and cost-effectiveness

Year	Total Savings ($MM)	Total Avoided GHG Emissions ($MMtCO_2e$)	Cost of Program ($MM)	Net Cost of Program ($MM)	Discounted Cost ($MM)	Cost-Effectiveness
2008	–$8.6	0.248	$5.72	–$-2.93	–$2.79	
2009	–$16.9	0.489	$5.65	–$-11.24	–$10.19	
2010	–$24.7	0.725	$5.65	–$-19.10	–$16.50	
2011	–$-31.9	0.794	$5.65	–$-26.27	–$21.61	
2012	–$39.0	0.979	$5.65	$-33.38	–$26.15	
2013	–$45.8	1.16	$5.65	–$-40.20	–$30.00	
2014	–$52.4	1.34	$5.65	–$-46.74	–$33.22	
2015	–$58.7	1.51	$5.65	–$-53.04	–$35.90	
2016	–$64.0	1.70	$7.00	–$-57.05	–$36.78	
2017	–$-69.3	1.88	$7.00	–$-62.28	–$38.23	
2018	–$-74.2	1.98	$7.00	–$-67.21	–$39.30	
2019	–$79.0	2.08	$7.00	–$-72.02	–$40.10	
2020	–$83.7	2.18	$7.00	–$-76.72	–$40.69	
2021	–$-88.3	2.27	$7.00	–$-81.31	–$41.07	
2022	–$-92.8	2.37	$7.00	–$-85.79	–$41.27	
2023	–$-97.2	2.46	$7.00	–$-90.18	–$41.31	
2024	–$-101.5	2.55	$7.00	–$-94.48	–$41.22	
2025	–$-105.7	2.64	$7.00	–$-98.69	–$41.01	
Total		**29.4**			**–$577**	**–$19.7**

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

Key Uncertainties

Key uncertainties surround the potential GHG benefits associated with no-till and conservation tillage practices compared with conventional tillage practices. The soil sequestration rates associated with land management practices, including conservation tillage, remain extremely uncertain, and studies highlight this uncertainty. In Figure 1, Manley et al. [20] suggest that determining the level of carbon being sequestered is difficult, and further research is required to clarify this issue to complement and build on the research conducted by the USDA National Soil Tilth Laboratory.[21]

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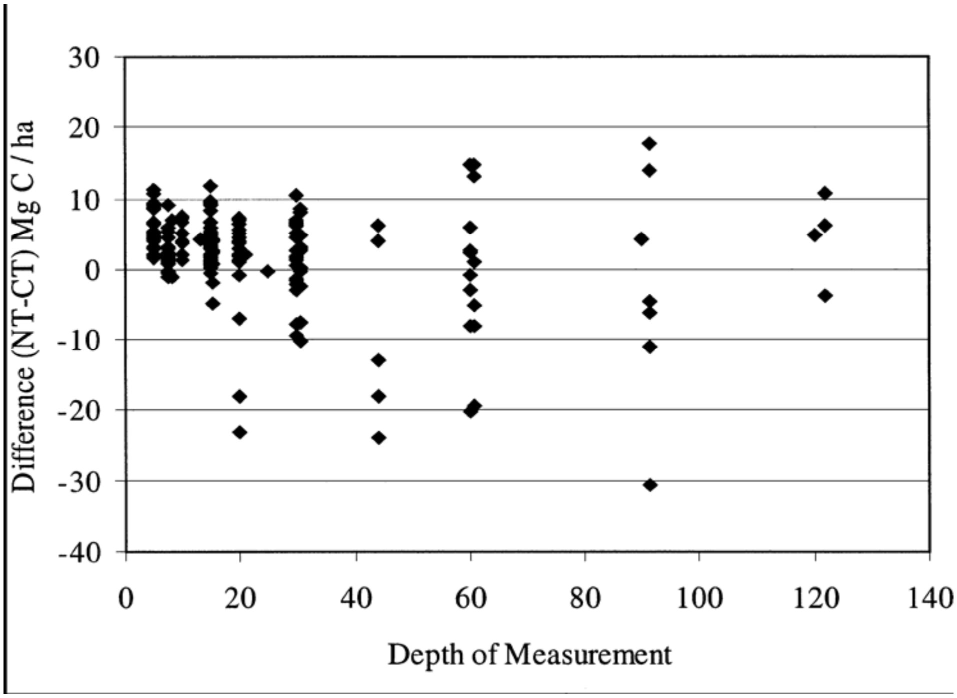
[20] J.G. Manley et al., "Creating Carbon Offsets in Agriculture Through No-Till Cultivation: A Meta-Analysis of Costs and Carbon Benefits," *Climatic Change* January 2005; 68(1–2):41–65. See http://www.springerlink.com/content/t123403l3u560275/

[21] See National Soil Tilth Laboratory Web site: http://www.ars.usda.gov/main/site_main.htm?modecode=36-25-15-00

Figure I-1. Differences in soil carbon levels achieved through no-till based on measurement depth



NT = no-till; CT = conservation till; Mg = million grams; C = carbon; ha = hectare.

This uncertainty is further highlighted by Lennon and Nater, who have reviewed literature focusing on management practices that promote sequestration in Minnesota.[22] Their paper states that “although, no-tillage systems do provide a number of important ecological services, such as erosion control and water quality benefits, a critical review of the literature to date leads us to conclude that no-tillage systems do not sequester more carbon than conventional tillage systems.” It appears that carbon sequestration rates appear sensitive to depth of measurement. Additional research on how to increase soil carbon sequestration in agricultural management is required

An additional uncertainty surrounds the current uptake of conservation tillage within Minnesota. While states elsewhere in the United States have been adopting no-till practices, the trend in Minnesota has been away from such practices because of Minnesota’s climate. Minnesota’s soil temperature, soil moisture, and length of growing season raise questions about the potential of increasing the uptake of conservation tillage practices, as required by this policy recommendation.

Regarding nitrogen fertilizer use efficiency, there may be competing forces between the nitrogen efficiency goal and the tillage goal. For example, if there is a major shift to no-till practices,

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[19] M.J. Lennon and E.A. Nater, “Biophysical Aspects of Terrestrial Carbon Sequestration in Minnesota,” St. Paul, MN: University of Minnesota, Water Resources Center, 2006. See http://wrc.umn.edu/outreach/carbon/whitepapers/biophysical.pdf

farmers may need to increase nitrogen rates because of reduced mineralization rates (less aeration and physical disturbance), cooler surface temperatures, and increased losses from volatilized unincorporated urea. Reduced-tillage systems will also make capturing nitrogen from manure more difficult.

When measured by crop output per unit of fertilizer applied (e.g., bushels per lb N), the fertilizer efficiency goal under this policy may be difficult to achieve. There have been significant increases in nitrogen fertilizer use efficiency over the past 17 years. However, some of these improvements may be due to added heat units during the summer months, resulting in higher mineralization rates, better weed control, and improved genetics. Based on current trends, analysis by the MDA indicates that nitrogen use efficiency could increase by 40% by 2025,[23] assuming such management factors as tillage remain relatively constant.

Uncertainty also surrounds the difference in yield as a consequence of implementing these policies. The effect of adopting alternative crop management practices on yields has not been included in this analysis. The University of Minnesota has conducted analysis in relation to the impact of various tillage practices on yield.[24] This analysis indicated varying results as a consequence of applying different tillage practices. If yield is reduced, output per unit of input may decrease.

Given the level, type, and importance of key assumptions and feasibility issues, the quantified impact is highly uncertain. Thus, these policy proposals need much more thorough analysis prior to their implementation.

Additional Benefits and Costs

Soil carbon management (e.g., no-till) systems provide a number of important ecological services, including erosion control and water quality benefits.

Feasibility Issues

1. If changes in management result in decreased crop yields, the net carbon flux can be greater under the new system, assuming that crop demand remains the same and additional lands are brought into production. Conversely, if increased crop yields lead to less land under cultivation, the overall carbon savings from changes in management will be greater than when soil carbon sequestration alone is considered.

2. Options to increase carbon can be implemented in the short term, but the amount of carbon sequestered typically is low initially, then rises for a number of years before tapering off again as the total potential is achieved. There is also a significant risk that the carbon sequestered may be released again by natural phenomena or human activities.

3. Practices for conserving carbon affect emissions of other GHGs. Of particular importance is the interaction of carbon sequestration with N_2O emissions, because N_2O is such a potent

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[23] Analysis by Bruce Montgomery (Pesticide and Fertilizer Management Division) provided by Paul Burns (Assistant Director, Agricultural Development and Financial Assistance Division).

[24] See http://www.extension.umn.edu/distribution/cropsystems/components/DC8315g.html

GHG. In some environs, carbon-sequestration practices, such as reduced tillage, can stimulate N_2O emissions, thereby offsetting part of the benefit. Elsewhere, carbon-conserving practices may suppress N_2O emissions, amplifying the net benefit. Similarly, carbon-sequestration practices may affect emissions of methane (CH_4) if the practice, such as increased use of forages in rotations, leads to higher livestock numbers. Policies designed to suppress emission of one GHG need to also consider complex interactions to ensure that net emissions of total GHGs are reduced.

4. International and domestic interactions of the marketplace have not been considered in the foregoing cost-benefit analysis. Current escalating energy costs may lead to sharp changes in crop production practices, while international commodity prices may lead to more intensive crop inputs.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

AFW-2. Land-Use Management Approaches for Protection and Enrichment of Soil Carbon

Policy Description

This policy converts marginal or sensitive agricultural land with an immediate history of use for annual crop production to permanent cover, such as grassland/rangeland, orchard, or forest on land that was formerly forested, where the soil carbon and/or carbon in biomass is substantially higher under the new land use. This includes opportunities to keep CRP, Conservation Reserve Enhancement Program (CREP), and Reinvest in Minnesota (RIM) lands in well-managed, continual cover, while also providing opportunities for working lands to increase carbon sequestration through biomass production that can provide feedstocks for in-state bioenergy production.

Incentives need to be created to convert annual row-crop acres to perennial crops that prevent these acres from either returning to conventionally tilled production or to suburban/urban development. Incentives also need to be created for promoting carbon sequestration goals on public lands and lands enrolled in existing conservation programs. Finally, research should be conducted and programs adopted to identify and eliminate threats to the vast carbon pools currently stored in lands that hold high levels of soil organic carbon, such as peatlands and wetlands.

Wetlands have among the highest potential carbon-sequestration capacities for any type of land cover in Minnesota. Peatlands are likely Minnesota's largest single carbon sink, containing 37% of all carbon stored in the state, compared with 3% stored in the state's forests. Protecting these enormous carbon reservoirs from the impacts of warmer and drier conditions and increased fire risk is critical. Early attention should be given to identifying degraded peatlands at risk of re-emitting sequestered CO_2 and CH_4. Additional study is needed to understand GHG dynamics in the full range of wetland types in Minnesota and to apply this understanding to the state's wetland conservation policies to reduce the risk of releases of stored GHGs from these systems.

Policy Design

Goals:

Natural Coverage Protection—Protect 10% by 2015 and 30% by 2025 of lands in natural cover and/or existing conservation programs that would have been converted to intensive agricultural production or urban/suburban development.

Perennial Production on Working Lands—By 2025, expand the Reinvest in Minnesota–Clean Energy () program land to 200,000 acres.

Protection of Peatlands & Wetlands—Protect or restore northern peatlands and other wetlands to prevent releases of GHGs and fire and to allow existing peatlands to continue to sequester carbon. The MCCAG is not comfortable presenting numeric goals at this time. Please see alternative goals under "Protection of Peatlands & Wetlands," below in the "Other" subsection.

Timing:

Natural Coverage Protection—Protect 10% by 2015 and 30% by 2025 of lands in natural cover and/or existing conservation programs that would have been converted to intensive agricultural production by 2015. Achieve the full goal by 2025. The goal could be met in whole or in part by increasing the amount of privately held high-carbon-value lands in land protection programs by 10% by 2015, and by 25% by 2025, and making carbon sequestration an additional management priority for 25% of publicly held and managed lands in Minnesota by 2025.

Perennial Production on Working Lands—By 2015, establish and/or produce low-carbon perennial energy crops on 20,000 acres of land in Minnesota. Achieve the full 200,000-acre goal by 2025.

Protection of Peatlands & Wetlands—By 2015, identify peatlands at risk of releasing GHGs because of lowered water tables, fire potential, or industrial uses (horticulture, sod farming, or mining). By 2015, initiate a research program on fire potential and management in peatlands. By 2015, develop carbon management standards for wetlands and peatlands. By 2025, raise water table elevations as high as practicable on degraded peatlands and/or plant with appropriate forest species.

Parties Involved: Minnesota Board of Soil and Water Resources, Minnesota Department of Natural Resources (DNR), university researchers (including those from the University of Minnesota), Rural Advantage, the Agricultural Utilization Research Institute (AURI), Minnesota Waterfowl Association, Delta Waterfowl, Ducks Unlimited, Izaak Walton League of America, Institute for Agriculture and Trade Policy, Land Stewardship Project, Minnesota Project, National Farmers Union, Minnesota Farm Bureau, Minnesota Corn Growers Association, Minnesota Soybean Association, Minnesota Wheat Growers, The Nature Conservancy, Trust for Public Land, Pheasants Forever, county land departments, USDA Forest Service, U.S. Fish and Wildlife Service, industrial landowners, tribal governments, University of Minnesota Research and Extension.

Other:

Agricultural Land Protection—This policy would create a program to provide additional tax incentives for landowners donating development rights as part of an easement transaction for the carbon storage value of their land. These programs need to be assessed for their carbon sequestration benefit. Management strategies need to ensure that the original goals and public values (water quality, soil conservation, and wildlife habitat) are not diminished as carbon sequestration goals are met.

This policy can assist with the promotion of the goals of AFW-3 and AFW-4, by providing some incidental biomass for bioenergy and biofuel production, but these lands should not be viewed as primary biomass sources. Federal- and state-managed and -contracted lands (including federal wildlife refuges, DNR wildlife management areas, state forest lands, national and state park areas, Bureau of Land Management lands, national forests and grasslands, and CRP, CREP, and RIM acres) are managed for a variety of purposes under many state and federal laws. In many instances, these purposes could include carbon sequestration. Most public lands and all CRP, CREP, and RIM land are managed at least in part to preserve the public's interest in their noncommodity values—mainly water quality improvement, soil conservation, and wildlife habitat.

At present, the carbon storage value of lands protected is an uncompensated additional benefit that comes with the open space and wildlife habitat protection values of protecting lands. Moreover, there are clear examples of public lands being managed in ways that are counterproductive or that squander the land's natural carbon sequestration and detention potentials. Additional incentives that monetize stored carbon and changes in carbon storage on the land—over and above existing compensation for retiring development and production rights—would increase the acreage of high-carbon-value lands that are managed for carbon sequestration, and compensate landowners for the additional societal benefit of avoided carbon emissions.

Perennial Production on Working Lands—While protection of existing perennial production on conservation and public lands is necessary, the vast majority of agricultural land is currently used intensively to produce annual crops that have uncertain ability to sequester carbon over the long term. Programs to encourage production of perennial crops on acres currently in agricultural production should be funded and expanded quickly.

The RIM-CE program should be fully funded in 2008. This program is a working-lands program for bioenergy production that was established in the 2007 Minnesota legislative session. It provides long-term easements and training to farmers who want to begin growing next-generation energy crops (such as diverse native prairie grass species or monocultures of native species, such as switchgrass) for sale to facilities needing the crops for heat, power, and transportation fuel production. Tiered payments are made based on increased levels of public benefits—specifically, carbon sequestration in the deep-root systems of diverse native perennial grassland plantings, and improved water quality and wildlife habitat. After a short lead time for establishment of the crops, the state will begin reaping the benefits as each acre sequesters carbon below ground, while producing harvestable biomass fuels above ground. This will jump-start the production of energy crops in the state, providing some of the feedstocks to meet the goals outlined in AFW-3 and AFW-4.

Protection of Peatlands & Wetlands—Research and increased management of the vast carbon pools stored in wetlands and peatlands are critical. A high percentage of all carbon stored in Minnesota is in wetlands and peatlands. Efforts to protect these carbon reservoirs from the impacts of warmer and drier conditions and increased fire risk should include identification of wetlands and peatlands at risk of re-emitting sequestered CO_2 and CH_4. Policies need to be designed to protect peatlands and wetlands from drainage and other carbon-releasing land uses. Additional research should be conducted to evaluate their contribution to carbon sequestration and long-term storage. In particular, policies should:

- Identify areas where significant peatland carbon stocks are in danger of being oxidized by drainage infrastructure, and evaluate and conduct hydrologic or vegetation management, including afforestation with appropriate forest species.
- Evaluate the GHG impacts of horticulture, sod farming, and energy production on peatlands, and develop standards to protect carbon stocks.

- Protect carbon stocks in freshwater mineral wetlands, and support development of scientific understanding and management options for GHGs associated with mineral wetlands.
- Initiate a serious research program investigating the fire potential and management of peatlands.

Implementation Mechanisms

Protection of Peatlands & Wetlands

- Identify peatlands that are in danger of ceasing their present carbon sequestration or releasing their stored carbon.
- Expand existing databases to provide baselines for future evaluations of carbon sequestration or carbon release by Minnesota peatlands.
- Fund restoration of water tables and flows necessary to restore degraded peatlands and preserve existing peatlands.
- Support research aimed at the past, present, and future of carbon sequestration in Minnesota peatlands.
- Maintain or expand funding for existing or past peatland management and protection programs within state agencies.
- Educate landowners about the role of peatlands in reducing carbon in the air.
- Encourage peatland owners to adopt voluntary BMPs for maintaining peatlands, such as protecting peatlands from nutrients from nearby fertilized fields.

Related Policies/Programs in Place

Minnesota has invested significantly in preservation and restoration of important conservation lands, including forests, prairies, and wetlands. The Minnesota DNR owns and manages more than 1.1 million acres of public conservation lands in addition to the state's forestland. Minnesota also holds long-term conservation easements on nearly 200,000 acres of privately owned lands. Restoration and management strategies for these lands focus on restoring diverse native plant communities, which are shown to be very productive in sequestering carbon. Existing and prospective large-scale forest conservation easements in Koochiching and Itasca counties (53,000 acres existing, 76,000 acres prospective, respectively) are likely to protect tens of thousands of acres of privately owned peatland.

In 1991, Minnesota established the Wetland Conservation Act, one of the most sweeping wetland protection laws in the nation. With a goal of no net loss of wetlands, this act requires anyone proposing to drain, fill, or excavate a wetland first to try to avoid disturbing the wetland, second to try to minimize any impact on the wetland, and finally to replace any lost wetland acres, functions, and values.

Federal government programs prohibiting drainage of agricultural wetlands are administered by USDA's NRCS and FSA. Minnesota programs must dovetail with federal programs to avoid confusion and streamline impacts.

Type(s) of GHG Reductions

CO_2: Conservation of agricultural lands retains the ability of the land to sequester carbon in soil and biomass. Also, emissions are indirectly reduced to the extent that development patterns are influenced and vehicle miles traveled (VMT) are reduced (see the Transportation and Land Use (TLU) MCCAG recommendations).

Estimated GHG Reductions and Net Costs or Cost Savings

GHG Reduction Potential in 2015, 2025 (MMtCO_2e): 0.23, 0.62, respectively (total includes the reductions for the A. Preserved Land and B. RIM-CE elements).

Net Cost per tCO_2e Reduced: $33 (total includes costs for elements A and B).

Data Sources:

NRCS data on CRP acres expiring during the policy period, NRCS National Resources Inventory (NRI) data on agricultural/range/forest land lost to urban development, and data on above- and below-ground soil carbon levels from a USDA study.

Quantification Methods:

Natural Coverage Protection GHG Benefits

The amount of land in natural cover and/or existing conservation programs that is potentially available for conversion was obtained from NRI data[25] and USDA FSA data on active and expiring CRP cropland acres.[26] Over the NRI data period, the average loss of land to developed use was estimated at 3,400 acres/year. These conversion estimates are multiplied by the targets (10% by 2015 and 30% by 2025), to yield the averted conversion in the target years. Land enrolled in the CRP has remained relatively constant over the last decade. However, there are expectations that the reenrollment rate will begin to decrease as the price of agriculture crops (e.g., corn) increases, making other (non-CRP) land uses more attractive. While the amount of land coming off the CRP program is easily identifiable, the extent to which these contracts will be reenrolled or extended is unknown. A flat reenrollment rate of 84% was assumed, based on historical reenrollment and extension offers. The lands not reenrolled into the CRP are assumed to enter intensive agriculture. The carbon value of grasslands that is lost due to conversion is 0.023 MMtC/1,000 acres.[27] The carbon benefit of preserving lands in natural coverage (e.g.,

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[25] The most recent NRI data available are for 1982–1997. USDA, NRCS, Farm and Ranch Lands Protection Program. NRCS 2003 fact sheets. See www.nrcs.usda.gov/programs/frpp

[26] USDA, FSA, *Conservation Reserve Program Monthly CRP Acreage Report Summary of Active and Expiring CRP Acres by State*, Report ID: MEPEGG-R1, Kansas City, MO, December 28, 2007. See http://content.fsa.usda.gov/crpstorpt/rmepegg/MEPEGGR1.HTM

[27] USDA study, showing a change of about –3 tons/acre over 10 years for land under crop production and +3 tons/acre over 10 years for CRP. Assuming that these are additive (loss of continued sequestration potential in CRP acres, plus losses occurring from cultivated lands, yields + 3 tons C/acre over 10 years. The annual average loss from conservation to cultivation would be 0.6 tons/acre/year (2.2 tCO_2/acre/year). Food and Agricultural Policy Research Institute, *Estimating Water Quality, Air Quality, and Soil Carbon Benefits of the Conservation Reserve Program*, FAPRI-UMC Report #01-07, Columbia, MO: University of Missouri-Columbia, January 2007. See http://www.fapri.missouri.edu/outreach/publications/2007/FAPRI_UMC_Report_01_07.pdf

CRP) compared with cropland is assumed to be 0.935 $MtCO_2e$/acre. This is the midpoint of the range provided by Lennon and Nater (2006).[28] The cost of easements is assumed to be $2,500/acre.[29] The benefits and costs for agricultural land conversion are presented in Table I-6.

Studies are lacking on the changes in below- and aboveground carbon stocks when agricultural land is converted to developed uses. For some land-use changes, carbon stocks could be higher in the developed use relative to the agricultural use (e.g., parks). In other instances, carbon stocks are likely to be lower (graded and paved surfaces). The Center for Climate Strategies (CCS) assumed that the agricultural land would be developed into typical tract-style suburban development with no soil sequestration benefits, and assumed no change in the levels of aboveground carbon stocks.

Natural Coverage Protection Costs

To estimate program costs in each year, CCS multiplied the estimated agricultural acres protected from development by the conservation cost ($2,500/acre). The resulting cost-effectiveness is $33/$tCO_2e$ reduced. This estimate only accounts for the direct reductions associated with soil carbon losses estimated above, and does not include potentially much larger indirect benefits associated with reductions in vehicle miles.

These costs assume steady-state crop commodity prices. As global demand grows and as crops are used to replace fossil fuels, higher commodity prices would be associated with higher costs of reducing cultivated acres.

Table I-6. Benefits and costs of agricultural land conversion

Year	Acres Saved From Developed Use	Acres Saved From Agriculture	$MMtCO_2e$ Saved (From Developed)	$MMtCO_2e$ Saved (From Agriculture)	Costs	Discounted Costs
2008	424	552	0.018	0.001	$1,093,006	$1,040,958
2009	794	1,036	0.033	0.001	$2,049,385	$1,858,853
2010	1,165	1,588	0.049	0.001	$3,010,021	$2,600,170
2011	1,535	2,141	0.064	0.002	$3,970,657	$3,266,669
2012	1,906	2,693	0.080	0.003	$4,931,293	$3,863,797
2013	2,277	3,246	0.095	0.003	$5,891,929	$4,396,648
2014	2,647	3,798	0.111	0.004	$6,852,564	$4,869,990
2015	3,389	4,420	0.142	0.004	$8,744,045	$5,918,314
2016	4,066	5,304	0.170	0.005	$10,492,854	$6,763,787
2017	4,744	6,187	0.199	0.006	$12,241,662	$7,515,319
2018	5,422	7,071	0.227	0.007	$13,990,471	$8,179,939
2019	6,100	7,955	0.255	0.007	$15,739,280	$8,764,220

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[28] Lennon and Nater cite estimates of sequestration rates for the conversion of agricultural land to perennial grasses, ranging from 25 to 101 g $cm^{-2}/year^{-1}$ (or 0.371 to 1.5 tCO_2/acre/year). M.J. Lennon and E.A. Nater, "Biophysical Aspects of Terrestrial Carbon Sequestration in Minnesota," St. Paul, MN: University of Minnesota, Water Resources Center, 2006. See wrc.umn.edu/outreach/carbon/whitepapers/biophysical.pdf

[29] The range of Farmland Protection Program costs for easements is $1,943/acre in Wisconsin and $3,630/acre in Michigan. Based on NRCS 2003 fact sheets. U.S. Department of Agriculture, Natural Resources Conservation Service, Farm and Ranch Lands Protection Program. NRCS 2003 fact sheets. See www.nrcs.usda.gov/programs/frpp

Year	Acres Saved From Developed Use	Acres Saved From Agriculture	$MMtCO_2e$ Saved (From Developed)	$MMtCO_2e$ Saved (From Agriculture)	Costs	Discounted Costs
2020	6,777	8,839	0.284	0.008	$17,488,089	$9,274,307
2021	7,455	9,723	0.312	0.009	$19,236,898	$9,715,941
2022	8,133	10,607	0.340	0.010	$20,985,707	$10,094,484
2023	8,811	11,491	0.369	0.011	$22,734,516	$10,414,944
2024	9,488	12,375	0.397	0.012	$24,483,325	$10,681,994
2025	10,166	13,259	0.426	0.012	$26,232,134	$10,899,993
Cumulative			**3.571**	**0.105**		**$120,120,325**

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

RIM-CE Expansion GHG Benefits

The GHG sequestration benefits of expanding the RIM-CE program were quantified by assuming a constant rate of carbon accumulation of 1 tCO_2e/acre/year.[30] The sequestration rate was applied to acres in the program as indicated in Table I-7. The benefits from reduced diesel use and reduced fertilizer use were calculated using a similar methodology to that used in AFW-1. It was assumed that nitrogen was applied for the first 3 years of RIM-CE land establishment, after which it was assumed that additional nitrogen application is not required. It was assumed that nitrogen was applied at a rate of 77 lb/acre,[31] and the average CO_2 emissions factor was 5.83×10^{-6} $MMtCO_2e$ per ton of nitrogen applied based on historical data. Additional GHG savings from reduced fossil fuel consumption were estimated by multiplying the fossil diesel emission factor (12.31 tCO_2e/1,000 gallons[32]) by the diesel fuel reduction per acre (3.5 gallons/acre[33]).

This policy also overlaps and interacts with AFW-4. The RIM-CE recommendation focuses on the GHG benefit associated with the carbon storage benefits of energy crops, whereas AFW-4 focuses on the displacement of fossil fuel.

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[30] Taken from CCX agricultural grass soil carbon sequestration offset project guidelines. Minnesota is in zone A. See http://www.chicagoclimatex.com/docs/offsets/Grassland_Conversion_Protocol.pdf

[31] Based on historical fertilizer use (lb/acre) in Minnesota from the USDA Web site. See www.ers.usda.gov/Data/FertilizerUse/Tables/Fert%20Use%20Table%207.xls

[32] J. Hill et al., "Environmental, Economic, and Energetic Costs and Benefits of Biodiesel and Ethanol Biofuels," *Proceedings of the National Academy of Sciences* 103(30):11206–11210. From the assessment used to evaluate U.S. soybean-based biodiesel life cycle impacts. See http://www.pnas.org/cgi/content/short/103/30/11206.

[33] Reduction associated with conservation tillage compared with conventional tillage. Conservation Technology Information Center, *What's Conservation Tillage?* See http://www2.ctic.purdue.edu/Core4/support/OrderInfo/ct.pdf, accessed February 2008.

Table I-7. Benefits and costs of expanding the RIM-CE program

Year	Acres in Program	$MMtCO_2e$ Saved (Including Sequestration, Reduced Diesel, and Reduced Fertilizer)	Net Costs (Program Costs Less Savings From Reduced Fertilizer Use)	Savings (Revenue Generated Through Carbon Credits and Sale of Energy Crops)	Net Cost (Program Costs Less Savings)	Discounted Net Cost
2008	10,000	0.010	$23,000,000	–$2,149,000	$22,245,400	$19,858,095
2009	20,000	0.020	$23,000,000	–$4,298,000	$21,490,800	$16,963,265
2010	30,000	0.030	$23,000,000	–$6,447,000	$20,736,200	$14,299,103
2011	40,000	0.047	$22,557,137	–$8,596,000	$19,538,737	$11,485,862
2012	50,000	0.057	$22,557,137	–$10,745,000	$18,784,137	$9,255,118
2013	60,000	0.067	$22,557,137	–$12,894,000	$18,029,537	$7,210,781
2014	70,000	0.077	$22,557,137	–$15,043,000	$17,274,937	$5,340,157
2015	80,000	0.087	$22,557,137	–$17,192,000	$16,520,337	$3,631,336
2016	90,000	0.097	$22,557,137	–$19,341,000	$15,765,737	$2,073,150.
2017	100,000	0.11	$22,557,137	–$21,490,000	$15,011,137	$655,129
2018	110,000	0.12	$22,557,137	–$23,639,000	$14,256,537	–$632,542
2019	120,000	0.13	$22,557,137	$25,788,000	$13,501,937	–$1,799,065
2020	130,000	0.14	$22,557,137	–$27,937,000	$12,747,337	–$2,853,056
2021	140,000	0.15	$22,557,137	–$30,086,000	$11,992,737	–$3,802,587
2022	150,000	0.16	$22,557,137	–$32,235,000	$11,238,137	–$4,655,217
2023	160,000	0.17	$22,557,137	–$34,384,000	$10,483,537	–$5,418,022
2024	170,000	0.18	$22,557,137	–$36,533,000	$9,728,937	–$6,097,622
2025	180,000	0.19	$22,557,137	–$38,682,000	$8,974,337	–$6,700,213
Cumulative		**1.75**				**$58,813,675**

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

RIM-CE Expansion Costs

The cost of the program was assumed to be constant over the period at $2,300 per acre[34]—a once-off payment required for the conversion of land to the RIM-CE program. It was assumed that carbon credits ($2.10/$tCO_2$) would be generated through the Chicago Climate Exchange or a similar future program.[35] It was also assumed that additional revenue would be generated through the sale of the energy crops on the RIM-CE land at a price to the landowner of $38/dry ton,[36] given that switchgrass would be used as the biomass crop on RIM-CE land, with a yield of 5.6 tons/acre.[37] Costs for each year are indicated in Table I-7. Cost savings were also assumed to occur through reduced nutrient application, using a similar methodology to that applied under

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[34] Based on the funding request of $46 million for 20,000 acres.

[35] Assumes that carbon credits can be obtained through future programs. Price sourced from CCX Web site on November 13, 2007. See http://www.chicagoclimatex.com

[36] Grower payment based on the willingness of Koda Energy LLC to buy biomass from local farmers. Koda Energy letter dated February 1, 2007.

[37] "Assume highest yield." J.D. Berdahl et al., "Biomass Yield of Diverse Switchgrass Cultivars and Experimental Strains in Western North Dakota." *Agronomy Journal* April 15, 2005. See www.ars.usda.gov/research/publications/publications.htm?SEQ_NO_115=164799

AFW-1 (assuming an application rate of 77 lb/acre,[38] and multiplying the total fertilizer reduction in each year by the average cost of fertilizer in April 2007[39]).

Protection of Peatlands Costs

One option to protect peatlands is large-scale conservation easements. A recent large forestland easement purchase in northern Minnesota that included a substantial acreage of peatland cost $235/acre (see AFW-6, Economic Analysis). Although the MCCAG is not comfortable presenting numeric peatland protection goals at this time, large-scale conservation easements may be a viable option for continued storage of the vast amounts of carbon and methane in peatland soils.

Key Assumptions:

No change in aboveground carbon stocks, and no appreciable carbon sequestration occurs post-development.

While the amount of land coming off the CRP is easily identifiable, the extent to which these contracts will be reenrolled or extended is unknown. A flat reenrollment rate of 84% was assumed, based on historical reenrollment and extension offers. However, there are expectations that the reenrollment rate will begin to decrease as the price of agricultural crops (e.g., corn) increases, making other (non-CRP) land uses more attractive.

Additional GHG benefits may be provided by the RIM-CE program (as a consequence of perennial cover) through a reduced rate of erosion and the associated avoided emissions due to decreased soil disturbance. The level of avoided emissions is uncertain and is not included in this analysis.

Key Uncertainties

The soil sequestration rates associated with land management practices remain extremely uncertain. Studies, including those by Manley et al., highlight this uncertainty.[40]

The RIM-CE program is in a very early stage of development. It was authorized by the legislature in 2007, and design details along with funding are being developed. Currently, $46 million in funding is being considered by the Governor’s office. It is anticipated that funding decisions and design details will be finalized by early next year.

Future weather patterns and their impacts on Minnesota’s peatlands are uncertain. In general, climate models project warmer and drier conditions for mid-continental interiors, which would increase the risk of CO_2 release from peatlands. There is also uncertainty about adverse impacts of drainage, horticulture, sod farming, and energy production on the extent of carbon sequestration by peatlands.

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[38] Based on historical fertilizer use from the USDA Web site, at www.ers.usda.gov/Data/FertilizerUse

[39] “2007 Fertilizer Use and Cost,” at: www.ers.usda.gov/Data/FertilizerUse/Tables/Fert%20Use%20Table%207.xls

[40] J. Manley et al., “Creating Carbon Offsets in Agriculture Through No-Till Cultivation: A Meta-Analysis of Costs and Carbon Benefits,” *Climatic Change* 68(1–2):41–65, January 2005. See http://www.springerlink.com/content/t123403l3u560275/

The energy crop benefits associated with the program (i.e., offsetting fossil fuel with biomass for energy) have not been included in this analysis. There is significant overlap between this component and AFW-4, particularly in relation to the energy crop production goal.

Additional Benefits and Costs

Additional GHG benefits arise through the displacement of emissions from fossil fuel combustion for energy generation. The energy crop benefits associated with the RIM-CE program (i.e., offsetting fossil fuel with biomass for energy) have not been included in this analysis.

Feasibility Issues

The cost of incentives that may be required for private property would be expected to come from the public. The level of incentive required is uncertain, and the ability to locate resources to pay for the incentive needs to be determined.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

AFW-3. In-State Liquid Biofuels Production

Policy Description

This policy promotes sustainable in-state production and consumption of transportation biofuels from agriculture and/or agroforestry feedstocks to displace the use of gasoline and diesel. It decreases the use of fossil fuel in the production of these biofuels, which will improve the GHG profile of in-state liquid biofuels production and consumption. Sustainability standards also needed to be developed for low-carbon biofuels, so that producers are rewarded accordingly.

This policy also promotes the in-state development of feedstocks, such as cellulosic material and perennials that are able to be utilized. Recognizing that conversion technologies, such as thermo-chemical Fischer-Tropsch processes and enzymatic conversion, are developing fast in this sector, the policy recommends facilitating, but not requiring, their development.

AFW-3 also promotes multiple biofuel (ethanol, biodiesel, biobutanol) production systems that improve the embedded energy content, life cycle, and carbon profile of biofuels. It focuses on plant material feedstocks that favor energy production, that are carbon neutral or negative, and that have multiple other positive environmental benefits, such as maintaining carbon-sequestration potential and soil productivity, and decreasing water and fossil fuel inputs in their production.

To achieve true gains in reducing GHGs, promoting biofuel production must be coupled with strong policies to reduce overall transportation fuel consumption. Upon successful implementation of this policy, Minnesota consumption of biofuels produced in-state will produce better GHG benefits than these same fuels obtained from a national market due to lower embedded CO_2 (resulting from out-of-state fuels produced using feedstocks/production methods with lower GHG benefits, and from transportation of biodiesel, ethanol, other fuels, or their feedstocks from distant sources).

Note: This recommendation is linked with the Transportation and Land Use recommendation TLU-3, a Low-Carbon Fuels Standard. It seeks to achieve incremental GHG benefits beyond the TLU recommendation by promoting in-state production of biofuels using feedstocks with greater GHG benefits than the likely BAU national production methods. Further, AFW-3 focuses on the supply elements of the implementation of a biofuels program while TLU-3 focuses on the demand side (e.g., vehicle technology requirements, E10, E85).

Policy Design

Goals:

Lower Carbon Footprint of Ethanol Produced From Existing Plants—By 2015, produce 80% of the thermal heat used in ethanol facilities from biomass or other renewable energy; by 2017, produce 80% the electrical power consumed by ethanol facilities from biomass or other renewable energy. The goal of this policy design is to decrease the use of fossil fuel in the existing production of Minnesota biofuels by using low-GHG life-cycle biomass for the heat and power inputs into biofuel production facilities. A technology that could achieve this goal is biomass gasification, which is currently available.

Gasoline Displacement—By 2025, achieve in-state production (based on energy content) equivalent to offsetting 50% of the gasoline consumed in the state (i.e., replace gasoline with biofuels using feedstocks and conversion processes that are superior to today's conventional sources).

At the Minnesota Climate Change Advisory Group's (MCCAG's) request, additional analyses of alternative goals at 35% and 20% displacement were conducted (see gasoline displacement quantification section for details). The 35% displacement goal was selected by the MCCAG as the recommendation for gasoline displacement.

Fossil Diesel Displacement—Increase in-state biodiesel production to offset 10% of fossil diesel consumption by 2025 (i.e., the fossil diesel consumed in the state will by replaced by biodiesel produced using feedstocks and conversion processes that are superior to today's conventional sources).

Timing:

Lower the Carbon Footprint of Ethanol Produced From Existing Plants—See above.

Gasoline Displacement—Incremental increases, up to achieving the full 50% goal by 2025.

Fossil Diesel Displacement—Incremental increases, up to achieving the full 10% goal by 2025.

Parties Involved: Biofuel production facilities, Minnesota Department of Commerce (MnDOC), MDA, Next Generation Energy Board, sustainable agriculture groups, conservation and renewable energy nonprofits, those currently developing standards (e.g., Forest Resource Council, Board of Water and Soil Resources), engineering firms, forest products industry, agriculture production group researchers at the University of Minnesota, AURI.

Other: Current state policy for fossil diesel displacement is 2% biodiesel blend. For gasoline displacement, current policy is 20% ethanol displacement by 2013, with a carve-out goal for 5% derived from cellulosic material. The current petroleum displacement goal is that 20% of the liquid fuel sold in the state will come from renewable sources by 2015, and 25% by 2025. This new policy would need to be coupled with strong reductions in fossil gasoline/diesel consumption demand out to 2025 and high-biofuel-content (e.g., E85) vehicle/infrastructure.

Money related to capital conversion for certain near-term technologies, such as gasifiers, may need to be allotted. A certification process to acknowledge that Minnesota-produced biofuels have lower carbon footprints (e.g., for future Minnesota, California, and potentially national low-carbon fuel standard (LCFS) markets) is needed. Incentives for planting crops that have a low-carbon profile that can be used as boiler fuel should be enacted (e.g., RIM-CE program).

Note the linkage of AFW-3 to TLU-3 for establishing an LCFS that will stimulate the biofuels production envisioned by this policy, as well as innovation and investment in biofuel production technologies; promote efficiency and low-carbon feedstocks/fuel inputs in biofuel production facilities; and increase demand for biofuels blending in transportation fuel production processes.

AFW and TLU policies that address labeling and certification to verify low- and zero-carbon biofuel players should be implemented, to allow for a sound low-carbon fuels market to be developed locally and nationally. Any Minnesota-based fuel standard/certification process should be able to easily integrate into the emerging California, federal (U.S. Environmental Protection Agency), and European LCFS, as well as any tax or cap regimes established for Minnesota and the Upper Midwest. AFW-3 focuses on the supply elements of the implementation of a biofuels program, while TLU-3 focuses on the demand side (e.g., vehicle technology requirements, E10, E85)

Note the linkage of AFW-3 to AFW-2 on funding the RIM-CE program (200,000 acres growing low-carbon energy crops by 2025). This program is a working-lands program for bioenergy production that was established in the 2007 legislature. It provides long-term easements and training to farmers who want to begin growing next-generation energy crops, such as switchgrass and other diverse prairie grasses, for sale to facilities needing the crops for heat and power (gasifiers). Tiered payments are made based on increased levels of public benefits, such as carbon storage in the roots, and improvements to water quality/use and wildlife habitat. The state needs to begin planting these energy crops and training farmers on how to grow them, especially since there is a lead time establishing the crops. Getting started now will set the stage for utilizing the energy crops for biofuels in the coming years, as well as linking to the goals outlined in AFW-1 and AFW-2.

Implementation Mechanisms

- Incorporate a low-carbon index for biofuels production, along with feedstock sustainability standards. By 2015, implement a life-cycle certification/labeling process for low-carbon fuels (either through Minnesota-specific or adoption of regional/national standards) that credits biofuels for varying reductions in their carbon intensity, ranging from 25% to 100%.
- Create efficiency incentives for ethanol facilities to upgrade their equipment to consume less heat and power.
- Plant energy crops, so the feedstock is available. Pilot projects may be needed in the near term to assess the economics of this effort with regard to broader-scale commercialization in the long term (e.g., via RIM-CE).
- Allot dollars for development of sustainability standards, to complete the research gaps identified by the Forest Resource Council on its woody biomass residue harvest guidelines and establishment of agricultural sector energy crops (i.e., via Minnesota Board of Water and Soil Resources programs). The result could be a spectrum certification process that certifies low-GHG fuels and other green attributes of the biofuel life-cycle process.
- Establish MMBtu energy incentives for biomass conversion facilities to install biomass feedstock acceptance (conveyers, etc.) and address their storage needs. An MMBtu incentive is preferable, as it focuses on incentivizing the input of high-MMBtu feedstocks and efficient conversion of the biomass into energy (for a high-MMBtu output). This implementation mechanism would be technology neutral and performance based (i.e., it could be used for gasifiers, or whatever technology is developed in this rapidly changing market).
- Develop a template for a contract between facilities and farmers/intermediary/co-op to minimize the risk for all parties (e.g., if farmers can’t meet long-term contractual needs).

Related Policies/Programs in Place

Ethanol: Minnesota established an ethanol production incentive to provide payment to producers to help develop a new market for the state's agricultural products. On the market side, Minnesota requires that all gasoline sold in the state be blended with a 20% ethanol mix by 2013. Of this, the state has a goal of deriving a quarter of the renewable fuel standard (RFS) from cellulosic-derived biofuel by 2015, or when 60 million gallons come online, whichever is first. In addition, Minnesota began efforts in 1997 to develop a network of fueling stations for flex-fuel vehicles that can run on an 85% ethanol blend.

Biodiesel: According to DOE, biodiesel has the most favorable energy balance of any currently commercially viable transportation fuel. For every unit of energy needed to produce a gallon of biodiesel, 3.2 units of energy are gained. As of September 29, 2005, Minnesota requires nearly all diesel fuel sold in the state to contain at least a 2% biodiesel blend.

Petroleum Replacement Goal: A state goal specifies that 20% of the liquid fuel sold in Minnesota will come from renewable sources by 2015, and 25% by 2025. Many grants are available for bioenergy facilities through MnDOC and MDA.

RIM-CE: RIM-CE is a working-lands program that allows for growing and harvesting bioenergy crops with added payments for increased conservation and water quality benefits. The program still needs funds for granting easements for bioenergy crops.

Federal 2007 Energy Act: This act calls for a national standard of transportation fuels from biofuels of 36 billion gallons by 2022, along with an economic analysis of the impacts of this requirement. Of the 36 billion, 20 billion are to be derived from advanced biofuels other than corn. Note that this act does not guarantee any specific level of funding to individual states.

Type(s) of GHG Reductions

CO_2: Life-cycle emissions are reduced to the extent that biofuels are produced with lower embedded fossil-based carbon than conventional (fossil) fuel. Feedstocks used for producing biofuels can be made from crops or other biomass, which contain carbon sequestered during photosynthesis (e.g., biogenic or short-term carbon).

Estimated GHG Reductions and Net Costs or Cost Savings

GHG Reduction Potential in 2015, 2025 ($MMtCO_2e$): A. Ethanol carbon content: 1.8, 2.2, respectively; B. fossil diesel displacement: 0.03, 0.19, respectively; C. 35% gasoline displacement: 2.8, 9.1, respectively.

Net Cost per tCO_2e Reduced: A. –$9 (cost saving); B. $55; C. $5.

The above figures represent a stand-alone analysis. It is assumed that there is 100% overlap with TLU-3 (Low-GHG Fuel Standard) for elements B and C, although this issue should be further assessed.

GHG reduction potentials for 50% and 20% gasoline displacement goals were also estimated and are presented below.

Data Sources: These sources are cited within the quantification methods section below.

Quantification Methods:

GHG Reductions From Lowering the Carbon Footprint of Ethanol Produced From Existing Plants

It is estimated that 80% of energy (both thermal and electricity) consumed by ethanol facilities will come from biomass or other renewable sources: 80% of thermal by 2015, and 80% of electricity by 2017.

Energy use in typical ethanol plant types was taken from Wang et al.,[41] who estimated the energy intensity of existing ethanol production per gallon of ethanol produced using the GREET (Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation) model developed at Argonne National Laboratory. They assumed that the BAU ethanol plant utilized natural gas as a heat input and grid-sourced electricity. The energy required to produce 1 gallon of ethanol is indicated in Table I-8.

Table I-8. BAU ethanol plant energy use per gallon of ethanol

Ethanol Plant Type	Natural Gas (Btu)	Coal (Btu)	Renewable Process Fuel (Btu)	Electricity (kWh)
Existing plant with natural gas	33,330	None	None	0.75

Btu = British thermal unit; kWh = kilowatt hours.

Full production from existing ethanol plants is assumed. Currently, Minnesota's 16 ethanol plants have an annual production capacity of approximately 620 million gallons,[42] which is approximately 13% of the total U.S. output. An additional four plants are under construction, with another 400 million gallons of capacity.[43] Once construction of these facilities is complete, Minnesota's total ethanol production capacity will be over one billion gallons of ethanol per year. From 2010, the ethanol production capacity is assumed to grow at the projected on-road fuel-growth factors used in the Minnesota I&F transportation projections.[44] The emissions from an ethanol facility using conventional sources for heat and electricity were calculated by multiplying the energy input (both natural gas and electricity) by their respective emission

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[41] M. Wang, M. Wu, and H. Huo (2007), "Life-Cycle Energy and Greenhouse Gas Emission Impacts of Different Corn Ethanol Plant Types," *Environmental Research Letters* 2(024001), May 22, 2007. See http://www.iop.org/EJ/abstract/1748-9326/2/2/024001/

[42] Minnesota Pollution Control Agency, Minnesota Department of Natural Resources, Minnesota Department of Agriculture, Minnesota Department of Employment and Economic Development, Minnesota Department of Transportation, Minnesota Department of Commerce, and Minnesota Department of Health, *Planning and Constructing an Ethanol Plant: A Guidance Document,* August 2007 (revised). See http://www.pca.state.mn.us/publications/ethanol-guidancedoc.pdf

[43] From personal communications with Ralph Groschen, Agriculture Marketing Specialist, MDA.

[44] On-road fuel growth factors: 2005–2010, 1.32%; 2010–2015, 1.37%; 2015–2020, 1.27%; 2020–2025, 1.07%; and 2025–2030, 1.27%.

factors. The emission factor for natural gas was assumed to be 0.0539 tCO_2e/MBtu,[45] and the electricity emission factor was assumed to be 0.720 tCO_2e/MWh.[46]

The GHG emissions from ethanol plants incorporating renewable energy were calculated using a similar methodology, but the fossil-based energy inputs were reduced by the policy design requirements. The emissions from the renewable energy inputs were assumed to be zero. The emissions associated with the production of ethanol from BAU and policy plants are indicated in Table I-9.

Table I-9. GHG benefits of sourcing renewable energy for ethanol production

Year	BAU Production Gallons of Ethanol (1,000 gallons)	Renewable Energy Input Goal	Renewable Electricity Goal	BAU Emissions ($MMtCO_2e$)	Emissions Under the New Policy	GHG Emissions Saved ($MMtCO_2e$)
2008	620,000.0	10%	8%	1.449	1.580	–0.132
2009	1,000,000.0	20%	16%	2.336	2.280	0.056
2010	1,013,726.3	30%	24%	2.368	2.039	0.329
2011	1,027,640.9	40%	32%	2.401	1.791	0.610
2012	1,041,746.6	50%	40%	2.434	1.535	0.899
2013	1,056,045.9	60%	48%	2.467	1.272	1.195
2014	1,070,541.4	70%	56%	2.501	1.002	1.499
2015	1,085,236.0	80%	64%	2.535	0.724	1.811
2016	1,099,059.1	80%	72%	2.568	0.676	1.891
2017	1,113,058.2	80%	80%	2.600	0.627	1.973
2018	1,127,235.7	80%	80%	2.634	0.635	1.998
2019	1,141,593.8	80%	80%	2.667	0.643	2.024
2020	1,156,134.7	80%	80%	2.701	0.652	2.050
2021	1,168,563.1	80%	80%	2.730	0.659	2.072
2022	1,181,125.0	80%	80%	2.759	0.666	2.094
2023	1,193,821.9	80%	80%	2.789	0.673	2.116
2024	1,206,655.4	80%	80%	2.819	0.680	2.139
2025	1,219,626.8	80%	80%	2.849	0.687	2.162
					Cumulative	**26.8**

BAU = business as usual; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; GHG = greenhouse gas.

It should be noted that this policy may overlap with AFW-3, particularly in relation to the available supply of biomass, both as a source of energy and as a feedstock in the production process.

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[45] Taken from Minnesota I&F Energy Supply projections.

[46] Minnesota State annual CO_2 output emission rate, from the U.S .Environmental Protection Agency's Emissions & Generation Resource Integrated Database (eGRID). See http://www.epa.gov/cleanenergy/egrid/

Cost of Lowering the Carbon Footprint of Ethanol Produced From Existing Plants
The cost of this policy was estimated using a methodology similar to the quantification of GHG benefits. The energy input required was multiplied by the cost of energy for each of the energy inputs. The cost of each energy input is presented in Table I-10 and is based on the DOE Energy Information Administration's (EIA's) *Annual Energy Outlook 2007* (AEO2007), using the National Energy Modeling System, a computer-based model that produces annual projections of energy markets for 2005–2030. Renewable electricity was assumed to cost 15% above conventional electricity in the period 2008–2015 (5% 2015–2020 and equal from 2020 forward).[47] The renewable energy component is assumed to be sourced from biomass. The cost of biomass was assumed to be $47/ton.[48] This equates to $3.03/MMBtu for biomass, which remains constant over the policy period.[49]

Table I-10. Cost of energy inputs

Year	Natural Gas ($/MBtu)	Coal ($/MBtu)	Electricity–Industry Prices (cents per kWh)	Renewable Electricity (cents per kWh)
2008	6.23	1.63	5.94	6.83
2009	5.66	1.59	5.91	6.80
2010	5.35	1.77	5.68	6.54
2011	4.93	1.93	5.36	6.16
2012	4.77	1.90	5.13	5.90
2013	4.58	1.97	5.03	5.79
2014	4.61	1.83	4.97	5.72
2015	4.55	1.84	4.96	5.71
2016	4.68	1.81	5.01	5.26
2017	4.86	1.80	5.10	5.35
2018	4.83	1.73	5.13	5.39
2019	4.82	1.67	5.15	5.40
2020	4.94	1.75	5.19	5.45
2021	4.91	1.69	5.24	5.24
2022	5.06	1.62	5.32	5.32
2023	5.20	1.58	5.46	5.46
2024	5.30	1.61	5.55	5.55
2025	5.26	1.62	5.51	5.51

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[47] This premium on renewable electricity is based on the assumption that, on average, renewable electricity generation is currently more expensive than conventional sources. For example, the IPCC *Climate Change 2007: Mitigation of Climate Change* report indicates a large range of generation costs of renewable electricity compared with conventional electricity (ranging from a 0% to 500% difference in generation costs, depending on the type of technology employed); 15% is a moderate assumption and declines over the policy period as technological advances lead to cost reductions.

[48] Cost per dry ton for dry Herbaceous Biomass Feedstock Collection, Preprocessing and Delivery to conversion Reactor Inlet. Sourced from DOE, Office of Energy Efficiency and Renewable Energy, Biomass Program, *Biomass Program Biomass Multi-Year Plan*, October 2007. See http://www1.eere.energy.gov/biomass/publications.html

[49] Assumes heat content of biomass is 7,752 Btu/lb, based on an average from BioPET.

$/MBtu = dollars per million Btu's; kWh = kilowatt hours.

The costs associated with the BAU facility and the "policy" facility (assumed to use biomass to replace natural gas). Policy facilities are indicated in Table I-11.

Table I-11. BAU and policy costs

Year	BAU Costs	Incremental Costs Under the Policy (Including Fuel Price, Incremental Capital Costs, Maintenance and Other Costs—Assume Biomass As Renewable Alternative)	Cost/Savings	Discounted Cost/Savings ($MM)
2008	$156,319,572	$153,643,611	–$2,675,961	–$2.55
2009	$232,927,645	$225,685,745	–$7,241,900	–$6.57
2010	$223,829,277	$213,141,229	–$10,688,049	–$9.23
2011	$210,045,275	$199,202,343	–$10,842,931	–$8.92
2012	$205,775,923	$193,082,220	–$12,693,702	–$9.95
2013	$200,991,478	$188,492,696	–$12,498,783	–$9.33
2014	$204,330,414	$187,910,388	–$16,420,026	–$11.67
2015	$205,137,247	$187,021,748	–$18,115,498	–$12.26
2016	$212,690,735	$188,977,877	–$23,712,858	–$15.29
2017	$222,978,285	$195,396,510	–$27,581,775	–$16.93
2018	$224,827,428	$198,347,272	–$26,480,155	–$15.48
2019	$227,406,444	$201,268,159	–$26,138,285	–$14.55
2020	$235,226,209	$205,626,758	–$29,599,451	–$15.70
2021	$237,232,401	$205,987,369	–$31,245,031	–$15.78
2022	$246,465,475	$210,635,164	–$35,830,311	–$17.23
2023	$255,616,951	$213,396,645	–$42,220,306	–$19.34
2024	$263,339,445	$214,974,388	–$48,365,057	–$21.10
2025	$264,336,893	$216,702,540	–$47,634,353	–$19.79
Total				**–$242**

BAU = business as usual; $MM = million dollars.

In addition to the difference in fuel costs, there a number of other cost differences between a conventional facility and the "policy" facility. The additional capital costs for a biomass plant are assumed to be $20 million,[50] based on a 50-million-gallon-per-year (MMgal/year) plant capacity. The life span of an ethanol plant (assumed to be 15 years), coupled with an assumed interest rate of 5%, gives a capital recovery factor of 0.096 (i.e., a $20 million plant is assumed to cost $1,926,846 per year over the life of the project). Other additional expenses for a biomass facility compared with a natural gas facility include additional maintenance costs ($180,000 per 50

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[50] Based on personal communications with Bill Lee, Chippewa Valley Ethanol Company.

MMgal/year),[51] costs associated with ash disposal ($80,000 per 50 MM gal/year), and emission control measures to counter sulfur ($12,000 for 20 MMgal/year).

Note that the economical and technical feasibility of using renewable energy as a replacement to conventional energy was not considered as a part of this analysis.

GHG Reductions Through Gasoline and Fossil Diesel Displacement With Superior Feedstocks and Processes

A study on life-cycle GHG benefits for biodiesel production and use was used to estimate the CO_2e reductions for this policy (Hill et al., 2006).[52] This study covered biodiesel production from soybean production, which is currently the predominant feedstock source for U.S. biodiesel production and is assumed to remain so for the purposes of this analysis. Life-cycle CO_2e reductions (via displacement of fossil diesel with soybean-derived biodiesel) were estimated by Hill et al. to be 41%.

For this policy recommendation, the additional incremental benefit of in-state production is derived from the lower embedded GHG footprint of biodiesel feedstocks (vegetable oil) avoided from having to transport the feedstocks from their likely source region. While Minnesota has a significant in-state domestic soybean industry, for this assessment the potential alternative source regions for soybean or canola oil are the U.S. Midwest or Northern Plains regions, with rail transport shipments to central Minnesota estimated at about 350 miles.[53] Rail fuel consumption is about 400 ton-miles/gallon.[54] The density of vegetable oil is about 3,700 tons/MMgal. From these inputs, a GHG emission rate of 33 $MtCO_2e$/MMgal oil was calculated.

When combined with the other feedstocks needed to produce biodiesel (e.g., either methanol or ethanol),[55] 1 gallon of vegetable oil will produce slightly more than 1 gallon of biodiesel. For the purposes of this estimate, each gallon is assumed to produce 1 gallon of biodiesel.

For oil sources other than soybean oil, the benefit for substituting in-state biodiesel for fossil diesel is estimated starting with the life-cycle soybean emission factor (7,261 $MtCO_2e$/MMgal from the Hill et al. study).

The benefits of the biodiesel component will be considered by the TLU/Energy Supply (ES) low-carbon fuel option, and is based on displacement with soybean-based biodiesel. Additional benefits occur through the development of in-state feedstock (oil) production using GHG-

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[51] D. Nicola, "Comparison of Capital Costs for Ethanol Plants," in D. Tiffany, *Fossil Fuels and Ethanol Plant Economics*, University of Minnesota, May 16, 2006. Accessed on December 28, 2007, at: www.mncpoe.org/Previous_events/Redwood_ppt/AURIEthanolPlantEnergyMay162006.pdf

[52] Hill et al. (2006), "Environmental, Economic, and Energetic Costs and Benefits of Biodiesel and Ethanol Biofuels," *Proceedings of the National Academy of Sciences* 103(30):11206–11210, July 25, 2006. See http://www.pnas.org/cgi/content/full/103/30/11099

[53] U.S. National Atlas at: http://nationalatlas.gov/natlas/Natlasstart.asp

[54] U.S. National Atlas at: http://nationalatlas.gov/articles/transportation/a_freightrr.html

[55] While the analysis here focuses on the primary feedstock for biodiesel—vegetable oil—the policy should also promote the production and use of alcohol feedstocks produced from renewable resources (e.g., starch or cellulosic ethanol, renewable methane to methanol).

preferential feedstocks. These include vegetable oils that produce greater volumes of oil per unit of energy input (e.g., canola), animal fats, and, in the future, algal oils.

Canola produces 127 gallons of oil per acre, compared with soybeans at 48 gallons/acre. Assuming canola production energy inputs are not significantly greater than soy, the life-cycle emission rate for canola would be 7,261 × 48/127 or 2,744 $MtCO_2e/MMgal$. So the additional benefit of canola over soy is 7,261 – 2,744 = 4,517 $MtCO_2e/MMgal$.

For animal fats and algal oils, it is assumed that these have negligible embedded energy. So the incremental benefit over soy equals the life-cycle fossil diesel emission factor (EF) (12,306 $MtCO_2e/MMgal$) minus the soybean-based EF (7,261 $MtCO_2e/MMgal$), which is 5,045 $MtCO_2e/MMgal$.

To meet the in-state production goals for 2025, Table I-12 provides the mix of oil feedstocks assumed in this analysis, based on the availability of feedstocks obtained from BioPET. The assumed mix relies on new technologies (e.g., algal oil) to produce feedstocks post-2015. The new production data summarized in Table I-12 exclude BAU production, which is currently approximately 63 MMgal/year, of which only about 3 MMgal are from animal oil feedstocks.[56] The 2015 and 2025 totals are based on existing production capabilities and available feedstocks obtained from BioPET.

BAU production is further assumed to be soybean-based, with little incremental benefit above TLU-3.

Table I-12. Biodiesel feedstocks and shares of production

Year	Oil Feedstock	Fraction of New Production	MMgal/year Needed*
2015	Soy	85%	32
2015	Canola	0%	0
2015	Animal	15%	6
2015	Algal	0%	0
2015 Total			**37**
2025	Soy	60%	57
2025	Canola	5%	5
2025	Animal	30%	28
2025	Algal	5%	5
2025 Total			**94**

MMgal = million gallons.

* 2015 and 2025 totals calculated using policy design goals.[57]

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[56] Based on Su Ye, "Economic Impact of Soy Diesel in Minnesota," Agricultural Marketing Services Division, Minnesota Department of Agriculture, September 11, 2006. See http://www.bioenergyaustralia.org/newsletters/news16.htm

[57] Assumes production needed is additional to existing in-state production.

GHG reductions were estimated by multiplying the production of each oil feedstock by the applicable incremental benefit (e.g., by oil type). Total reductions in each year were estimated by summing the incremental benefit for each oil type and the life-cycle emission benefits estimated above.

For gasoline displacement, the benefits for this policy are dependent on developing in-state production capacity that achieves benefits above the levels of conventional U.S. starch-based production. Emission factors for reformulated gasoline, starch-based ethanol, and cellulosic ethanol were taken from a General Motors/Argonne National Laboratory (GM/ANL) study.[58] These emission factors incorporate the GHG emissions during the entire life cycle of fuel production (e.g., for gasoline: extraction, transport, refining, distribution, and consumption; for ethanol: crop production, feedstock transport, processing, distribution, and consumption). These life-cycle emission factors are referred to as "well-to-wheels" emission factors.

Table I-13. Life-cycle emission factors for gasoline and ethanol

Fuel	Emission Factor (grams CO_2e/mile)
Reformulated gasoline	552
Starch-based ethanol	451
Cellulosic ethanol	154

CO_2e = carbon dioxide equivalent.

In addition to cellulosic ethanol production, the other types of ethanol production processes targeted by this policy include starch-based processes that achieve levels of life-cycle GHG reductions similar to those of cellulosic ethanol. These would be starch-based plants that use renewable fuels, such as biomass, biogas, landfill gas (LFG), or other renewable fuels. While CCS is not aware of any life-cycle emission factors for these types of plants (although several have been proposed in the United States), it is assumed that reductions similar to cellulosic ethanol can be achieved. The life-cycle GHG benefits of any biofuel will depend on the type of material (e.g., cellulosic, annual/perennial) used and the feedstock growing/harvesting practices employed.

Based on the emission factors shown in Table I-13, the incremental benefit of the production targeted by this policy over conventional starch-based ethanol is 66% (reduction of CO_2e by offsetting gasoline consumption). This value was used to estimate GHG reductions, along with the life-cycle emission factor for gasoline[59] and the production in each year.

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[58] N. Brinkman, M. Wang, and T. Weber (2005), *Well-to-Wheels Analysis of Advanced Fuel/Vehicle Systems: A North American Study of Energy Use, Greenhouse Gas Emissions, and Criteria Pollutant Emissions,* Technical Analysis Reports, Argonne, IL: Argonne National Laboratory, 2005. Available at http://www.transportation.anl.gov/pdfs/TA/339.pdf

[59] In the GM/ANL study, the average fuel economy used was 21.3 miles/gallon, or 100 miles/4.7 gallons. Multiplying this value by the emission factor of 552 grams/mile yields 11,745 grams/gallon.

Currently, there is significant ethanol production in Minnesota, with 16 ethanol plants and an annual production capacity of approximately 620 million gallons[60]—approximately 13% of the total U.S. output. An additional four plants are under construction, with another 400 million gallons of capacity.[61] Three plants under construction are expected to start up by March 2008, and the fourth by October 2008. Once construction of these facilities is complete, Minnesota's total ethanol production capacity will be over one billion gallons of ethanol per year. About half of the state's total annual ethanol production is exported. The GHG benefit quantification assumes that additional cellulosic ethanol production is required to meet this policy's goals. Cellulosic ethanol production required by existing policies has been incorporated into the analysis and assists the state with meeting the targets under this policy.[62]

Cost of Gasoline and Fossil Diesel Displacement With Superior Feedstocks and Processes
For the biodiesel component, the value of incentives needed is assumed to be equivalent to the incentive offered in a Missouri state incentives program.[63] This program offers production incentives of $0.30/gallon to producers up to 15 million gallons of production/year. The incentive grants last for 5 years.

It is assumed a similar incentive structure that would cover the costs of all grants or tax incentives associated with this policy (all other implementation mechanisms are assumed to be achieved within existing programs). The cost estimates are based on multiplying the amount of biodiesel produced in each year by the production incentive. This assumes that all production occurs at production facilities of less than 15 MMgal/year. The production incentive expires after 5 years of production.

For the gasoline component, costs for the incentives needed by this policy are based on the difference in estimated production costs between conventional starch-based ethanol and cellulosic ethanol. EIA estimated that the cost to produce starch-based ethanol is $1.10/gal, compared with $1.29/gal, or a difference of $0.19/gal in 1998 dollars;[64] in 2007 dollars, the difference is $0.24/gal. These incentives are considered necessary in the near term (up to 2015) to help commercialize technologies that produce ethanol from cellulose or that produce starch-based ethanol using renewable fuels. The incentives should also help to establish the

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[60] From Minnesota Pollution Control Agency, Minnesota Department of Natural Resources, Minnesota Department of Agriculture, Minnesota Department of Employment and Economic Development, Minnesota Department of Transportation, Minnesota Department of Commerce, and Minnesota Department of Health, *Planning and Constructing an Ethanol Plant: A Guidance Document,* August 2007 (revised). See http://www.pca.state.mn.us/publications/ethanol-guidancedoc.pdf

[61] From personal communications with Ralph Groschen, Agriculture Marketing Specialist, MDA.

[62] Minnesota requires that all gasoline sold in the state be blended with a 20% ethanol mix by 2013. Of this, the state has a goal of deriving a quarter of the RFS from cellulosic-derived biofuel by 2015, or when 60,000,000 gallons come online, whichever is first. For this analysis, the existing policy cellulosic requirements is assumed to be fulfilled from 2013.

[63] Information on the Missouri program is available from Institute for Local Self-Reliance, New Rules Project, "Ethanol and Biodiesel Incentives—Missouri." See www.newrules.org/agri/mobiofuels.html#biodiesel, accessed January 2007.

[64] DOE, EERE, Office of Energy Statistics, "Biofuels in the U.S. Transportation Sector," February 2007. See www.eia.doe.gov/oiaf/analysispaper/biomass.html

infrastructure to deliver biomass to biorefineries, since producers will seek the local feedstocks or renewable fuels for their operations.

By 2015, it is assumed that advances in cellulosic ethanol production (e.g., enzyme costs, production processes) will make cellulosic ethanol production cost-competitive with starch-based production. Hence, the incentives are discontinued beginning in 2016. Note that a current federal legislative proposal is offering cellulose an incentive of $0.765/gal, compared with the $0.51/gal currently offered for ethanol production.[65] If enacted, this $0.255/gal premium could cover the additional incentives that are assumed to be needed by Minnesota. Obviously, the federal incentives do not ensure that production facilities will locate in Minnesota; therefore, these incentives have not been factored into the cost estimates for this policy.

The costs for this policy were estimated using the $0.24/gal incentive multiplied by the production needed in each year. By 2015, it is assumed that these incentives will no longer be needed, as cellulosic ethanol technologies become fully commercialized. The assumed schedule for these incentives and the emissions saved for each year are shown in Tables I-14a–14c.

Table I-14a. Costs and benefits of offsetting gasoline with ethanol (50%)

Year	EtOH Production Needed (10^6 Btu)	MMgal EtOH Capacity Needed[66]	Costs (MM$)	Discounted Cost (MM$)	Avoided Emissions MMt (Cellulosic Compared With Corn)*
2008	7,433,356	88	$21.3	$20.3	0.56
2009	14,401,100	171	$41.3	$37.4	1.08
2010	20,880,986	248	$59.8	$51.7	1.57
2011	26,865,123	319	$77.0	$63.3	2.01
2012	35,419,344	420	$102	$79.5	2.66
2013	40,713,602	483	$117	$87.1	3.05
2014	51,099,220	606	$147	$104	3.83
2015	61,762,279	733	$177	$120	4.63
2016	72,637,515	862	$0.0	$0.0	5.45
2017	83,779,775	994	$0.0	$0.0	6.28
2018	95,194,097	1,130	$0.0	$0.0	7.14
2019	106,885,605	1,268	$0.0	$0.0	8.02
2020	118,859,507	1,411	$0.0	$0.0	8.91
2021	130,863,772	1,553	$0.0	$0.0	9.81
2022	143,112,390	1,698	$0.0	$0.0	10.73
2023	155,609,227	1,847	$0.0	$0.0	11.67
2024	168,358,206	1,998	$0.0	$0.0	12.63

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[65] D. Morris, *Making Cellulosic Ethanol Happen: Good and Not So Good Public Policy*, Institute for Local Self-Reliance, January 2007, available at: www.newrules.org/agri/cellulosicethanol.pdf

[66] Calculated by converting the EtOH capacity needed from Btu's into gallons (ethanol heat content 84 MMBtu/1,000 gal, from Minnesota I&F Transport projections) and adjusting for the existing cellulosic ethanol fuel requirement.

Year	EtOH Production Needed (10^6 Btu)	MMgal EtOH Capacity Needed[66]	Costs (MM$)	Discounted Cost (MM$)	Avoided Emissions MMt (Cellulosic Compared With Corn)*
2025	181,363,303	2,152	$0.0	$0.0	13.6
			Cumulative	**$563**	**114**

EtOH = ethanol; Btu = British thermal unit; MMgal = million gallons; MM$ = million dollars; MMt = million metric tons.

* Note that the greenhouse gas (GHG) benefits displayed here do not incorporate any overlap with the Transportation and Land Use Low-Carbon Fuel Standard (TLU-3).

Table I-14b. Costs and benefits of offsetting gasoline with ethanol (35%)

Year	EtOH Production Needed (10^6 Btu)	MMGal EtOH Capacity Needed[67]	Costs (MM$)	Discounted Cost (MM$)	Avoided Emissions MMt (Cellulosic Compared With Corn)*
2008	4,713,836	56	$13.5	$12.9	0.35
2009	8,890,475	106	$25.5	$23.1	0.67
2010	12,506,259	148	$35.8	$31.0	0.94
2011	15,545,548	184	$44.6	$36.7	1.17
2012	21,075,657	250	$60.4	$47.3	1.58
2013	23,264,915	276	$66.7	$49.8	1.74
2014	30,462,997	362	$87.3	$62.0	2.28
2015	37,854,300	449	$109	$73.4	2.84
2016	45,398,447	539	$0.0	$0.0	3.40
2017	53,128,638	631	$0.0	$0.0	3.98
2018	61,048,388	725	$0.0	$0.0	4.58
2019	69,161,274	821	$0.0	$0.0	5.19
2020	77,470,929	919	$0.0	$0.0	5.81
2021	85,812,309	1,018	$0.0	$0.0	6.44
2022	94,324,075	1,119	$0.0	$0.0	7.07
2023	103,008,925	1,222	$0.0	$0.0	7.73
2024	111,869,597	1,328	$0.0	$0.0	8.39
2025	120,908,868	1,435	$0.0	$0.0	9.07
			Cumulative	**$336**	**73**

EtOH = ethanol; Btu = British thermal unit; MMgal = million gallons; MM$ = million dollars; MMt = million metric tons.

Note: Approximate biomass required under 35% displacement is 5 million tons in 2015 (assuming 90 gal/ton) and 14.3 million tons in 2025 (assuming 100 gal/ton).

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[67] Ibid.

Table I-14c. Costs and benefits of offsetting gasoline with ethanol (20%)

Year	EtOH Production Needed (10^6 Btu)	MMGal EtOH Capacity Needed[68]	Costs (MM$)	Discounted Cost (MM$)	Avoided Emissions MMt (Cellulosic Compared With Corn)*
2008	1,994,315	24	$5.7	$5.4	0.15
2009	3,379,850	40	$9.7	$8.8	0.25
2010	4,131,532	49	$11.8	$10.2	0.31
2011	4,225,974	50	$12.1	$10.0	0.32
2012	6,731,970	80	$19.3	$15.1	0.50
2013	5,816,229	69	$16.7	$12.4	0.44
2014	9,826,773	117	$28.2	$20.0	0.74
2015	13,946,321	166	$40.0	$27.1	1.05
2016	18,159,379	216	$0.0	$0.0	1.36
2017	22,477,500	267	$0.0	$0.0	1.69
2018	26,902,680	319	$0.0	$0.0	2.02
2019	31,436,943	373	$0.0	$0.0	2.36
2020	36,082,350	428	$0.0	$0.0	2.71
2021	40,760,847	484	$0.0	$0.0	3.06
2022	45,535,760	540	$0.0	$0.0	3.41
2023	50,408,623	598	$0.0	$0.0	3.78
2024	55,380,989	657	$0.0	$0.0	4.15
2025	60,454,434	717	$0.0	$0.0	4.53
			Cumulative	**$109**	**33**

EtOH = ethanol; Btu = British thermal unit; MMgal = million gallons; MM$ = million dollars; MMt = million metric tons.

Note: Approximate biomass required under 20% displacement is 1.8 million tons in 2015 (assuming 90 gal/ton) and 7.2 million tons in 2025 (assuming 100 gal/ton).

This policy is closely related to TLU-3 (Low-GHG Fuel Standard). AFW-3 focuses on the supply elements of the implementation of a biofuels program, while TLU-3 focuses on the demand side (e.g., vehicle technology, E10, E85). While it is assumed that there is 100% overlap with TLU-3, additional analysis is required to determine the appropriate amount of overlap. This additional analysis was not conducted with the time and resources available for producing this report.

Key Assumptions:

This analysis assumes that life-cycle GHG emission factors utilized/derived for this analysis are representative for each feedstock and for fossil diesel; the production incentives offered by this policy are sufficient to drive production of GHG-superior feedstocks (e.g., superior to soybeans) and to increase the level of research and development needed for noncrop-based feedstocks (e.g., algal biodiesel, Fischer-Tropsch biodiesel); starch-based ethanol production using renewable fuels achieves GHG life-cycle benefits equivalent to those from cellulosic ethanol; cellulosic production or starch-based production with renewable fuels can achieve the production levels in

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[68] Ibid.

the near term required by this policy; and federal tax incentives do not preclude the need for the additional state incentives assumed for the cost estimate.

While Minnesota is a significant ethanol producer, for the purposes of quantification, the quantity of ethanol required by this policy assumes that additional cellulosic ethanol production is required to meet the policy's goals. Cellulosic ethanol production required by existing policies has been incorporated into the analysis, and helps the state meet the targets under this policy. Additionally, while this analysis is focused on ethanol, the goal is not specific to ethanol and could include alternative biofuel options that may be developed by industry in the future.

The economical and technical feasibility of replacing conventional energy with renewable energy was not considered as a part of this analysis; it was assumed that sufficient supply was available to meet the demand set by the policy. The cost and GHG impact of replacing plant nutrients lost to harvested cellulous materials were also not considered.

This analysis also assumes that sustainable quantities of the feedstocks are available at an economic price, and water is available for appropriate facility location. Initial analysis indicates that sufficient biomass is available to supply the feedstock requirements under both AFW-3 and AFW-4. Based on data obtained from BioPET, approximately 29 million dry tons per year (or 461 trillion Btu's) are technically available from biomass residue/waste and energy crop, the majority (77%) of which comes from corn stalk. Assuming 100 gallons of ethanol can be processed from a ton of cellulosic feedstock,[69] sufficient corn stalk is available to meet the ethanol capacity needed to meet the 2025 goal, and the remaining feedstocks could be used to meet the biomass-to-energy goal (AFW-4).

Key Uncertainties

Substantial assumptions are involved in the analysis, as data in some areas are relatively unknown. The validity and accuracy of these assumptions are key uncertainties. This analysis is particularly sensitive to the relative fuel prices (e.g., natural gas versus biomass). Future energy prices are relatively uncertain, and natural gas prices in particular are extremely volatile. Different assumptions of energy prices will result in different cost outcomes.

Current energy and commodity markets are extremely volatile. The impact of developments in these markets on the applicability of the foregoing analysis is uncertain.

The potential impact of research developments on conversion costs of biomass is crucial.

The trade-off between scale economies in biomass conversion plants and the cost of transporting bulky biomass materials will be a key in development.

Vernon R. Eidman[70] has highlighted the uncertainty surrounding the costs of biomass-fired plants, stating that "firing the boiler with corn stover, dried distillers grains with solubles

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[69] The 2025 ethanol capacity needed is 2,152 million gallons, which would require about 21.5 million tons of cellulosic feedstock (based on 100 gal/ton biomass).

[70] V.R. Eidman, "Ethanol Economics of Dry Mill Plants." In *Corn-Based Ethanol in Illinois and the U.S. (2007): A Report From the Department of Agricultural and Consumer Economics*, Ch. 3, University of Illinois Urbana-Champaign, November 2007. See http://www.farmdoc.uiuc.edu/policy/research_reports/ethanol_report/Ethanol Report.pdf

(DDGS) and other biomass is experimental at this time and investment cost data for these alternative fuels are not available." Additional information will be revealed as new projects and research continue.

The full costs for capital, public incentives, education, standards, and monitoring have not been included in this analysis, and must be part of the cost calculus prior to policy enactment.

Additional Benefits and Costs

None identified.

Feasibility Issues

An initial assessment has indicated that there is a sufficient resource to meet the MCCAG biomass policy recommendations, although the margin declines throughout the policy period.

Status of Group Approval

Complete.

Level of Group Support

Super Majority (4 objections).

Barriers to Consensus

MCCAG members were concerned that a 35% gasoline displacement goal would stretch the state's agronomic and biomass resources, and noted that additional and potentially significant impacts should be evaluated regarding availability of land and water, consequences for food production, and changes in overall fuel costs. The MCCAG recommends that the University of Minnesota and other experts, through the Initiative for Renewable Energy, study the biofuels goals and the low-carbon fuel standard contained in AFW-3 and TLU-3. The study should analyze the feasibility of the proposals for reducing CO_2 emissions, as well as their impacts on land and water use, food production, fuel costs and availability, and the economic impacts on consumers and businesses.

AFW-4. Expanded Use of Biomass Feedstocks for Electricity, Heat, or Steam Production

Policy Description

This policy dedicates a sustainable quantity of biomass from agricultural lands, land restoration activity, agricultural industry residues, wood industry process residues, those normally unused forestry residues, and agroforestry resources for efficient conversion to energy and economical production of heat, steam, or electricity. This biomass should be used in an environmentally acceptable manner, considering proper facility siting and feedstock use (e.g., proximity of users to biomass, impacts on water supply and quality, control of air emissions, solid waste management, cropping management, nutrient management, soil and non-soil carbon management, and impacts on biodiversity and wildlife habitat). The objective is to create concurrent reduction of CO_2 due to displacement of fossil fuel considering life-cycle GHG emissions associated with viable collection, hauling, and energy conversion and distribution systems.

The potential feedstocks associated with this policy are biomass normally unused under any existing program, meaning:

- Any organic material grown for the purpose of being converted to energy.
- Any organic by-product of agriculture that can be converted into energy.
- Any material that can be converted into energy and is non-merchantable for other purposes, that is segregated from other non-merchantable material, and that is:
  - A forest-related organic resource, including mill residues, pre-commercial thinnings, slash, brush, or by-product from conversion of trees to merchantable material; or
  - A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically treated, or painted wood products), and landscape or right-of-way tree trimmings.

Expanded biomass resources can be developed from agricultural industry process residues and agroforestry products as new industrial facilities are built and through conversion of existing facilities. Analyses project that Minnesota theoretically has enough residual biomass and energy crops that, if collected and fed to the most efficient conversion technologies available, could produce up to 99% of the total electricity currently used in the state. Actual results are highly dependent on economically attractive methods for collection of materials, hauling, and energy conversion and distribution systems, as well as sustainable harvest methods. Current research and increasing numbers of demonstration projects occurring nationally are available to determine which system components are most functional and cost-effective for given locations.

The policy will address the following needs:

- Provide resources to advance the rate of development of domestic biomass yield through research and development without compromising the soil carbon stability and long-term viability of the production area, and to develop standards and methods to measure the ecological sustainability and economical aspects of yield and harvest methods.

- Advance energy collection and conversion technologies for a range of applications, from farm-scale point of use to larger industrial-size units designed for specific use. Design collection and conversion processes to maximize overall GHG reductions through life-cycle analysis.
- Provide market incentives to develop a Minnesota biomass-to-energy conversion equipment industry and to enhance market infusion of biomass conversion products.
- Provide a focus on high-potential, low-cost actions that do not create an adverse effect on the forest industry, or on existing forestry or agricultural practices.
- Ensure that the current raw material supplies of established forest product firms are sustained, and the existing use of biomass by these firms for energy purposes is enhanced.
- Structure incentives to enable partnerships to develop between electric utilities and the forest products industry to increase the potential pool for investment capital and promote least-cost compliance with the state's aggressive renewable electricity requirements.

Policy Design

Goals:

Energy Crop Production
By 2015, have 40,000 acres of land producing high-MMBtu and ecologically sustainable energy crops near energy facilities. By 2025, have 120,000 acres of these crops in production. Energy in biomass from these acres is considered to be included in the biomass Btu utilization goal.

Biomass Utilization
Increase beyond existing programs the use of normally unused biomass for renewable energy (heat, steam, or electricity) generation to 16,000 billion Btu's per year by 2015 and 46,000 billion Btu's per year by 2025.

Timing: See above.

Parties Involved: Review and analysis of power sector industry restructuring issues must include consultation with affected and interested parties, including representatives of area land planners, rural and other energy consumers (commercial, industrial, small), investor-owned cooperatives and municipal utilities, local units of government, the Minnesota Pollution Control Agency (MPCA) and local environmental agencies, renewable energy developers and providers, natural gas distribution utilities, community action agencies, the Minnesota Public Utilities Commission (PUC), agro industries with waste products, forest-product industries with waste products, conservation groups, the Minnesota Forest Resources Council (MFRC), the Minnesota Board of Water and Soil Resources (BWSR), the Minnesota DNR, MDA, researchers at the University of Minnesota, and AURI.

Other: Not applicable.

Implementation Mechanisms

Focus on high-potential, low-cost actions that do not adversely affect existing agriculture and forestry practices.

Act on energy recommendations from the 2007 Governor's Task Force on the Competitiveness of Minnesota's Primary Forest Products Industry.[71] These include the following biomass energy recommendations for the NextGen Energy Board:

- Ensure that existing forest product industry facilities are a priority for state cellulosic biofuels and bioenergy policies, incentives, and research.
- Ensure that the current raw material supplies of established forest product firms are sustained, and the existing use of biomass by these firms for energy purposes is enhanced.
- Provide capital incentives for high-value biomass utilization, including gasification equipment to produce biogas, as an offset for the use of natural gas and propane, and as a first step toward the next generation of biofuels.
- Structure incentives to enable partnerships to develop between electric utilities and the forest products industry, in order to increase the potential pool for investment capital and promote least-cost compliance with the state's aggressive renewable electricity requirements.
- Provide state investment in pilot-scale projects at existing forest products facilities to test next-generation bioenergy technologies (NextGen Board).

By 2015, establish criteria and standards for the sustainable harvest and utilization of agricultural and forest residues. Build on Minnesota Forest Stewardship Council (FSC) guidelines and other MFRC, RIM-CE, and MDA guidelines for residue removal to ensure soil health and soil carbon storage.

Create strong efficiency incentives on both the heat and the electricity sides to reduce the land-use pressures for biomass development in meeting the energy goals.

Plant energy crops so the feedstock is available. Pilot projects may be needed in the near term to assess the economics of broader-scale commercialization in the long term (i.e., via RIM-CE).

Allot funds for developing sustainability standards to fill the research gaps identified by the MFRC on its woody biomass residue harvest guidelines, and establish agricultural-sector energy crops (i.e., via BWSR programs).

Create an MMBtu energy incentive to allow biomass conversion facilities to install biomass feedstock acceptance (conveyers, etc.) to address their storage needs. An MMBtu incentive is preferable, as it encourages the input of high-MMBtu feedstocks and efficient conversion of the biomass into energy (for a high-MMBtu output). This performance-based incentive would be

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[71] Iron Range Resources, *Report to the Governor: Governor's Task Force on the Competitiveness of Minnesota's Primary Forest Products Industry,* Eveleth, MN, July 2007. The full text of the report can be accessed at: www.ironrangeresources.org. Click on Natural Resources, then on Forest Products, then on More Forestry Information.

technology neutral (i.e., it could be used for gasifiers, or whatever technology is developed in this rapidly changing market).

Develop a template for a contract between facilities and farmers/intermediary/co-op, to minimize risk for both parties (e.g., if farmer can't meet long-term contractual needs).

Related Policies/Programs in Place

The Renewable Electricity Standard became Minnesota law in February 2007. It requires that 30% of the electricity sold by Xcel Energy to Minnesota consumers be renewable by 2020; for all other utilities, 25% must be renewable by 2025. Under the new standard and efficiency legislation passed, Minnesota will most likely add 5,000–6,000 megawatts (MW) of new renewable electricity to its system.

Xcel Energy has a mandate to purchase 110 MW of biomass electricity. Currently, it has fulfilled that mandate with the St. Paul District Energy facility, the FibroMinn turkey litter project, and the Virginia/Hibbing biomass project. There is not expected to be space available within this mandate for further projects.

RIM-CE is a working-lands program within BSWR that allows for growing and harvesting of bioenergy crops with added payments for increased conservation and water quality benefits. The program still needs funds for granting easements for bioenergy crops.

There are currently multiple grant opportunities for biomass facility feasibility and project development, including granting authority from MnDOC, the Renewable Development Fund, and MDA (via the NextGen Energy Board). Similarly, there are multiple existing and planned bioenergy heat and power projects in Minnesota, including:

- A gasification plant that is planned for the University of Minnesota at Morris will use crop waste (corn stover) to produce heat, electricity, syngas, and/or hydrogen. The University of Minnesota Duluth's Coleraine Lab has obtained a grant to develop a gasification project that will convert wood waste to hydrogen.
- Researchers at the University of Minnesota's Southern Research and Outreach Center are analyzing the suitability of various woody plant species for biomass yield and their suitability for various soil types and elevations.
- The Center for BioRefining at the University of Minnesota has developed a biomass/hydrolysis process that converts waste biomass, such as corn stover, into bio-oil that can be used to make polymers for products and hydrogen-rich gas.
- St. Paul District Energy provides over 80% of power for downtown St. Paul from woody biomass. Also, Minnesota Power in Duluth has a large biomass-to-energy plant.
- Numerous other projects include Koda Energy, Central Minnesota Ethanol Cooperative, Chippewa Valley Ethanol Company, and municipal energy projects.
- For certification, The Laurentian Energy Authority (Virginia/Hibbing) Biomass Energy Project has provided $150,000 each to the MFRC to establish guidelines for the sustainable removal of woody biomass from forests for energy and to the Minnesota DNR to develop

similar guidelines for brushlands and open lands. The MFRC identified existing research gaps and may need an increased allotment of funds to further refine the standards being developed. The guidelines have been developed and approved and will be published early in 2008. The 2007 Minnesota legislature provided $300,000 to the MFRC to fund research on the ecological impacts of woody biomass removal for energy.

Type(s) of GHG Reductions

CO_2, N_2O, CH_4: Displaces emissions from fossil fuel combustion.

Estimated GHG Reductions and Net Costs or Cost Savings

GHG Reduction Potential in 2015, 2025 ($MMtCO_2e$): 1.3, 3.8, respectively.

Net Cost per tCO_2e Reduced: $3.

The above represents a stand-alone analysis. For the results shown at the bottom of the summary table at the front of this document, it is assumed that there is 100% overlap with the biomass policies incorporated under the Energy Supply (ES-3, ES-5) and Residential, Commercial, and Industrial (RCI-4) sector policies.

Data Sources:

- Center for Energy and Environment, *Identifying Effective Biomass Strategies: Quantifying Minnesota's Resources and Evaluating Future Opportunities*, Minneapolis, MN, 2007. Funded by Xcel Energy's Renewable Development Fund. Layering maps for project siting, the report, and project feasibility spreadsheet are available at: http://www.mncee.org/public_policy/renewable_energy/biomass/index.php
- Shalini Gupta, "Plant Power: Biomass-to-Energy for Minnesota Communities," May 14, 2004, prepared for Fresh Energy (Minnesotans for an Energy-Efficient Economy at the time) and MnDOC, available at: http://www.state.mn.us/mn/externalDocs/Commerce/ME3_Biomass_Report_110204031416_BioMass2004.pdf
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Quantification Methods:

Energy Crop Production
For quantification purposes, it is assumed that the additional energy crop acreage prescribed by this goal is a potential feedstock to achieve the biomass Btu utilization goal. As such, the quantification of this goal is considered to be included under the biomass utilization quantification below.

Biomass Utilization GHG Benefits
This policy calls for 16,000 billion Btu's of biomass energy per year by 2015 and 46,000 billion Btu's per year by 2025, to be used to offset fossil fuel combustion in the ES and RCI sectors. The benefit of the utilization of this additional biomass assumes that the biomass is used to offset the consumption of fossil fuels. It is assumed that half of the available biomass will be utilized in the electricity sector, and the other half in the RCI sector. Based on the existing fuel mix, it is assumed that in the electricity sector biomass will offset coal, while the RCI sector biomass will offset 50% coal and 50% gas.[72] The amount of biomass available is outlined in Table I-15, using BioPET,[73] and indicates that sufficient biomass is available to meet the prescribed goals.

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[72] Different benefits would occur if an alternative fuel mix were used or other fuels like oil were offset.

[73] The Center for Energy and Environment's BioPET software was used. This software is an Excel spreadsheet that contains information on the biomass available at the county level.

Table I-15. Biomass available (from BioPET)

Feedstock	Dry Tons/Year	Btu/lb	MMBtu	Percent of Total
Hay/straw non-CRP	2,321,987	7,600	35,294,204	7.7%
Switchgrass/other	1,007,905	7,481	15,080,276	3.3%
Corn stalk	21,680,081	8,191	355,163,090	77.1%
Sunflower stalk	45,846	8,191	751,056	0.2%
Hay/straw from CRP lands	1,955,457	7,375	28,842,991	6.3%
Unprocessed logging residues	1,016,359	8,669	17,621,632	3.8%
Mill residues	595,099	6,757	8,042,173	1.7%
Total	**28,622,735**		**460,795,422**	**100.0%**

Btu/lb = British thermal units per pound; MMBtu = million British thermal units.

The GHG benefits were calculated by the difference in emissions associated with each of the input fuels (0.0959 tCO_2e/MMBtu for sub-bituminous coal, 0.0539 tCO_2e/MMBtu for natural gas, and 0.0019 tCO_2e/MMBtu for biomass, including non-CH_4 and non-N_2O emissions).[74]

This policy directly overlaps with policies considered under the ES and RCI sectors. The biomass energy requirements under the ES and RCI policies are greater than the requirement under this policy. To avoid double counting emission reductions, the GHG benefits from this policy are assumed to be captured under the ES and RCI policies.

This policy also overlaps and interacts with AFW-2. It focuses on the GHG benefits associated with the displacement of fossil fuel, whereas AFW-2 (particularly the RIM-CE component) focuses on the carbon storage benefits of energy crops.

Biomass Utilization Costs

The cost analysis for this policy is based on the difference in costs between supply of woody biomass fuel and the assumed fossil fuel that it is replacing (i.e., the relevant proportions of coal and gas outlined above). The cost was assumed to be $5/MMBtu for natural gas and $1.74/MMBtu for coal.[75] The cost of biomass was assumed to be $47/ton.[76] This equates to $3/MMBtu for biomass.[77] The cost is calculated by assuming the replacement of coal and gas with biomass, as indicated in Table I-16 in MMBtu. The difference in cost of supply between biomass and coal and biomass and gas is calculated using the costs above. The difference in costs ($/MMBtu) is multiplied by the amount of energy (MMBtu) being replaced by biomass based on the fuel mix in the electricity and RCI sectors. The BAU fuel mix is assumed to be 100% coal in the electricity sector and 50% coal and 50% gas in the RCI sector. (It is assumed

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[74] Emission factors obtained from CCS Minnesota Energy Supply GHG forecasts.

[75] DOE, EIA, National Energy Modeling System. Data from EIA were averaged over the policy period. DOE, EIA, *Annual Energy Outlook 2007: With Projections to 2030,* IDOE/EIA-0383(2007), Washington, DC, February 2006. Available at: http://tonto.eia.doe.gov/ftproot/forecasting/0383(2007).pdf

[76] Cost per dry ton for dry Herbaceous Biomass Feedstock Collection, Preprocessing, and Delivery to Conversion Reactor Inlet, sourced from DOE, EERE, Biomass Program, *Biomass Program Multi-Year Plan*, October 2007, available at: http://www1.eere.energy.gov/biomass/publications.html

[77] Assumes heat content of biomass is 7,752 Btu/lb based on an average from BioPET.

that 50% of biomass will be utilized in the electricity sector and 50% in the RCI sector.) A summary of costs and avoided emissions for each year is presented in Table I-16.

Table I-16. Costs and avoided emissions

Year	Biomass (MMBtu)	Cost/Savings	Discounted Cost/Savings	Avoided Emissions (MMtCO$_2$e)
2008	2,000,000	$935,578	$891,026	0.167
2009	4,000,000	$1,871,155	$1,697,193	0.334
2010	6,000,000	$2,806,733	$2,424,561	0.501
2011	8,000,000	$3,742,310	$3,078,808	0.668
2012	10,000,000	$4,677,888	$3,665,247	0.835
2013	12,000,000	$5,613,465	$4,188,854	1.00
2014	14,000,000	$6,549,043	$4,654,282	1.17
2015	16,000,000	$7,484,620	$5,065,886	1.34
2016	19,000,000	$8,887,987	$5,729,275	1.59
2017	22,000,000	$10,291,353	$6,317,998	1.84
2018	25,000,000	$11,694,719	$6,837,660	2.09
2019	28,000,000	$13,098,085	$7,293,504	2.34
2020	31,000,000	$14,501,452	$7,690,429	2.59
2021	34,000,000	$15,904,818	$8,033,014	2.84
2022	37,000,000	$17,308,184	$8,325,533	3.09
2023	40,000,000	$18,711,551	$8,571,977	3.34
2024	43,000,000	$20,114,917	$8,776,072	3.59
2025	46,000,000	$21,518,283	$8,941,291	3.84
Total		**$185,712,140**	**102,182,610**	**31.5**

MMBtu = million British thermal units; MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

The cost estimates do not include capital costs for new equipment purchases or retrofits. It is assumed that changes in equipment use occur after the useful life of existing fossil fuel-fired equipment. The up-front cost of a biomass combustion system can be greater than a traditional system; however the fuel is far less expensive, such that, over time, fuel savings can more than offset up-front costs. Net cost savings are more likely in certain circumstances, in particular: (1) when the price of fossil fuel equipment options are relatively expensive and (2) in larger, heat-using facilities whose unit savings on heating fuel costs result in a better payback on the up-front investment.

While it is assumed that there is 100% overlap with the policies under ES-3, ES-5, and RCI-4, additional analysis is required to determine the appropriate amount of overlap. This additional analysis was not conducted with the time and resources available for this report.

Key Assumptions:

The benefit of the utilization of this additional biomass assumes that the biomass is used to offset a combination of gas and coal (different benefits would occur if an alternative fuel mix or other fuels like oil were offset). The emission factor developed for Minnesota biomass delivery does not include emissions for equipment used for on-site collection and processing of biomass due to a lack of information. All biomass under this policy is utilized by the RCI or ES policies.

The removal of biomass residue could reduce nutrient input and, as a result, could reduce biomass yield. This analysis does not incorporate any reduction in biomass production that may result from reduced nutrient input, nor does it incorporate the potential costs of replacing plant nutrients due to removal of biomass materials.

Initial analysis indicates that sufficient biomass is available to supply the feedstock requirements under both AFW-3 and AFW-4. Based on data obtained from BioPET, approximately 29 million dry tons per year (or 461 trillion Btu) are technically available from biomass residue/waste and energy crop, the majority (77%) of which comes from corn stalk. Assuming 100 gallons of ethanol can be processed from a ton of cellulosic feedstock,[78] sufficient corn stalk is available to meet the ethanol capacity needed to meet the 2025 goal, and the remaining feedstocks could be used to meet the biomass-to-energy goal (AFW-4). The reader is also directed to the initial assessment of biomass resource availability presented at the beginning of this appendix.

Key Uncertainties

As identified under key assumptions.

Additional Benefits and Costs

None identified.

Feasibility Issues

- Expanded biomass resources can be developed from agricultural industry process residuals and agroforestry products as new industrial facilities are built and through conversion of existing facilities. Analyses project that theoretically residual biomass and energy crops in Minnesota are sufficient that, if collected and fed to the most efficient conversion technologies available, they could produce a percentage of the energy currently used in Minnesota. Actual results are highly dependent on economically attractive methods for collection of materials, hauling, and energy conversion and distribution systems, as well as sustainable ecological harvest methods. Current research and increasing numbers of demonstration projects occurring nationally are available to determine which system components are most functional and cost-effective for given locations.
- Any action to expand use of biomass for energy conversion must consider ecological sustainability and standards for harvesting. In addition, actions must consider land-use limitations and resource needs for relatively scaled heat/power facilities. Removal of biomass, residue, or perennial removes plant nutrients essential for long-term productivity. Balancing this removal is critical for long-run biomass harvesting.
- Biomass feedstock has certain inherent physical and chemical characteristics. The fuel preparation steps must change the characteristics inherent in the feedstock into the

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[78] The 2025 ethanol capacity needed is 2,152 million gallons, which would require around 21.5 million tons of cellulosic feedstock (based on 100 gallons/ton biomass).

characteristics needed for the conversion device; thus, the feedstock requirements for the conversion device must be known.

- Various wood sources can have different physical and chemical characteristics that can greatly influence their conversion to energy. Feeding these materials with differing characteristics as slugs into the conversion device can cause rapid changes in operating conditions, and can make control difficult. Even wood sources differing only in moisture content can cause significant variations in operating conditions and cause control problems.
- Environmental factors associated with processing wood include noise, solid waste disposal, air emissions, water pollution, and facility aesthetics.
- Actions must consider land-use limitations and resource needs for relatively scaled heat/power facilities. The ability to cost-effectively collect, store, and transport biomass feedstock presents many challenges. A bio-based industry will require a safe and sustainable supply system. Research and development in this area is designed to overcome the engineering system barriers of collection, delivery, and storage of agricultural residues (U.S. DOE, Office of Energy Efficiency and Renewable Energy). Because collecting and transporting bulk biomass is costly, intermediate processing to compress bulk may be necessary. Alternatively, small-scale power generation near supply sources may be desirable.
- Among the plant growth factors that pose barriers to yield increase, soil moisture is the most limiting factor. Thus, continued selection for stress tolerance, including tolerance to moisture deficits, will be critical to achieving a crop's potential yield.
- Additional analyses would be required to discern the potential impacts that larger-scale forest residue and crop residue collection and production of perennial crops could have on traditional markets for agricultural and forest products.
- Combined heat and power offers more efficient uses of energy. (Any incentives should be MMBtu-based.)

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

AFW-5. Forestry Management Programs To Enhance GHG Benefits

Policy Description

Forests—public, private, urban, managed, and wild—provide many GHG benefits. The following actions are recommended:

- Protect and enhance the carbon stored in tree biomass by maintaining and improving the health, longevity, and number of trees in urban and residential areas. Emission reductions from reduced heating and cooling as a result of planting shade trees are a significant co-benefit.
- Promote forest cover and associated carbon stocks by establishing forests on former forestland. Additional benefits include public recreation, water quality, wildlife habitat, and enhanced biodiversity. Implement such practices as soil preparation, erosion control, and stand stocking to ensure conditions that support forest growth.
- Encourage activities that promote forest productivity and increase the amount of carbon sequestered in forest biomass and soils and in long-lived wood products. Practices may include adjusting rotation ages to increase carbon sequestration, increasing the stocking of poorly stocked lands, managing thinning and density, and increasing the acreage of short-rotation woody crops (for fiber and energy) on agricultural lands previously converted from forestland.
- Reduce the severity of wildfires to reduce GHG emissions by lowering the forest carbon lost during a fire and by maintaining carbon sequestration potential. Similarly, reducing damage from insects, disease, and invasive plants decreases GHG emissions by maintaining the carbon sequestration potential of healthy forests.

Policy Design

Goals:

Forestation—Increase permanent forestland in the state by 1 million acres by planting trees on converted forestland.

Urban Forestry—Increase the canopy cover of urban forest in Minnesota communities by 25%.

Wildfire Fuel Reduction—Conduct fuel reduction on all forest areas requiring these treatments. Direct the biomass to the most beneficial use. Primary benefits are displacement of fossil fuel and reduced combustion of live forest stands. **This is a nonquantified goal.**

Forest Health and Carbon Sequestration—Develop scientific information for incorporating carbon sequestration into forest management plans. Evaluate the impacts of increased forest harvest on GHG emissions and sequestration. Increase the proportion of harvested wood going into durable wood products. Establish a monitoring program to document the long-term impacts of climate change on Minnesota forests. **This is a nonquantified goal.**

Increase Stocking of Understocked Lands—Identify understocked forestlands administered by the state and counties in Minnesota, and optimally stock identified lands where appropriate.

Timing:

Forestation—Identify lands appropriate for reestablishing forest by 2008. Restore/establish 250,000 acres by 2015. Achieve the full goal of 1 million acres by 2025.

Urban Forestry—Increase the canopy cover of urban forest in Minnesota communities by 25% by 2025.

Wildfire Reduction—Identify and prioritize areas where wildfire fuel reduction would substantially reduce the risk of stand-replacing fires. Conduct fuel reduction on 50% of identified areas by 2015 and 100% by 2025. Direct biomass to the most beneficial uses, including biomass fuel production, where appropriate.

Forest Health and Carbon Sequestration—Examine the carbon sequestration effects of shifting to desired future forest conditions using carbon-friendly management methods. Develop scientific information on forest management options and harvest methods to increase the amount of carbon sequestered in forests. Incorporate this information into forest management plans for all publicly administered forests by 2015. Identify and increase incentives for the durable wood product industry by 2010. Establish a monitoring program to document the long-term impacts of climate change on Minnesota forests by 2010.

Increase Stocking of Understocked Lands—Identify understocked stands on state and county lands by 2010. Where appropriate, optimally stock 25% of identified stands by 2015, and all such stands by 2025.

Parties Involved: Minnesota DNR, USDA Forest Service, county land departments, local units of government (with urban and community forestry plans), MFRC, forest products industry, utilities, Minnesota Forestry Association, Tree Trust, Minnesota Shade Tree Advisory Committee, University of Minnesota, conservation and environmental interests.

Implementation Mechanisms

Develop a scientific foundation of carbon sequestration practices in Minnesota forests, including stocking, rotations (lengthened and shortened rotation), harvest methods, and tree species. Evaluate the CO_2 impacts of fire management and fire-fighting activities. Evaluate the GHG impacts of increasing annual timber harvest and production of wood fiber products and other forest values. Analyze the GHG impacts of different end uses of Minnesota timber harvest (e.g., engineered products, pulp and paper, energy, solid wood products).

Evaluate and provide incentives, such as tax benefits or government purchasing programs, to support investments into wood products that store carbon for long periods of time.

Increase the number of communities implementing inventory-based forest management plans from 50 to 150 by 2025.

Related Policies/Programs in Place

The Minnesota DNR's Division of Forestry has numerous programs. The Forest Management Section administers programs pertaining to timber management and forest regeneration on state lands, forest pest management on public and private lands, inventory data (including aerial surveys of forested counties), timber harvest, and the forest products industry. The Forest Stewardship Program and Urban and Community Forest Program provide assistance to landowners and communities.

FSC and the Sustainable Forestry Initiative operate certification programs that promote and verify sustainable forestry practices and provide consumers with an opportunity to purchase wood products that are certified to meet sustainability standards.

The 2007 Minnesota legislature has directed BSWR to administer $500,000 in grants to conduct site-level ecological research and assessments, a clean energy program, and technical teams for native seed-harvesting and working-lands initiatives.

The state has spent millions of dollars since 1990 on a nationally recognized program called Minnesota ReLeaf. This cost-share program is designed to plant trees in urban and rural areas to sequester carbon, promote energy conservation, and provide an array of other co-benefits.

The Minnesota Terrestrial Carbon Sequestration Initiative is a scientific-policy research and stakeholder forum investigating biological sequestration options pertaining to the state's diverse ecosystems.

Type(s) of GHG Reductions

CO_2: Promotion of forestry management programs serves to increase the sequestration of carbon in forested lands, as well as prevent carbon currently stored in Minnesota's forests from being released.

Estimated GHG Reductions and Net Costs or Cost Savings

Discussion and quantification of GHG benefits and economic costs for AFW-5 are presented in five parts:

A. Forestation

B. Urban forestry

C. Wildfire fuel treatments (not quantified)

D. Restocking of understocked land

E. Forest health and enhanced carbon sequestration (not quantified)

A. Forestation

GHG Reduction Potential in 2015, 2025 ($MMtCO_2e$): 0.55, 2.19, respectively.

Net Cost per tCO_2e Reduced: $13.

Data Sources:

- Forest carbon stocks from Northern Lake States tables in James E. Smith, Linda S. Heath, Kenneth E. Skog, and Richard A. Birdsey. *Methods for Calculating Forest Ecosystem and Harvested Carbon With Standard Estimates for Forest Types of the United States*, General Technical Report NE-343, Newtown, PA: U.S. Department of Agriculture, U.S. Forest Service, Northeastern Research Station, 2006. Available at: http://www.treesearch.fs.fed.us/pubs/22954. (Also published as part of the DOE Voluntary GHG Reporting Program.)
- Data on distribution of forest types in Minnesota from USFS, Forest Inventory & Analysis Program, Forest Inventory Analysis 2005 data, available at: http://www.ncrs2.fs.fed.us/4801/fiadb/fim21/wcfim21.asp
- Cost of tree planting in southern Minnesota from the Mankato DNR, Forestry Office, "Planting Trees in Southern Minnesota," available at: http://www.dnr.state.mn.us/areas/forestry/mankato/pl_tree_smn.html

Quantification Methods:

A weighted-average annual rate of carbon sequestration for young-aged forests in Minnesota was calculated as 0.6 tons of carbon (C)/acre/year using data on forest types in Minnesota and corresponding carbon stocks by age class published by the USFS (Table I-17). For each forest type group for which carbon stock data are available, annual carbon sequestration rates were calculated by subtracting carbon stocks in new stands (0 years) from carbon stocks in 15-year-old stands and dividing by 15 years. An average rate was calculated, weighted by area of each forest type to take into account variation in carbon sequestration across forest types. A 15-year rate was used to reflect the average age of forested stands during the timeframe of analysis. Young stands typically sequester carbon at faster rates than older stands.

Table I-17. Data on carbon stocks, 15-year annual average sequestration rates, and forest area by forest type, used to calculate a weighted-average annual sequestration rate for forestation

Forest Type	Carbon Stocks at Age 0 years (tC/acre)	Carbon Stocks at Age 15 years (tC/acre)	Average Annual Sequestration* (tC/acre/year)	Area (acres)
Aspen-Birch				
Soils	43.3	43.3		
Biomass	0.8	9.1	0.55	6,729,732
Elm-Ash-Cottonwood				
Soils	54.6	54.6		
Biomass	0.8	10	0.61	1,326,611
Maple-Beech-Birch				
Soils	40.8	40.8		
Biomass	0.9	11.5	0.71	1,820,390
Oak-Hickory				
Soils	29.5	29.5		
Biomass	0.8	9.9	0.61	1,162,369
Spruce-Balsam Fir				
Soils	79.5	79.5		
Biomass	0.9	10.7	0.65	3,702,731

Forest Type	Carbon Stocks at Age 0 years (tC/acre)	Carbon Stocks at Age 15 years (tC/acre)	Average Annual Sequestration* (tC/acre/year)	Area (acres)
White-Red-Jack Pine				
Soils	36.7	36.7		
Biomass	0.8	7.5	0.45	984,280
Weighted Average			**0.60**	

tC/acre = metric tons of carbon per acre.

*Published soil carbon stocks do not vary with stand age. Carbon sequestration rates are based on changes in biomass carbon stocks over time (i.e., live trees, standing dead wood, understory, down dead wood, and litter/debris on the forest floor).

The estimated annual acres of land to be forested were derived from the policy goals. To achieve the goal of foresting 250,000 acres by 2015, forests would need to be planted on 31,250 acres each year from 2008 to 2015. From 2015 to 2025, 75,000 acres per year would need to be forested to achieve a total of 1 million acres forested by 2025. Because a forest continues to accumulate carbon each year after it is planted, the weighted-average annual carbon sequestration rate was multiplied by the cumulative acres of forested land each year (which includes forests planted that year and those planted in prior years since 2008). Forested acres (annual and cumulative) and annual total carbon sequestration are shown in Table I-18. Reductions are calculated in tons of carbon and are converted to standard units of MMtCO$_2$e.

Table I-18. Calculation of annual carbon sequestration from and costs to implement forestation from 2008 to 2025

Year	Acres	Cumulative Acres	Carbon Sequestration (tC/year)	Carbon Sequestration (MMtCO$_2$e/year)	Cost	Discounted Cost
2008	31,250	31,250	18,655	0.07	$10,937,500	$10,937,500
2009	31,250	62,500	37,310	0.14	$10,937,500	$10,416,667
2010	31,250	93,750	55,965	0.21	$10,937,500	$9,920,635
2011	31,250	125,000	74,619	0.27	$10,937,500	$9,448,224
2012	31,250	156,250	93,274	0.34	$10,937,500	$8,998,308
2013	31,250	187,500	111,929	0.41	$10,937,500	$8,569,817
2014	31,250	218,750	130,584	0.48	$10,937,500	$8,161,731
2015	31,250	250,000	149,239	0.55	$10,937,500	$7,773,077
2016	75,000	325,000	194,010	0.71	$26,250,000	$17,767,033
2017	75,000	400,000	238,782	0.88	$26,250,000	$16,920,984
2018	75,000	475,000	283,554	1.04	$26,250,000	$16,115,223
2019	75,000	550,000	328,325	1.20	$26,250,000	$15,347,831
2020	75,000	625,000	373,097	1.37	$26,250,000	$14,616,982
2021	75,000	700,000	417,869	1.53	$26,250,000	$13,920,935
2022	75,000	775,000	462,640	1.70	$26,250,000	$13,258,034
2023	75,000	850,000	507,412	1.86	$26,250,000	$12,626,699
2024	75,000	925,000	552,183	2.02	$26,250,000	$12,025,427
2025	75,000	1,000,000	596,955	2.19	$26,250,000	$11,452,788
Total	**1,000,000**		**4,626,401**	**17**	**$350,000,000**	**$218,277,896**

tC = tons of carbon; MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

The cost of forestation was estimated based on average costs for tree planting in southern Minnesota.[79] The Minnesota DNR reports an average cost of \$350–\$400 per acre to plant trees in existing agricultural fields, including the cost of planting stock, herbicide treatments, equipment rental, labor, and upkeep for the first two years. In reality, costs will vary, depending on the specific goals of the tree-planting project, species planted, and site conditions. The value of \$350 was used for this analysis. Potential future cost savings from forest products (e.g., merchantable timber or bioenergy feedstocks) are not taken into account, because they would most likely not be realized during the timeframe of this analysis.

Annual costs were calculated by multiplying the number of acres planted each year by \$350/acre (Table I-16). Annual costs were discounted using a 5% rate to convert future dollars to present values. The sum of annual 2008–2025 discounted costs yields a \$218 million estimate of the net present value (NPV) of this policy. The cost-effectiveness is calculated by dividing the NPV by the cumulative GHG benefit of 16.98 MMtCO$_2$e over the same time frame, yielding a cost-effectiveness of \$12.87 per ton of CO$_2$e saved.

B. Urban Forestry

GHG Reduction Potential in 2015, 2025 (MMtCO$_2$e): 1.2, 2.7, respectively.

Net Cost per tCO$_2$e Reduced: –\$12 (cost saving)

Data Sources:

- Information about current numbers of trees in urban forests and annual C storage in urban trees in Minnesota is from Nowak et al., USDA Forest Service, Northern Research Station, Urban Forest Effects on Environmental Quality State Summary data for Minnesota, available at: http://www.fs.fed.us/ne/syracuse/Data/State/data_MN.htm
- Information about fossil fuel reductions through reduced demand for cooling and protection from wind is from McPherson and Simpson (1999), *Carbon Dioxide Reduction Through Urban Forestry*, USFS PSW-GTR-171. E. Gregory McPherson and James R. Simpson, *Carbon Dioxide Reduction Through Urban Forestry: Guidelines for Professional and Volunteer Tree Planters*, Gen. Tech. Rep. PSW-GTR-171, Washington, DC: U.S. Department of Agriculture, U.S. Forest Service, 1999. Available at: http://www.treesearch.fs.fed.us/pubs/6779
- Data on the costs of tree planting and maintenance are from E. Gregory McPherson, James R. Simpson, Paula J. Peper, Scott E. Maco, Shelley L. Gardner, Shauna K. Cozad, and Qingfu Xiao, *Midwest Community Tree Guide: Benefits, Costs and Strategic Planting*, Gen. Tech. Rep. PSW-199, Washington, DC: U.S. Department of Agriculture, U.S. Forest Service, 2006. Available at: http://www.treesearch.fs.fed.us/pubs/25927

Quantification Methods:

(A) Carbon Sequestration in Urban Trees
Minnesota currently has an estimated 127,767,000 urban trees. A 25% increase in tree cover would require planting approximately 25% more, or a total of 31,941,750 trees. To achieve an

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[79] Mankato DNR, Forestry Office, “Planting Trees in Southern Minnesota,” available at: http://www.dnr.state.mn.us/areas/forestry/mankato/pl_tree_smn.html

increase in urban tree cover of this many trees in Minnesota by 2025, approximately 1,774,542 trees per year would need to be planted in Minnesota communities beginning in 2008 (assuming this rate stays constant up to 2025). Annual carbon sequestration per urban tree is calculated as 0.006 tC/tree/year, based on statewide average data reported by the USDA Forest Service. This is the average annual per-tree carbon sequestration value when the total estimated annual carbon sequestration in Minnesota urban trees (760,000 tC/year) is divided by the total number of urban trees. Because trees continue to accumulate carbon each year after being planted, the average annual carbon sequestration rate was multiplied by the cumulative number of trees planted each year (which includes trees planted that year and those planted in prior years since 2008). Table I-19 shows the number of trees planted (annual and cumulative) and annual total carbon sequestration. Reductions are calculated in tons of carbon and converted to standard units of MMtCO$_2$e.

Table I-19. Summary of GHG benefits from urban tree planting

Year	Number of Trees Planted This Year	Cumulative Number of Trees Planted	C Sequestered (tC/year)	C Sequestered (MMtCO$_2$e/year)	C Savings From Shading Effects (MMtCO$_2$e/year)	Total Carbon Savings (MMtCO$_2$e/year)
2008	1,774,542	1,774,542	10,556	0.04	0.11	0.15
2009	1,774,542	3,549,083	21,111	0.08	0.22	0.30
2010	1,774,542	5,323,625	31,667	0.12	0.33	0.45
2011	1,774,542	7,098,167	42,222	0.15	0.44	0.60
2012	1,774,542	8,872,708	52,778	0.19	0.56	0.75
2013	1,774,542	10,647,250	63,333	0.23	0.67	0.90
2014	1,774,542	12,421,792	73,889	0.27	0.78	1.05
2015	1,774,542	14,196,333	84,444	0.31	0.89	1.20
2016	1,774,542	15,970,875	95,000	0.35	1.00	1.35
2017	1,774,542	17,745,417	105,556	0.39	1.11	1.50
2018	1,774,542	19,519,958	116,111	0.43	1.22	1.65
2019	1,774,542	21,294,500	126,667	0.46	1.33	1.80
2020	1,774,542	23,069,042	137,222	0.50	1.44	1.95
2021	1,774,542	24,843,583	147,778	0.54	1.55	2.10
2022	1,774,542	26,618,125	158,333	0.58	1.67	2.25
2023	1,774,542	28,392,667	168,889	0.62	1.78	2.40
2024	1,774,542	30,167,208	179,444	0.66	1.89	2.55
2025	1,774,542	31,941,750	190,000	0.70	2.00	2.70
Total			**1,805,000**	**6.6**	**19.0**	**25.6**

C = carbon; tC = tons of carbon; MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

(B) Avoided Fossil Fuel Emissions

GHG reductions from avoided fossil fuel use for heating and cooling can occur as a result of planting trees that provide additional shade and wind protection to buildings. The total benefits are a function of three different types of impacts: reduced cooling demand, reduced demand for heating due to wind reduction, and increased demand for heating due to wintertime shading. An average annual per-tree GHG reduction factor of 0.13 tons CO$_2$e/tree/year was calculated from data in McPherson et al. (Table I-20).[80] The estimate assumes that the trees planted are split among residential settings with pre-1950, 1950–1980, and post-1980 homes using the default distribution provided by McPherson et al. of 45%, 42%, and 13%, respectively.

Table I-20. Net GHG emission reductions from shade trees planted in the Northern Tier Climate Region

Vintage	Default Vintage Distribution (%)	Cooling (tCO_2 saved per tree)	Heating (tCO_2 emitted per tree)	Wind (tCO_2 saved per tree)	Net Effect
Pre-1950	0.45	0.122	–0.0227	0.1006	0.1999
1950–1980	0.42	0.0079	–0.0141	0.0658	0.0596
Post-1980	0.13	0.0089	–0.0198	0.0889	0.078
Weighted Average (tCO_2e)					**0.125**

tCO_2 = tons of carbon dioxide; tCO_2e = tons of carbon dioxide equivalent.

To calculate total avoided GHG emissions due to increased shading, it was assumed that 50% of the new urban trees are planted where they can have shading effects. Table I-20 describes the average GHG impact per tree of planting urban trees in the Northern Tier climate region. These values assume medium-sized evergreen trees are planted, and assume average tree distribution around buildings (i.e., these fossil fuel reduction factors are average for existing buildings, and do not necessarily assume that trees are optimally placed around buildings to maximize energy efficiency). These factors are also dependent on the fuel mix (coal, hydroelectric, nuclear, etc.) in the regions of interest, and are thus likely to change if the electricity mix changes from its 1999 distribution.

The shading benefits occur in the year a tree is planted and every year thereafter. Thus, the GHG emission reduction factor is multiplied by the cumulative number of trees planted each year to estimate annual avoided fossil fuel emissions (Table I-20). Values are converted to standard units of $MMtCO_2e$. The avoided emissions and carbon sequestration benefits are summed in Table I-20 to show the total net benefits of urban tree planting.

(C) Cost Analysis

Data are available on the costs and cost savings of urban tree planting in the Midwest.[81] The economic costs of take into account the costs of planting and annual maintenance, including the costs of program administration and waste disposal. The economic benefits of tree planting include the cost avoided from reduced energy use. Data are also available on the estimated economic benefits of such services as provision of clean air, hydrologic benefits (e.g., stormwater control), and aesthetic enhancement. However, these indirect co-benefits are not

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[80] E.G. McPherson and J.R. Simpson, *Carbon Dioxide Reduction Through Urban Forestry*: *Guidelines for Professional and Volunteer Tree Planters*, Gen. Tech. Rep. PSW-GTR-171, Washington, DC: U.S. Department of Agriculture, U.S. Forest Service, 1999. Available at: http://www.treesearch.fs.fed.us/pubs/6779

[81] E.G. McPherson, J.R. Simpson, P.J. Peper, S.E. Maco, S.L. Gardner, et al., *Midwest Community Tree Guide: Benefits, Costs and Strategic Planting*, Gen. Tech. Rep. PSW-199, Washington, DC: U.S. Department of Agriculture, U.S. Forest Service, 2006. Available at: http://www.treesearch.fs.fed.us/pubs/25927

explicitly quantified in the analysis to be consistent with standard analysis of the MCCAG Technical Work Group policies.

Costs and cost savings were estimated from average annual costs and cost savings over 40 years for a range of tree sizes, published by public and private parties. The cost estimate used in this analysis, $26.38 per tree, was calculated as the average of small, medium, and large trees under public and private management. A cost savings of –$28.03 per tree per year was also calculated as the average of small, medium, and large trees under public and private management. The average cost and cost savings values yield a net cost savings of –$1.65 per tree (costs minus cost savings). Table I-21 shows estimated economic costs and cost savings for all categories.

Table I-21. Cost data for public and private entities in the Midwest planting small, medium, and large trees (40-year annual averages)

Tree Size	Private ($/tree)	Public ($/tree)	Average of Public and Private ($/tree)
Small (Crabapple)			
Cost savings (energy saved)	15.60	18.64	17.12
Costs*	17.02	26.87	21.95
Medium (Red Oak)			
Cost savings (energy saved)	20.31	25.62	22.97
Costs*	20.66	33.61	27.14
Large (Hackberry)			
Cost savings (energy saved)	44.05	43.93	43.99
Costs*	23.10	36.99	30.05
Average Across Small, Medium, Large Trees ($ per tree)			
Cost savings (energy saved)			28.03
Costs*			26.38
Net Costs			**(1.65)**

*Includes trees planting, pruning, removal, and disposal; pests and disease; infrastructure repair; irrigation; cleanup; liability and legal; and administration and other costs.

The cost savings is estimated using 40-year averages; thus, it represents lifetime costs applicable in the year planted and every year thereafter during the time frame of this analysis (e.g., planting costs $80 per tree in the year the tree is planted; however the 40-year average cost is $10 per tree). To estimate total cost savings, –$1.65 per tree was multiplied by the cumulative number of trees planted each year (Table I-22). This corresponds to a cumulative 2008–2020 cost savings (or NPV) of –$295 million, with an estimated cost-effectiveness of –$11.52/tCO$_2$e.

Table I-22. Summary of cost savings from urban tree planting

Year	Cumulative Number of Trees in Program	Total Carbon Savings (MMtCO$_2$e/year)	Net Costs	Discounted Costs
2008	1,774,542	0.15	–$2,927,994	–$2,927,994
2009	3,549,083	0.30	–$5,855,988	–$5,577,131
2010	5,323,625	0.45	–$8,783,981	–$7,967,330

Year	Cumulative Number of Trees in Program	Total Carbon Savings ($MMtCO_2e$/year)	Net Costs	Discounted Costs
2011	7,098,167	0.60	–$11,711,975	–$10,117,244
2012	8,872,708	0.75	–$14,639,969	–$12,044,339
2013	10,647,250	0.90	–$17,567,963	–$13,764,958
2014	12,421,792	1.05	–$20,495,956	–$15,294,398
2015	14,196,333	1.20	–$23,423,950	–$16,646,964
2016	15,970,875	1.35	–$26,351,944	–$17,836,033
2017	17,745,417	1.50	–$29,279,938	–$18,874,109
2018	19,519,958	1.65	–$32,207,931	–$19,772,876
2019	21,294,500	1.80	–$35,135,925	–$20,543,248
2020	23,069,042	1.95	–$38,063,919	–$21,195,414
2021	24,843,583	2.10	–$40,991,913	–$21,738,886
2022	26,618,125	2.25	–$43,919,906	–$22,182,537
2023	28,392,667	2.40	–$46,847,900	–$22,534,641
2024	30,167,208	2.55	–$49,775,894	–$22,802,910
2025	31,941,750	2.70	–$52,703,888	–$22,994,532
Total		**25.6**		**–$294,815,543**

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

C. Wildfire Fuel Treatment (not quantified)

Forest fire mitigation involves reducing the amount of fuel (i.e., live and dead biomass) in the forest to decrease the risk of future wildfires. Forest fire mitigation can affect GHG emissions and carbon sequestration in several ways. Forest biomass can be physically removed, or it can be combusted using controlled prescribed fires. When biomass is mechanically removed, it can be used in ways that keep the carbon stored in biomass and/or displace the use of fossil fuels (i.e., biomass is combusted off site for energy capture or used to produce biofuels). If carbon is combusted in a wildfire, the potential bioenergy benefits are lost, as well as the opportunity to produce durable wood products.

In addition, studies show that pre-commercial thinning treatments result in an increased rate of growth among remaining trees as a result of reducing intertree competition, leading to faster carbon sequestration rates in forests that are treated regularly. This trend may also apply to thinning treatments to reduce fire risk, and could lead to small net gains in forest carbon stocks over time. Due to limited data on the extent of increased growth after fire-thinning treatment, this GHG benefit was not assessed quantitatively.

Fire mitigation will also reduce future incidences of extreme wildfires. However, the extent to which fires are avoided and the impacts of avoided fires on forest carbon stocks are difficult to assess. Fuel-thinning treatments can reasonably be assumed to reduce wildfire emissions in the near term. However, because forests are capable of regenerating back to initial carbon densities, over the long term wildfires may not result in net CO_2 emissions or a net loss of forest carbon stocks (i.e., CO_2 emissions from fires are eventually offset by future carbon sequestration on burned sites).[82] There are exceptions, such as when fires permanently alter the characteristics of a forest, replacing the original forest with an ecosystem of lower carbon density (e.g., dense forest converted to open grassland or woodland). Uncharacteristically high fuel loads within the forest can create conditions for this type of high-intensity, ecosystem-altering fire. These conditions have occurred to an increasing extent in Minnesota in recent years. One example is the 1999 blowdown that resulted in 300,000+ acres in the Boundary Waters Canoe Area Wilderness (BWCAW) and surrounding areas being affected, with 10%–100% of the standing trees blown down. A 2006 wildfire that began in the blowdown in the vicinity of Ham Lake in the BWCAW burned 36,000 acres (mostly within the BWCAW).

These complexities have challenged the development of a methodological framework to analyze the potential GHG benefits of forest health programs. Advances have been made by researchers at the University of Washington, who developed a life-cycle GHG assessment of long-term impacts of fuel-thinning treatments, taking into account carbon in the forest and wood products, and displaced emissions from bioenergy and wood product substitution.[83] Their study finds that when a "no action" baseline is compared with different potential fuel treatment strategies, (1) all treatment scenarios result in more total carbon stored and GHG reductions when the carbon in wood products and avoided emissions from bioenergy and wood product substitution are taken into account; and (2) all treatment scenarios remove more carbon from the forest than wildfires would have, resulting in lower mean carbon in the forest relative to the baseline during the early periods for all treatments and over the long term for most treatments (there are a few treatments with small positive carbon gains after 2020). The study concludes that the measurable carbon benefits of avoided wildfires are found in maintaining the ability of forests to produce wood products and bioenergy, and the net benefits are on the order of a 30% increase in carbon storage and GHG reductions relative to taking no action.

Due to the methodological challenges noted above, the specific potential GHG benefits have not been quantified. Some of the GHG benefits estimated for AFW-4 could be attributable to this policy, assuming the feedstocks are supplied by the forest-thinning treatments envisioned here.

D. Restocking Understocked Land

GHG Reduction Potential in 2015, 2025 (MMtCO$_2$e): 2.1, 8.4, respectively.

Net Cost per tCO$_2$e Reduced: $33.

Data Sources:

- Forest carbon stocks from Northern Lake States tables in James E. Smith, Linda S. Heath, Kenneth E. Skog, and Richard A. Birdsey. *Methods for Calculating Forest Ecosystem and*

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[82] D.M. Kashian, W.H. Romme, D.B. Tinker, M.G. Turner, and M.G. Ryan (2006), "Carbon Storage on Landscapes With Stand-Replacing Fires," *BioScience* 56(7):598–606, 2006. Available at: http://www.bioone.org/perlserv/?request=get-abstract&doi=10.1641%2F0006-3568(2006)56%5B598%3ACSOLWS%5D2.0.CO%3B2.

[83] B. Lippke, J. Comnick, and L. Mason, "Alternative Landscape Fuel removal Scenarios: Impacts of Treatment Thinning Intensity and Implementation Schedules on Fire Hazard Reduction Effectiveness, Carbon Storage, and Economics," RTI/CORRIM Joint Working Paper No. 6, RTI/CORRIM Joint Working Paper No. 6, Seattle, WA: University of Washington, Rural Technology Initiative and Consortium for Research on Renewable Industrial Materials, June 2006. Available at: http://www.ruraltech.org/pubs/working/

Harvested Carbon With Standard Estimates for Forest Types of the United States, General Technical Report NE-343, Newtown, PA: U.S. Department of Agriculture, U.S. Forest Service, Northeastern Research Station, 2006. Available at: http://www.treesearch.fs.fed.us/pubs/22954. (Also published as part of the DOE Voluntary GHG Reporting Program.)

- Data on distribution of forest types in Minnesota from USFS, Forest Inventory & Analysis Program, Forest Inventory Analysis 2005 data, available at: http://www.ncrs2.fs.fed.us/4801/fiadb/fim21/wcfim21.asp
- Cost of tree planting in southern Minnesota from the Mankato DNR, Forestry Office, “Planting Trees in Southern Minnesota,” available at: http://www.dnr.state.mn.us/areas/forestry/mankato/pl_tree_smn.html

Quantification Methods:

Statewide, Minnesota contains roughly 16.3 million acres of forestland. Of this, roughly 2.6% is classified as non-stocked, 17.3% is classified as poorly stocked, and 33.9% is classified as moderately stocked. The remainder is either fully stocked (36.3%) or overstocked (10%) (Table I-23.[84]

Table I-23. Forest acreage by stocking class in Minnesota

Stocking Class	Acreage	Percent of Total
Overstocked	1,622,546	10.0%
Fully stocked	5,910,973	36.3%
Moderately stocked	5,526,541	33.9%
Poorly stocked	2,814,274	17.3%
Non-stocked	426,308	2.6%
Total (acres)	**16,300,643**	

In some cases, a harvest/replant strategy is considered the most appropriate and cost-effective solution for restocking understocked land.[85] This strategy can result in large one-time losses due to forest harvest. Because the annual sequestration in replanted forest is so much lower than the one-time surge in emissions due to harvest, it can take many years to reach a break-even point in overall carbon storage when the harvest/replant strategy is implemented.

For this analysis, it was assumed that restocking would be an incremental increase in carbon sequestration on existing stands. In other words, no harvest would accompany the restocking activity, such that the carbon sequestration benefit is a function only of carbon storage by the additional trees planted in an understocked forest.

Stocking is defined by USFS FIA Program as “the degree of occupancy of land by trees, measured by basal area and/or number of trees in a stand compared with the basal area and/or

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[84] USFS/Minnesota DNR cooperative Forest Inventory and Analysis (FIA), 2006. Data available from: http://www.fia.fs.fed.us/

[85] B. Sohngen et al., “The Nature Conservancy Conservation Partnership Agreement Part 4: Opportunities for Improving Carbon Storage and Management on Forest Lands,” 2007. See http://conserveonline.org/workspaces/necarbonproject/The%20Report/Part_4_Forest_Management/view

number of trees required to fully use the growth potential of the land (or the stocking standard)."[86] Following this definition, the percentage reduction in occupancy per acre of understocked land as compared with an acre of fully stocked land was quantified by stocking class (Table I-24).

Table I-24. Stocking levels as defined by FIA in terms of percentage occupancy compared against a fully stocked standard.

Stocking Class	Minimum Percentage of Full Stocking Standard	Maximum Percentage of Full Stocking Standard	Midpoint Percentage of Full Stocking Standard	% Reduction on Poorly Stocked Forests Relative to Fully Stocked Forests
Non-stocked	0	9	4.5	95.5
Poorly stocked	10	59	34.5	65.5
Moderately stocked	60	99	79.5	20.5
Fully stocked	100	129	114.5	not applicable
Overstocked	130	160	145	not applicable

An average of carbon sequestration per acre of understocked forest in each forest type and stocking class was then calculated, assuming reductions in carbon sequestration occur proportionally to reductions in degree of occupancy (Table I-25). Average statewide carbon sequestration values taken from Section A, Forestation, were assumed to reflect fully stocked stands.

Table I-25. Carbon sequestration rates in understocked stands (tC/acre/year)

Forest Type	Non-Stocked	Poorly Stocked	Moderately Stocked
Aspen-Birch	0.0263	0.2019	0.4653
Elm-Ash-Cottonwood	0.0246	0.1886	0.4346
Maple-Beech-Birch	0.0354	0.2714	0.6254
Oak-Hickory	0.0332	0.2548	0.5872
Spruce-Balsam Fir	0.0326	0.2502	0.5766
White-Red-Jack Pine	0.0437	0.3350	0.7719

A weighted average of incremental carbon sequestration rates resulting from restocking of understocked forest in all stocking classes and forest types was calculated (Table I-26).

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[86] USDA USFS, Forest Inventory & Analysis Program, "Northeastern Forestry Inventory and Analysis." See http://www.fs.fed.us/ne/fia/methodology/def_qz.htm

Table I-26. Incremental carbon sequestration (tC/acre/year) resulting from increased stocking of understocked forests

	Incremental C Sequestration From Restocking (tC/acre/year)			Acres Available for Restocking		
Forest Type	**Moderately Stocked**	**Poorly Stocked**	**Non-Stocked**	**Moderately Stocked**	**Poorly Stocked**	**Non-Stocked**
Aspen-Birch	0.1200	0.3834	0.5590	2,132,119	822,808	26,707
Elm-Ash-Cottonwood	0.1121	0.3581	0.5221	481,806	326,895	60,135
Maple-Beech-Birch	0.1613	0.5153	0.7513	659,234	283,827	21,318
Oak-Hickory	0.1514	0.4838	0.7054	430,040	353,313	35,155
Spruce-Balsam Fir	0.1487	0.4751	0.6927	1,342,644	797,059	16,492
White- Red- Jack Pine	0.1990	0.6359	0.9272	366,409	158,592	8,218
Weighted Average	**0.139**	**0.448**	**0.632**	not applicable	not applicable	not applicable

tC = tons of carbon.

The goals for this policy specify that 25% of the understocked acreage will be restocked by 2015, with the remaining 75% of understocked acreage restocked between 2016 and 2025. For this analysis, it was assumed that the acreage targets in each of the two time periods (2008–2015 and 2016–2025) would be implemented gradually and linearly, achieving full policy implementation by 2025. It was assumed further that non-stocked, poorly stocked, and moderately stocked acreage would be equally likely to be restocked during each year of policy implementation. Acreage targets for each stocking class by time period are given in Table I-27.

Table I-27. Acreage targets for restocking non-stocked, poorly stocked, and moderately stocked land for 2008–2015 and 2016–2025

Stocking Class	Total Acreage Restocked by 2015	Total Acreage Restocked by 2025	Annual Acreage Restocked, 2008–2015	Annual Acreage Restocked, 2016–2025
Non-stocked	106,577	426,308	13,322	3,1973
Poorly stocked	703,569	2,814,274	87,946	21,1071
Moderately stocked	1,381,635	5,526,541	172,704	41,4491

The cost of restocking was assumed to be similar to average costs for tree planting in southern Minnesota.[87] Minnesota DNR reports an average cost of $350–$400 per acre to plant trees in existing agricultural fields, including the cost of planting stock, herbicide treatments, equipment rental, labor, and upkeep for the first two years. In reality, costs will vary, depending on the specific goals of the tree-planting project, species planted, and site conditions. The upper limit of $400 was used for this analysis, since interplanting among existing forest is likely to be more time consuming and labor intensive than planting on open land.

Annual costs were calculated by multiplying the number of acres restocked each year by $400/acre (Table I-28). Annual costs were discounted using a 5% rate to convert future dollars to present values. The sum of annual 2008–2025 discounted costs yields a $2.2 trillion estimate of the NPV of this policy. The cost-effectiveness is calculated by dividing the NPV by the

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[87] Mankato DNR, Forestry Office, "Planting Trees in Southern Minnesota." See http://www.dnr.state.mn.us/areas/forestry/mankato/pl_tree_smn.html

cumulative GHG benefit of 65.37 MMtCO$_2$e over the same time frame, yielding a cost-effectiveness of $33/tCO$_2$e saved.

Table I-28. Summary of GHG benefits and economic costs of restocking understocked forestland

Year	Acres Restocked In All Stocking Classes	Incremental Benefit (tC/year)	Incremental Benefit (MMtCO$_2$e/ year)	Annual Cost	Discounted Cost
2008	273,973	71,893	0.26	$109,589,041	$109,589,041
2009	273,973	143,785	0.53	$109,589,041	$104,370,515
2010	273,973	215,678	0.79	$109,589,041	$99,400,491
2011	273,973	287,570	1.05	$109,589,041	$94,667,134
2012	273,973	359,463	1.32	$109,589,041	$90,159,175
2013	273,973	431,356	1.58	$109,589,041	$85,865,881
2014	273,973	503,248	1.85	$109,589,041	$81,777,030
2015	273,973	575,141	2.11	$109,589,041	$77,882,885
2016	657,534	747,683	2.74	$263,013,698	$178,018,024
2017	657,534	920,225	3.37	$263,013,698	$169,540,975
2018	657,534	1,092,767	4.01	$263,013,698	$161,467,595
2019	657,534	1,265,310	4.64	$263,013,698	$153,778,662
2020	657,534	1,437,852	5.27	$263,013,698	$146,455,869
2021	657,534	1,610,394	5.90	$263,013,698	$139,481,780
2022	657,534	1,782,936	6.54	$263,013,698	$132,839,790
2023	657,534	1,955,479	7.17	$263,013,698	$126,514,086
2024	657,534	2,128,021	7.80	$263,013,698	$120,489,606
2025	657,534	2,300,563	8.44	$263,013,698	$114,752,005
Cumulative Total	**8,767,123**		**65.4**		**$2,187,050,045**

tC = tons of carbon; MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

D. Forest Health and Enhanced Carbon Sequestration

While increases in forest health are usually accompanied by enhanced productivity, the extent to which enhanced productivity actually results in net carbon sequestration is highly uncertain. Appropriate silvicultural treatment can free up growing space (i.e., access to resources) for the remaining trees and usually favors healthier, genetically superior trees with faster growth rates. However, increases in productivity come at a cost, because carbon is removed from the forest through harvest. Thus increased rates of carbon uptake that result from silvicultural treatment do not, in and of themselves, translate into increased net sequestration, unless the carbon harvested to achieve the elevated productivity goes into some kind of long-term storage or is used to achieve a GHG benefit via some other means, such as electricity production.

In addition, while there is broad agreement about general principles that can be used to achieve carbon sequestration benefit through forest management,[88] scientific uncertainty remains with

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[88] R.A. Birdsey et al., "North American Forests," in The First State of the Carbon Cycle Report (SOCCR): The North American Carbon Budget and Implications for the Global Carbon Cycle, Synthesis and Assessment Product 2.2, A.W. King, et al., eds., Washington, DC: U.S. Climate Change Science Program and Subcommittee on Global Change Research, March 2007. See http://www.climatescience.gov/Library/ sap/sap2-2/public-review-draft/SOCCR_Chapter11.pdf

respect to the specific forest management strategies that can be used to achieve specific GHG benefits. Forest certification may be one mechanism for achieving enhanced carbon storage on forestland, but certification standards currently in use do not address enhanced carbon storage (or reduced carbon losses) specifically as a benefit of certification.

For these reasons, the recommendation for this policy leans toward developing the state of the science more fully for quantifying the specific mechanisms by which healthy forests in Minnesota might enhance net carbon sequestration. An important component of this policy is the development of scientific information on specific management options and harvest techniques that will increase the amount of carbon sequestered in Minnesota forests, and to implement this information into forest management plans on publicly administered forests by 2015.

Key Assumptions: See analysis, above.

Key Uncertainties

Tree mortality has doubled since 1977, from 123 to 250 million cubic feet. The mortality rate could continue to rise, increasing susceptibility to wildfires and large releases of CO_2.

Additional Benefits and Costs

Management for carbon sequestration will also benefit production of high-quality wood products for the construction industry, keeping the carbon out of the cycle for a longer period of time.

Feasibility Issues

This proposal identifies aggressive goals for increased forest acreages and stocking beginning in 2008. Land use limitations and increasing pressure to convert forestland to other uses (e.g., agriculture, housing, and commercial development) could prevent reaching reforestation goals in the time frame suggested. Insects, diseases, and invasive species of plants will limit opportunities for successful reforestation and full stocking. The MCCAG recognized that the goal of "One Million Acres of New Forest" would be difficult to achieve given these constraints.

The full costs of proposals, including ramping up the capacity of current programs to identify, administer, and implement forestry projects quickly, have not been included in calculations. Nearly half (46%) of the under-stocked acres of forestland are privately owned with the rest distributed among a variety of federal, state, and local government agencies. To be successful, proposals will need a broad coalition of government and private partners to diversify funding, implementation, and management of expanding forests on urban, rural, and public (local, state, and federal) lands.

At present, scientific understanding of forest sequestration and the technical capacity to measure and monitor changes in carbon sequestration is limited. Embarking on a major change in forest management to sequester carbon should be accompanied by research on the effects of stocking, rotations (lengthened and shortened rotations), harvest methods, and tree species and a system for monitoring results. Identification and evaluation of trade-offs with other forest management objectives, particularly those objectives that support local forest-based economies, is also necessary.

Biological sequestration is not geologically permanent. There is significant risk that carbon sequestered in forests and other ecosystems will be released by natural phenomena or human activities. There is also significant concern that environmental changes resulting from climate change, expanded pest populations, wildfire, and other causes could increase re-emission of sequestered carbon in the future.

The urban forestry goals are ambitious and in order to succeed require major bipartisan political commitment at the local, state, and federal levels in addition to major involvement by the private sector (business, NGOs, individual citizen volunteers).

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

AFW-6. Forest Protection—
Reduced Clearing and Conversion to Non-Forest Cover

Policy Description

In the mid- to late 1800s, forests covered 31 million acres in Minnesota. Over the subsequent 100-plus years, 15 million acres of this forestland were converted to other uses, mainly to farmland, but also to developed areas. Between 1990 and 2003, Minnesota forestland acreage was reduced by nearly one-half million acres, from 16.7 million acres to 16.2 million acres.[89] Because forestland captures and stores CO_2 in trees, soil, and other forest biomass at a much higher rate than developed areas and other areas without forest cover, priority should be placed on reducing conversion of forested lands to land uses with lower carbon sequestration potential.

Policy Design

Goals: Achieve "no net loss" of forestland or an increase in forest carbon stocks through local land-use planning, conservation easements, technical and financial assistance to family forest landowners, education, revised tax policy, and other appropriate mechanisms.

Timing: Stabilize current statewide forest cover acres, and achieve no net loss in carbon stocks by 2015. Decrease conversion of forestland to non-forest uses/cover. Increase carbon stocks by 2025 through reforestation and by fully stocking forestlands (see AFW-5).

Parties Involved: None identified.

Implementation Mechanisms

This policy's goals could be reached through local land-use planning, conservation easements, technical and financial assistance to family forest landowners, education, and tax incentives and disincentives. A Minnesota Forest Trust, similar to Minnesota's wetland mitigation banks, could also be created. Development projects resulting in significant losses of forest carbon stocks would be required to replace stocks or contribute to a fund for reforestation projects.

Related Policies/Programs in Place

Some counties have comprehensive land-use plans in place that encourage retention of forestland (e.g., Aitkin County), but many counties either do not have such plans or their plans do not address forestland retention. The same statement applies to municipalities. It is unlikely that any of these plans encourages no net loss of carbon stocks.

The Minnesota Forest Legacy Partnership is a group of public and private business and nonprofit interests engaged in promoting large-scale forest conservation easements in northern and central Minnesota. A more than 51,000-acre forest easement in Koochiching and Itasca counties was

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[89] Minnesota Pollution Control Agency and Center for Climate Strategies. Appendix H: Forestry, p. H-3, Table H1, "USFS Carbon Pool Data for Minnesota." June 7, 2007. See http://www.mnclimatechange.us/ewebeditpro/items/O3F12645.pdf

recently completed, and two additional easements comprising a total of 76,000 acres have been proposed in Koochiching County (located on the Ontario border in north central Minnesota). The funding for purchasing the 51,000-acre easement was obtained from private foundations and other private and state sources, and funding for the additional easements is being sought from these and federal sources. Additional forestland easements from 1,600 to over 5,000 acres have recently been completed in Itasca, Crow Wing, and Lake counties, in part with federal Forest Legacy funds. Smaller forestland easements have been completed in other counties (e.g., Rice County).

Although a number of federal and state technical and financial assistance and educational programs for family forestland owners have been in place for many years, these programs are not specifically directed at forestland or carbon stock retention. Federal funding for these programs has declined in recent years, and is highly likely to decline further in coming years.

The Sustainable Forest Incentive Act provides for reduced property taxes for private landowners who make a long-term commitment to sustainable management of their forestland. However, neither this program nor other forestland tax policy is specifically designed to retain forestland or carbon stocks.

The Minnesota Forest Resources Council has funded research by the University of Minnesota on rates of parcelization and subsequent development of forestland in Itasca County. Funds are being sought from private and public sources to extend this research across northern Minnesota; to evaluate current use and potential applicability in Minnesota of the policy tools listed above, plus other tools (e.g., land exchange, fee title ownership, regulatory programs); and to make recommendations to the legislature.

Type(s) of GHG Reductions

CO_2: Avoided emissions from forest clearing and maintenance of annual carbon sequestration from forest growth.

Estimated GHG Reductions and Net Costs or Cost Savings

GHG Reduction Potential in 2015, 2025 ($MMtCO_2e$): 2.2, 2.7, respectively.

Net Cost per tCO_2e Reduced: $3.

Data Source: James E., Linda S. Heath, Kenneth E. Skog, and Richard A. Birdsey, *Methods for Calculating Forest Ecosystem and Harvested Carbon With Standard Estimates for Forest Types of the United States*, General Technical Report NE-343, Newtown, PA: U.S. Department of Agriculture, U.S. Forest Service, Northeastern Research Station, 2006. Available at: http://www.treesearch.fs.fed.us/pubs/22954. (Also published as part of the DOE 1605(b) Voluntary GHG Reporting Program.)

Quantification Methods:

Carbon savings from this policy were estimated from two sources: (1) the amount of carbon that would be lost as a result of forest conversion to developed uses (i.e., avoided emissions), and

(2) the amount of annual carbon sequestration potential that is maintained by protecting the forest area.

1. Avoided Emissions

Carbon savings from avoided emissions were calculated using statewide average estimates of total standing forest carbon stocks in Minnesota, provided by the USFS as part of the Forest Inventory and Forecast for Minnesota.[90]

Loss of forests to development results in a large one-time surge of carbon emissions. In this case, it was assumed that 100% of the vegetation carbon stocks would be lost in the event of forest conversion to developed uses, with no appreciable carbon sequestration in soils or biomass following development. While soil carbon may be lost on forest conversion to developed use, soil carbon loss was excluded from this analysis because soil carbon dynamics are not included in the baseline calculations for the Inventory and Forecast. A comparison of data from the American Housing Survey with land-use conversion data from NRI suggests that, on average, two-thirds of the land area in residential lots is cleared during land conversion. Thus, it was assumed that, during forest conversion to developed use, 100% of the forest vegetation would be lost on 67% of the converted acreage. Using the statewide average carbon densities from the Minnesota FIA results, roughly 14.0 tons of carbon are avoided for every acre of forest preserved in Minnesota.

Between 1989 and 2003, roughly 36,927 acres of forest were lost in Minnesota annually.[91] Therefore, to reach the no-net-forest-loss target by 2015, this policy assumes that 36,927 acres must be preserved each year beginning in 2015. The number of acres targeted for policy implementation between 2008 and 2015 was calculated by dividing 36,927 by 8, and implementing the policy gradually and linearly over the 8 years between 2008 and 2015.

Each year, the number of acres estimated to remain in forestland as a result of the program was converted to units of $MMtCO_2e$ to estimate avoided emissions. Table I-29 shows the annual and total acres targeted by the program and associated avoided emissions that would be generated between 2008 and 2025.

Table I-29. Acres protected from conversion and associated avoided emissions

Year	Acres Protected From Development	Avoided Emissions From Development (tC/year)
2008	4,616	64,440
2009	9,233	128,880
2010	13,849	193,319
2011	18,466	257,759
2012	23,082	322,199
2013	27,699	386,639
2014	32,488	453,492
2015	36,927	515,449

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[90] Ibid.

[91] USDA Forest Service Forest Inventory and Analysis Unit statistics for Minnesota, at: http://www.fia.fs.fed.us

Year	Acres Protected From Development	Avoided Emissions From Development (tC/year)
2016	36,927	515,449
2017	36,927	515,449
2018	36,927	515,449
2019	36,927	515,449
2020	36,927	515,449
2021	36,927	515,449
2022	36,927	515,449
2023	36,927	515,449
2024	36,927	515,449
2025	36,927	515,449
Cumulative Totals	**535,624**	**7,476,667**

tC = metric tons of carbon.

2. Annual Sequestration Potential in Protected Forests

The calculations in this section of the analysis used default carbon sequestration values for aspen-birch and spruce-fir forest types in the Northern Lake States (USFS GTR-343, Tables A7 and A11). Average annual carbon sequestration for these forest types was calculated over 85 years for aspen-birch stands and over 125 years for spruce-fir stands, based on the maximum ages for these forest types in Minnesota.[92] The average annual sequestration rate was calculated by subtracting non-soil carbon stocks in 85- and 125-year-old stands from non-soil carbon stocks in new stands and dividing the remainder by average stand age (Table I-30). Soil carbon density was assumed constant, and is not included in the calculation.

Table I-30. Forest carbon sequestration rates

Forest Type	tC/acre (0 year)	tC/acre (85/125 years)	tC/acre/Year (average)
Aspen-Birch	10.4	48.4	0.45
Spruce-Fir	21.0	70.8	0.40

tC/acre = tons of carbon per acre.

Since 41% of Minnesota forests statewide are aspen-birch and 27% are spruce-fir,[93] this policy assumes that forests saved from development are roughly proportional to existing forests. Protected forests were assumed to be 66% aspen-birch and 34% spruce-fir.

The results for the annual sequestration potential resulting from this policy's implementation are presented in Table I-31. Forests preserved in one year continue to sequester carbon in subsequent years. Thus, annual sequestration potential includes benefits from acres preserved cumulatively under the program.

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[92] D. Zumeta, personal communication with J. Jenkins, November 2007.

[93] Minnesota Pollution Control Agency and Center for Climate Strategies, Appendix H: Forestry, p. H-3, Table H1, "USFS Carbon Pool Data for Minnesota," June 7, 2007. See http://www.mnclimatechange.us/ewebeditpro/items/O3F12645.pdf

Table I-31. Annual and cumulative carbon sequestration in forests protected from conversion between 2008 and 2020

Year	Acres Protected From Development		Cumulative Carbon Sequestration (tC/year)
	This Year	In Prior Years	For Land Protected in All Years
2008	4,616	0	1,989
2009	9,233	4,616	5,968
2010	13,849	13,849	11,937
2011	18,466	27,699	19,894
2012	23,082	46,164	29,842
2013	27,699	69,246	41,778
2014	32,488	96,945	55,779
2015	36,927	129,433	71,692
2016	36,927	166,359	87,606
2017	36,927	203,286	10,3519
2018	36,927	240,212	11,9433
2019	36,927	277,139	13,5346
2020	36,927	314,065	15,1259
2021	36,927	350,992	167,173
2022	36,927	387,918	183,086
2023	36,927	424,845	199,000
2024	36,927	461,771	214,913
2025	36,927	498,698	230,827
Cumulative Total		**535,624**	**836,043**

tC = metric tons of carbon.

3. Overall GHG Benefit of Avoided Land Conversion

The cumulative GHG benefit of avoided forestland conversion (including avoided emissions from reduced conversion, as well as annual sequestration in protected forests) was calculated in units of $MMtCO_2e$ (Table I-32). Figure 2 shows the relative impact of avoided emissions and sequestration in protected acreage.

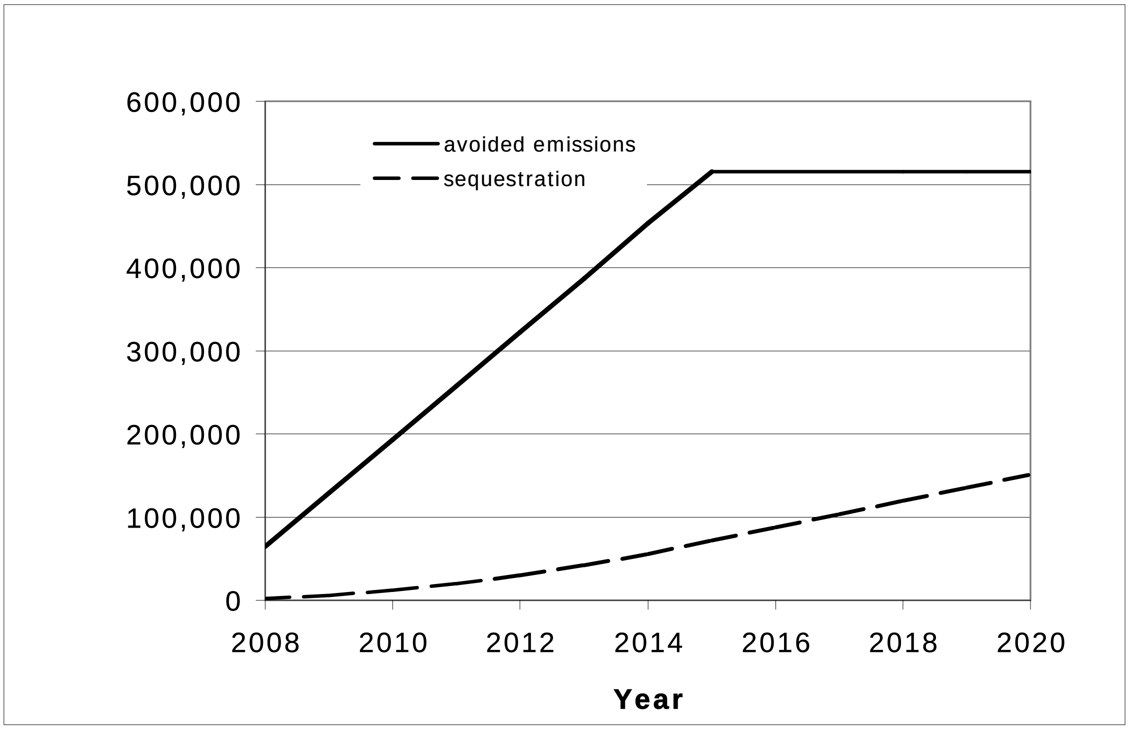
Table I-32. Combined GHG impact of avoided forestland conversion under policy implementation

Year	tC/Year	$MMtCO_2e$/Year
2008	66,429.2	0.2
2009	134,847.8	0.5
2010	205,255.9	0.8
2011	277,653.5	1.0
2012	352,040.4	1.3
2013	428,416.8	1.6
2014	509,270.7	1.9
2015	587,141.4	2.2
2016	603,054.8	2.2
2017	618,968.2	2.3
2018	634,881.7	2.3

Year	tC/Year	MMtCO$_2$e/Year
2019	650,795.1	2.4
2020	666,708.5	2.4
2021	682,621.9	2.5
2022	698,535.3	2.6
2023	714,448.7	2.6
2024	730,362.1	2.7
2025	746,275.5	2.7
Cumulative Total		**34.1**

tC = metric tons of carbon; MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

Figure I-2. Relative impact of avoided emissions from protecting forests and annual sequestration on protected acreage for AFW-6.



4. Economic Analysis

The economic costs of protecting forestland, estimated at $300/acre, were assumed to be the per-acre cost of purchasing conservation easements. This estimate is based on the following:

- Recent and prospective easement purchases for large parcels (roughly 51,000 acres and 75,000 acres) ranged or are projected to range from $200 to $235/acre in northern Minnesota. Since additional easements are likely to protect forests in more densely populated areas in southern parts of the state, the statewide average per-acre easement cost should be somewhat higher than this.[94]

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[94] D. Zumeta, personal communication with J. Jenkins, November 2007.

- Per-acre costs for easements are likely lower for large parcels than for small parcels. Since the bulk of the undisturbed forestland in Minnesota is owned by just a few landowners, few opportunities exist for additional large easement purchases. However, these large parcels do make up a substantial proportion of the forest area statewide, so the per-acre cost is not likely to be very much higher than the $235/acre cost for the most expensive large easement to date.[95]

The net economic costs of protecting forestland are presented in Table I-33. Discounted costs were calculated using a 5% discount rate, with a total NPV of $101 million. The cost-effectiveness of this policy is $2.95/tCO$_2$e avoided.

Table I-33. Summary of the economic costs of protecting forests in AFW-6

Year	Acres Purchased	Total Cost	Discounted Cost
2008	4,616	$1,384,929	$1,384,929
2009	9,233	$2,769,858	$2,637,960
2010	13,849	$4,154,787	$3,768,514
2011	18,466	$5,539,716	$4,785,415
2012	23,082	$6,924,645	$5,696,923
2013	27,699	$8,309,574	$6,510,769
2014	32,488	$9,746,373	$7,272,894
2015	36,927	$11,077,950	$7,872,892
2016	36,927	$11,077,950	$7,497,993
2017	36,927	$11,077,950	$7,140,945
2018	36,927	$11,077,950	$6,800,900
2019	36,927	$11,077,950	$6,477,048
2020	36,927	$11,077,950	$6,168,617
2021	36,927	$11,077,950	$5,874,873
2022	36,927	$11,077,950	$5,595,118
2023	36,927	$11,077,950	$5,328,683
2024	36,927	$11,077,950	$5,074,937
2025	36,927	$11,077,950	$4,833,273
Cumulative Total			**$100,722,682**

Key Assumptions: See quantification above.

Key Uncertainties

Continuing development of forestland is certain to occur. However, there is uncertainty as to whether the various policy tools listed under the Implementation Mechanisms section can be applied effectively enough on a statewide basis to offset this development and stabilize the forestland base by 2015. Implementing some of these tools would require legislative action and funding, both of which are uncertain.

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[95] Idem.

Additional Benefits and Costs

Additional benefits beyond carbon sequestration resulting from forestland protection include protecting wildlife habitat, water quality, air quality, aesthetics, and public access for forest-based recreation. The potential costs of forest protection include the direct costs of either land or conservation easement acquisition or other land protection programs, as well as opportunity costs for developers and landowners because of development opportunities foregone. The potential impacts of forestland protection programs on local government tax receipts depend on the specific type of program, although limited data suggest that providing services to scattered developments in forestland costs local government more than it returns in tax receipts.

Feasibility Issues

There are methodological challenges involved in measuring carbon stocks in forests. As an imperfect proxy for carbon stocks, acres of forestland is far easier to measure, and is already measured periodically by the USFS/Minnesota DNR cooperative Forest Inventory and Analysis Program.

It would be feasible to create a Minnesota Forest Trust, similar to Minnesota's wetland mitigation banks, to help offset the loss of forestland to development. Doing so would most likely require legislative action and start-up funding.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

AFW-7. Front-End Waste Management Technologies

Policy Description

Front-end waste management technologies promote the reduction of the sheer volume of waste produced, as well as reduction in consumption through incentives, awareness, and increased efficiency. Three major areas of focus in Minnesota are source reduction, organic waste management, and advanced recycling. Source reduction and recycling provide GHG benefits not only from avoided disposal emissions, but also from product life-cycle emission reductions (associated with the manufacture and transport of new packaging and products). Redirecting organic wastes (such as food, yard, and paper) from landfills into composting programs is very effective at reducing GHG emissions.

Policy Design

Goals:

Source Reduction Goal—Achieve a 3% per capita decrease in waste generation by 2025.

Recycling and Composting—Achieve a combined recycling and composting (diversion) rate of 75% by 2025.

Timing:

Source Reduction—Achieve a 0% per capita increase by 2020 and a reduction of waste generation per capita of 3% by 2025.

Recycling and Composting—Achieve a recycling rate of 50% by 2011 and 60% by 2025, and a composting rate of 10% by 2012 and 15% by 2020 (for a total diversion rate of 75% by 2025).

Parties Involved: MPCA, counties and other local units of government, private waste management industry, general private industry (end markets for recycled materials), and Food Residuals Diversion Team (currently staffed from Minnesota Office of Environmental Assistance). These are significant societal changes that will require significant support from policy makers, decision makers, manufacturers, retailers, regulatory agencies, Environmental and Non-profit Organizations, and the general public.

Other: The current increase in waste generation is 1.9%/year. In 2005, Minnesota had a recycling rate of 41%; a composting rate of 5% (although mostly yard waste, 0.02% was source-separated compostables, which represented a doubling from the prior year); and an estimated source reduction rate of 3%. Since the 1989 enactment of legislation based on recommendations of the Governor's Select Committee on Recycling and the Environment (SCORE), annual reports estimate recycling in the state. According to the 2005 SCORE report covering waste management in Minnesota, the rates of recycling have leveled off since 1989 (see Figure 3).[96]

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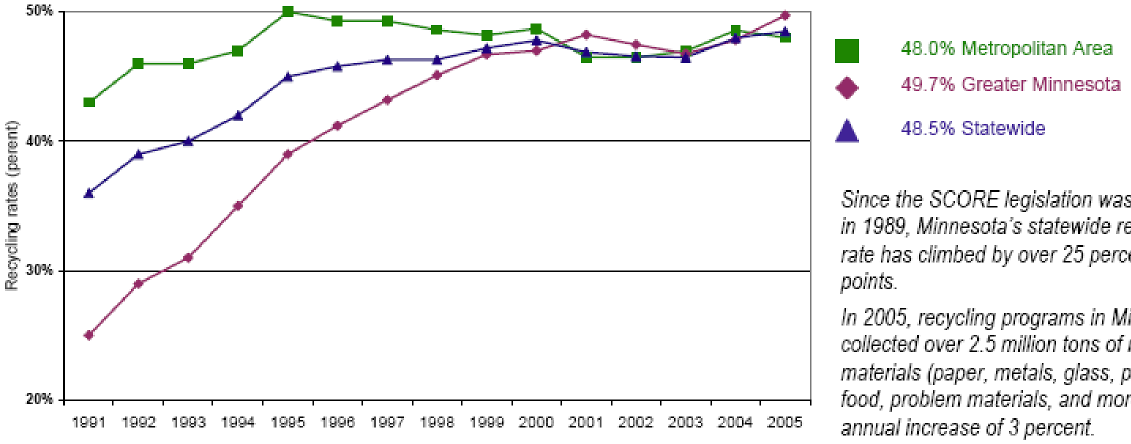
[96] Minnesota Pollution Control Agency, *Report on 2005 SCORE Programs: A Summary of Waste Management in Minnesota*, St. Paul, MN, December 2006. See http://www.pca.state.mn.us/publications/reports/lrp-p2s-3sy07.pdf

Figure I-3. Current Minnesota recycling rates



Since the SCORE legislation was enacted in 1989, Minnesota's statewide recycling rate has climbed by over 25 percentage points.

In 2005, recycling programs in Minnesota collected over 2.5 million tons of recyclable materials (paper, metals, glass, plastic, food, problem materials, and more), an annual increase of 3 percent.

SCORE = [Governor's] Select Committee on Recycling and the Environment.

Implementation Mechanisms

Source Reduction: Reduce the volume of wastes from residential, commercial, and government sectors through programs that reduce overall disposal. Reduction of waste generation at the source of production (including packaging) and of consumption reduces both landfill and waste-to-energy (WTE) combustion emissions as well as upstream production emissions. To achieve the source reduction goals of this policy, Minnesota should

- Identify consumer products and packaging that are neither recyclable nor compostable.
- Create voluntary initiatives, including increasing consumer education about waste and working with manufacturers and retailers to change packaging types and reduce overall packaging. These initiatives would be developed, prioritized, and targeted at products and packaging based on the quantities in the waste stream, the energy intensiveness of their production, and the emissions resulting from their ultimate disposal. Depending on the success of these initiatives, other options could include product stewardship and regulations to reduce use of nonrecyclable and noncompostable materials.
- Increase technical and financial support for existing local, regional, and statewide reduction efforts.
- Develop incentives to encourage local management entities to support and promote reduction efforts.
- Develop international or national packaging regulations (light-weighting of packaging, etc.).
- Expand "Green Building" programs.
- Develop national specifications for construction materials.
- Expand national purchasing guidelines.

- Significantly increase disposal fees, through such options as increased volume- or weight-based pricing or disposal surcharges, with funding directed toward development of increased reduction (and recycling) programs.
- Increase technical and financial support for local and regional education efforts (including support and expansion of MPCA education program).
- Create incentives to encourage corporations to increase reduction and recycling (carbon offsets and credits, etc.).

Organic Waste Recovery: Reduce methane emissions associated with landfilling by reducing the biodegradable fraction of waste placed in landfills (for use in WTE applications, see AFW-8). To achieve the organic waste recovery goals of this policy, Minnesota should:

- Increase recycling of organic wastes (e.g., lawn and garden, food waste, wood, paper) through the use of various methods, including food to people (food recovery) and food to animals.
- Expand composting programs to include community- and home-based organics composting.
- Implement pilot projects, particularly community-based projects with opportunities for energy use.

Recycling: Increase reuse and recycling to limit GHG emissions associated with landfill methane generation, waste combustion, WTE combustion processes, and the extraction of raw materials and energy consumption during the manufacturing process. To achieve the recycling goals of this policy, Minnesota should:

- Fully fund existing reuse and recycling programs.
- Target programs with maximum GHG benefits.
- Expand existing reuse and recycling programs.
- Create new recycling programs.
- Provide incentives for the reuse/recycling of construction materials.
- Develop markets for recycled materials.
- Increase average participation/recovery rates for all existing recycling programs. This could be done via such methods as pay-as-you-throw programs (PAYT), where these are not currently in place, or adjusting existing PAYT programs to be based strictly on the amount of material disposed, or via state enforcement of existing volume-based pricing requirements.
- Increase technical and financial support for existing recycling efforts at the local level.
- Significantly increase disposal fees, brought about by such options as increased volume- or weight-based pricing or disposal surcharges, with funding directed toward development of increased recycling programs.
- Establish national recycled-content requirements.
- Establish national “design for recycling” requirements.

- Increase commercial and industrial recycling.
- Consider statewide mandatory residential and commercial recycling.
- Require up-front processing before disposal (with sufficient education to prevent a potential drop in source recycling).
- Develop recycling requirements for schools and public entities.
- Significantly expand the types of materials collected, increasing from traditional materials to include a number of new materials (more types of plastics, mattresses, demolition and construction materials, industrial wastes, etc.) with associated funding for changes in collection infrastructure.
- Expand traditional and nontraditional recycling end markets.
- Significantly increase efforts to develop generator buy-in.

Related Policies/Programs in Place

Recycle More Minnesota Campaign—MPCA is undertaking a campaign to "reinvigorate recycling." Though Minnesota has one of the nation's highest recycling rates, MPCA intends to increase that rate. This effort is an important means to attaining MPCA's strategic goal to achieve a statewide 50% recycling rate by January 1, 2011. Of garbage sent to the landfill, 75% is potentially recyclable. In fact, MPCA is aware of over 500,000 tons of material (paper, plastic, metals, and glass) from residential waste worth more than $82 million that could be recycled. Even a slight increase in the rate would have a significant impact on reducing GHG emissions.[97]

Minnesota State Resource Recovery Program—This program promotes waste reduction and recycling in Minnesota government agencies. It has targeted programs to reduce office paper waste and the costs and materials associated with publication design and printing; to promote reuse of materials and commodities; and to recycle paper, cans, glass and plastic. The program currently is presenting a recycling challenge to state government buildings.[98]

Increase Organics Recovery—MPCA promotes increased composting of yard waste and other source-separated organics. Applying compost to soils sequesters carbon by utilizing the short-term carbon cycle. In 2005, about 19,000 tons of compost were created and used as soil amendment, capturing about 1% of the organic materials in the solid waste stream. A more aggressive effort could capture 5%–10% of the organics in the solid waste stream. MPCA is also promoting the collection of restaurant and grocery store waste to be used as food for hogs and other recovery options. This does not include any industrial waste, such as vegetable processing

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[97] Minnesota Pollution Control Agency, *Citizen Monitoring of Surface Water Quality: 2005 Report to the Legislature*, St. Paul, MN, January 2005. See http://www.pca.state.mn.us/publications/reports/lrw-sw-1sy06.pdf

[98] Minnesota State Government Resource Recovery Program home page: http://www.rro.state.mn.us/

wastes, biosolids, manure composting, or digestion. There is a large potential here that is as yet untapped. MPCA is working to increase the amount of organic material recovered.[99]

Type(s) of GHG Reductions

CO_2: *Upstream Energy Use Reductions*—The energy and GHG intensity of manufacturing a product/packaging is generally less using recycled feedstocks than from using virgin feedstocks. Source reduction also reduces upstream energy use, since fewer products and packaging are needed.

CH_4: Diverting biodegradable wastes from landfills will decrease methane gas releases from landfills.

Estimated GHG Reductions and Net Costs or Cost Savings

GHG Reduction Potential in 2015, 2025 (MMtCO_2e): 3.4, 7.4, respectively.

Respective breakout by management practice:
    Source Reduction: 0, 3.6.
    Recycling: 3.1, 3.4.
    Composting: 0.29, 0.41.

Net Cost per tCO_2e Reduced:

Source Reduction: $3.
Recycling: –$5 (cost saving).
Composting: $28.

Data Sources: Data on current waste generation and recycling rates were taken from the 2005 SCORE Programs report.[100] As stated in the goals section above, in 2005, Minnesota had a recycling rate of 41% (includes 3% from food waste reuse), a 0.7% municipal solid waste (MSW) and source-separated composting rate, and a waste generation increase of 1.9%/year. MPCA indicates that additional yard waste composting also occurs in the state, which is not reflected in the waste generation and composting estimates provided in the SCORE report.[101] GHG emission reductions were modeled using the U.S. Environmental Protection Agency's (EPA's) WAste Reduction Model (WARM).[102]

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[99] Minnesota Pollution Control Agency, "How To Compost Your Organic Waste." See http://www.reduce.org/compost/index.html

[100] Minnesota Pollution Control Agency, *Report on 2005 SCORE Programs: A Summary of Waste Management in Minnesota*, St. Paul, MN, December 2006. See http://www.pca.state.mn.us/publications/reports/lrp-p2s-3sy07.pdf. The per capita waste generation rate used here was taken as the midpoint between the change in 2004–2005 (1.8%/year) and the increase over the previous 7 years (1998–2005) of 2.0%/year.

[101] M. Rust, MPCA, personal communication with S. Roe, CCS, November 27, 2007.

[102] Version 8, May 2006. From http://www.epa.gov/climatechange//wycd/waste/calculators/WARM_home.html. EPA created WARM to help solid waste planners and organizations track and voluntarily report GHG emission reductions from several different waste management practices. WARM is available as a Web-based calculator and as a Microsoft Excel spreadsheet. WARM calculates and totals GHG emissions of baseline and alternative waste management practices—source reduction, recycling, combustion, composting, and landfilling. The model calculates

Quantification Methods: Table I-34 provides the latest Minnesota MSW generation data from the 2005 SCORE report.

Table I-34. Current Minnesota MSW generation (million tons)

Geographic Area	1991	1998	1999	2000	2001	2002	2003	2004	2005	Changes 2004–2005
Greater Minnesota	1.54	2.07	2.14	2.21	2.32	2.37	2.41	2.53	2.56	1.3%
Metropolitan Area	2.37	3.22	3.30	3.42	3.42	3.49	3.51	3.45	3.52	2.1%
Minnesota	3.90	5.29	5.44	5.63	5.74	5.86	5.92	5.98	6.09	1.8%

Projections for waste management in Minnesota were developed based on the 41% current level of recycling and information provided in the 2005 SCORE report. Note that this 41% includes 3% that could be categorized as food waste (organics) reuse, instead of recycling. The BAU waste management projection for Minnesota is provided in Table I-35.

Table I-35. BAU waste management projection for Minnesota

Waste Management Parameter	2005	2010	2015	2020	2025
	Tons				
MSW generation (1.9%/year growth 1998–2005)	6,090,000	6,690,957	7,351,215	8,076,627	8,873,623
MSW recycled (38% of generation)	2,320,290	2,549,254	2,800,813	3,077,195	3,380,850
Organics reuse (3% of generation)	171,147	188,036	206,591	226,977	249,375
MSW disposed in landfills	2,256,299	2,478,949	2,723,569	2,992,329	3,287,610
Waste-to-energy (35% of waste not recycled or composted)	1,245,103	1,367,968	1,502,959	1,651,269	1,814,215
On-site disposal (2% of waste not recycled or composted)	71,971	79,073	86,876	95,449	104,868
MSW and source-separated compost (0.7% of waste not recycled or composted)	25,190	27,676	30,407	33,407	36,704
Growth Data	**2005**	**2010**	**2015**	**2020**	**2025**
Minnesota population (from I&F)	5,197,200	5,452,500	5,693,700	5,909,400	6,099,500
MSW generation per capita (tons/person)	1.17	1.23	1.29	1.37	1.45

MSW = municipal solid waste; I&F = Inventory and Forecast.

To estimate the GHG reductions associated with the changes in MSW management between Tables 35 and 36, two different WARM runs were conducted to represent BAU and policy

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emissions in tCe, tCO$_2$e, and energy units (million Btu's) across a wide range of material types commonly found in MSW. For an explanation of the methodology, see the EPA report *Solid Waste Management and Greenhouse Gases: A Life-Cycle Assessment of Emissions and Sinks*, EPA530-R-02-006, available at: http://epa.gov/climatechange/wycd/waste/SWMGHGreport.html scenario waste management in 2015 and 2020.[103] WARM provided estimates of GHG reductions due to changes in landfilling practices (including subsequent landfill methane emissions), source reduction, and increased recycling. For source reduction and recycling, WARM estimates life-cycle GHG reductions associated with lower energy use from fewer products and packaging being manufactured and fewer raw (virgin) materials being used.

Table I-36. Waste management projections for Minnesota including policy goals

Waste Management Parameter	2005	2010	2015	2020	2025
	Tons				
MSW generation (based on source reduction goals)	6,090,000	6,690,957	7,351,215	7,985,197	7,990,345
MSW source reduced*	—	—	—	91,431	883,278
MSW recycled (2011, 50% rate; 2025, 60% rate)†	2,320,290	3,010,930	3,749,120	4,312,006	4,554,497
Organics reuse (3% of generation)	171,147	188,036	206,591	224,408	224,553
MSW disposed in landfills (after incremental recycling and composting)	2,363,608	1,998,589	1,438,339	1,131,023	979,776
Waste-to-energy (35% of waste not recycled)‡	1,304,320	1,273,289	1,246,325	1,270,924	1,188,804
On-site disposal (2%)§	75,394	73,601	72,042	73,464	68,717
MSW and source-separated compost (2012, 10%; 2020, 15%)	26,388	334,548	845,390	1,197,780	1,198,552
Growth Data	**2005**	**2010**	**2015**	**2020**	**2025**
MSW generation per capita (tons/person)	1.17	1.23	1.29	1.35	1.31

MSW = municipal solid waste.

* The analysis assumes that negative growth in per capita generation is not achieved until 2020.

† The recycling targets include the business-as-usual 3% organics reuse estimates.

‡ Waste-to-energy volumes remaining after source reduction and recycling.

§ The analysis assumes that on-site disposal continues at 2% of generation.

To estimate the amount of waste by category in the waste stream, information on recycled/composted quantities was taken from the 2005 SCORE report. Also, the MPCA 2005 SCORE Report provided some information on the characteristics of waste that is not recycled or composted from a 1999 waste sort (see Table I-37).[104]

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[103] Optimal GHG reductions from the waste sector will be achieved by accomplishing the AFW-7 goals. However, the continued consideration of waste management methods identified in AFW-8 is necessary to address any shortcomings in achieving the AFW-7 goals and to ensure further reductions in GHG emissions from the waste sector.

[104] Minnesota Pollution Control Agency, *Report on 2005 SCORE Programs: A Summary of Waste Management in Minnesota*, St. Paul, MN, December 2006. See http://www.pca.state.mn.us/publications/reports/lrw-sw-1sy06.pdf. The report notes that 34% of waste is paper, 11% is plastic, 26% is organics (e.g., food, landscaping), 5% is metals, and 3% is glass.

Table I-37. Profile for non-recycled waste in Minnesota

Component	Weight
Paper	34%
Organics	26%
Mixed plastics	11%
Mixed metals	5%
Glass	3%
Other	21%

To assess the benefits of source reduction and recycling, additional details are needed for the first three components in Table I-37 (paper, organics, and mixed plastics). Data from EPA's national assessment of solid waste disposal were used for this purpose.[105] The results are shown in Table I-38.

Table I-38. Detailed profiles for nonrecycled waste components

Assumed Mixed Landfilled Waste Category Profiles	Weight
% of Discarded Paper	
Corrugated cardboard	31.4%
Magazines/third-class mail	12.6%
Newspaper	3.2%
Office paper	5.9%
Phone books	1.3%
Textbooks	2.0%
Mixed paper, broad	43.6%
% of Discarded Organics	
Food waste	70.0%
Yard trimmings	30.0%
% of Discarded Plastics	
HDPE (high-density polyethylene)	16.7%
LDPE (low-density polyethylene)	31.6%
PET (polyethylene terephthalate)	10.4%
Other (assumed mixed plastics)	41.3%

For the modeling conducted for this policy analysis, the following WARM options were selected: methane generation from landfilled waste is collected; collected methane is used for energy recovery (based on the 2004 national average methane collection); and default distances of 20 miles were used between the generator and the landfill, recycling facility, composting facility, or WTE plant.[106]

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[105] EPA, Office of Solid Waste, *Municipal Solid Waste in the United States: 2005 Facts and Figures*, EPA530-R-06-011, Washington, DC, October 2006. See http://www.epa.gov/epaoswer/non-hw/muncpl/pubs/mswchar05.pdf

[106] In Minnesota's more rural communities, distances between waste generators and waste management facilities could be much greater than 20 miles; however, data were not available to develop a weighted-average value that would represent changes in waste management throughout the state.

In 2015, WARM predicted that the proposed shifts in waste management practices will achieve 3.4 MMtCO$_2$e in GHG reductions (2.9 MMtCO$_2$e from recycling, 0.49 MMtCO$_2$e from reduced landfilling, 0.17 MMtCO$_2$e from composting, and a net emission of 0.16 MMtCO$_2$e from reduced WTE combustion). The reduced landfilling benefit is a result of diversion created through recycling and composting. In 2025, WARM predicted GHG reductions overall were 7.4 MMtCO$_2$e combined for all changes in waste management practices (source reduction achieved reductions of 3.5 MMtCO$_2$e; recycling, reductions of 3.2 MMtCO$_2$e; landfilling, reductions of 0.58 MMtCO$_2$e; composting, reductions of 0.23 MMtCO$_2$e; and lower WTE combustion resulted in a net increase of 0.075 MMtCO$_2$e).

In 2025, the reductions in landfilling emissions are attributed to reductions of decomposable wastes (e.g., organics, paper) going to landfills resulting from all three changes in waste management practices: source reduction, recycling, and composting. To provide a rough estimate of the fraction of the reduced landfilling benefit applicable to each practice, CCS developed a breakout of the amount of decomposable waste diverted from landfills via each practice. The results were source reduction = 18%, composting = 36%, and enhanced recycling = 46%. The same percentages were used to allocate the WARM-estimated emissions increase associated with lower WTE combustion. After adding the fraction of the reduced landfilling benefit and WTE dis-benefit to each practice, the GHG reduction results in 2025 were estimated to be source reduction = 3.6 MMtCO$_2$e, recycling = 3.4 MMtCO$_2$e, and composting = 0.41 MMtCO$_2$e. The same approach was used to estimate the benefits for each practice in 2015 (however, based on policy design, no source reduction is yet occurring in 2015).

Table I-39 shows the 2025 WARM input data representing BAU waste management.

Table I-39. 2025 BAU waste management input data to WARM

Material	Tons Generated	Tons Recycled	Tons Landfilled	Tons Combusted	Tons Composted
Aluminum cans	39,904	39,904	—		N/A
Steel cans	30,980	30,980	—		N/A
Copper wire					N/A
Glass	272,697	174,069	98,628		N/A
HDPE	64,368	3,975	60,393		N/A
LDPE	114,277		114,277		N/A
PET	42,388	4,778	37,610		N/A
Corrugated cardboard	883,177	532,192	350,985		N/A
Magazines/third-class mail	191,399	50,558	140,841		N/A
Newspaper	323,851	288,082	35,769		N/A
Office paper	125,729	59,780	65,949		N/A
Phone books	17,052	2,521	14,531		N/A
Textbooks	22,356		22,356		N/A
Dimensional lumber	143,694	143,694	—		N/A
Medium-density fiberboard					N/A
Food scraps	598,345	N/A	598,345	—	
Yard trimmings	293,138	N/A	256,434	36,704	
Grass		N/A			
Leaves		N/A			

Branches		N/A			
Mixed paper (general)	900,327	412,972	487,355		N/A
Mixed paper (primarily residential)		—			N/A
Mixed paper (primarily from offices)					N/A
Mixed metals	807,612	643,231	164,381		N/A
Mixed plastics	210,215	60,859	149,356		N/A
Mixed recyclables	1,243,482	898,283	345,199		N/A
Mixed organics	345,199	N/A	345,199		
Mixed municipal solid waste	1,814,215	N/A	—	1,814,215	N/A
Carpet	243	243	—		N/A
Personal computers	10,240	10,240	—		N/A
Clay bricks		N/A		N/A	N/A
Concrete[*]				N/A	N/A
Fly ash[†]				N/A	N/A
Tires[‡]	25,017	25,017	—		N/A

N/A = not applicable; HDPE = high-density polyethylene; LDPE = low-density polyethylene; PET = polyethylene terephthalate.

[+] Recycled concrete is used as aggregate in the production of new concrete.

[†] Recycled fly ash is utilized to displace Portland cement in concrete production.

[‡] Recycling tires is defined in this analysis as retreading and does not include other recycling activities (e.g., crumb rubber applications).

Table I-40 provides the 2025 WARM input for waste management under the policy scenario (incorporating all components: source reduction, recycling, and composting). For the data in Table I-40, effort was made to achieve as much consistency as possible with the policy scenario projection from Table I-36; however, some small differences remain due to an incomplete understanding of waste characteristics (individual components of the Minnesota solid waste stream), limitations of modeling within WARM (inability to model source reduction within mixed waste categories), and data rounding.

Table I-40. 2025 policy scenario waste management input data to WARM

Material	Baseline Generation	Tons Source Reduced	Tons Recycled	Tons Landfilled	Tons Combusted	Tons Composted
Aluminum cans	39,904	—	39,904			N/A
Steel cans	30,980	—	30,980			N/A
Copper wire	—					N/A
Glass	272,697	39,946	232,751	—	—	N/A
HDPE	64,368	50,000	3,975	10,393	—	N/A
LDPE	114,277	98,785		15,492	—	N/A
PET	42,388	37,610	4,778	—	—	N/A
Corrugated cardboard	883,177	152,938	708,239	22,000		N/A
Magazines/third-class mail	191,399	140,841	50,558	—		N/A
Newspaper	323,851	35,769	288,082	—		N/A
Office paper	125,729	65,949	59,780	—		N/A
Phone books	17,052	14,531	2,521	—		N/A
Textbooks	22,356	22,356		—		N/A
Dimensional lumber	143,694	—	143,694			N/A
Medium-density fiberboard	—					N/A
Food scraps	598,345	N/A	N/A	—	598,345	
Yard trimmings	293,138	N/A	N/A	—	293,138	

Material	Baseline Generation	Tons Source Reduced	Tons Recycled	Tons Landfilled	Tons Combusted	Tons Composted
Grass	—	N/A	N/A			
Leaves	—	N/A	N/A			
Branches	—	N/A	N/A			
Mixed paper (general)	900,327	N/A	647,701	252,626		N/A
Mixed paper (residential)	—	N/A				N/A
Mixed paper (office)	—	N/A				N/A
Mixed metals	807,612	N/A	760,686	46,926		N/A
Mixed plastics	210,215	N/A	178,224	31,991		N/A
Mixed recyclables	1,243,482	N/A	1,243,482	—		N/A
Mixed organics	345,199	N/A	N/A	38,130	307,069	
Mixed municipal solid waste	1,814,215	N/A	N/A	562,427	1,188,804	N/A
Carpet	243		243			N/A
Personal computers	10,240		10,240			N/A
Clay bricks	—		N/A		N/A	N/A
Concrete[*]	—	N/A			N/A	N/A
Fly ash[†]	—	N/A			N/A	N/A
Tires[‡]	25,017	25,017				N/A

N/A = not applicable; HDPE = high-density polyethylene; LDPE = low-density polyethylene; PET = polyethylene terephthalate.

[*] Recycled concrete is used as aggregate in the production of new concrete.

[†] Recycled fly ash is utilized to displace Portland cement in concrete production.

[‡] Recycling tires is defined in this analysis as retreading and does not include other recycling activities (e.g., crumb rubber applications).

Table I-41 provides a summary of the overall 2025 GHG benefits achieved through source reduction, recycling, and composting (7.4 MMtCO$_2$e/year).

Table I-41. Combined 2025 policy scenario GHG benefits from WARM

Material	Source Reduction (tons)	Incremental GHG Emissions from Source Reduction (tCO$_2$e)	Incremental Recycling (tons)	Incremental GHG Emissions From Recycling (tCO$_2$e)	Incremental Landfilling (tons)	Incremental GHG Emissions From Landfilling (tCO$_2$e)	Incremental Combustion (tons)	Incremental GHG Emissions From Combustion (tCO$_2$e)	Incremental Composting (tons)	Incremental GHG Emissions From Composting (tCO$_2$e)	Total Incremental GHG Emissions (tCO$_2$e)
Aluminum cans	0	0	0	0	0	0	0	0	N/A	N/A	0
Steel cans	0	0	0	0	0	0	0	0	N/A	N/A	0
Copper cire	0	0	0	0	0	0	0	0	N/A	N/A	0
Glass	39,946	(22,882)	58,682	(16,305)	(98,628)	(3,748)	0	0	N/A	N/A	(42,935)
HDPE	50,000	(89,314)	0	0	(50,000)	(1,900)	0	0	N/A	N/A	(91,215)
LDPE	98,785	(223,959)	0	0	(98,785)	(3,754)	0	0	N/A	N/A	(227,713)
PET	37,610	(78,745)	0	0	(37,610)	(1,429)	0	0	N/A	N/A	(80,174)
Corrugated cardboard	152,938	(854,914)	176,047	(547,730)	(328,985)	(131,696)	0	0	N/A	N/A	(1,534,340)
Magazines/third-class mail	140,841	(1,218,498)	0	0	(140,841)	42,404	0	0	N/A	N/A	(1,176,094)
Newspaper	35,769	(174,354)	0	0	(35,769)	31,053	0	0	N/A	N/A	(143,301)
Office paper	65,949	(527,541)	0	0	(65,949)	(128,107)	0	0	N/A	N/A	(655,648)
Phone books	14,531	(91,865)	0	0	(14,531)	12,615	0	0	N/A	N/A	(79,249)
Text books	22,356	(204,910)	0	0	(22,356)	(43,427)	0	0	N/A	N/A	(248,337)
Dimensional lumber	0	0	0	0	0	0	0	0	N/A	N/A	0
Medium-density fiberboard	0	0	0	0	0	0	0	0	N/A	N/A	0
Food scraps	N/A	N/A	N/A	N/A	(598,345)	(433,024)	0	0	598,345	(118,809)	(551,834)
Yard trimmings	N/A	N/A	N/A	N/A	(256,434)	56,166	0	0	256,434	(50,918)	5,247
Grass	N/A	N/A	N/A	N/A	0	0	0	0	0	0	0
Leaves	N/A	N/A	N/A	N/A	0	0	0	0	0	0	0
Branches	N/A	N/A	N/A	N/A	0	0	0	0	0	0	0
Mixed paper, broad	N/A	N/A	234,729	(830,223)	(234,729)	(81,734)	0	0	N/A	N/A	(911,957)
Mixed paper, residential	N/A	N/A	0	0	0	0	0	0	N/A	N/A	0
Mixed paper, office	N/A	N/A	0	0	0	0	0	0	N/A	N/A	0
Mixed metals	N/A	N/A	117,455	(617,513)	(117,455)	(4,464)	0	0	N/A	N/A	(621,977)
Mixed plastics	N/A	N/A	117,365	(175,361)	(117,365)	(4,460)	0	0	N/A	N/A	(179,821)

Material	Source Reduction (tons)	Incremental GHG Emissions from Source Reduction (tCO_2e)	Incremental Recycling (tons)	Incremental GHG Emissions From Recycling (tCO_2e)	Incremental Landfilling (tons)	Incremental GHG Emissions From Landfilling (tCO_2e)	Incremental Combustion (tons)	Incremental GHG Emissions From Combustion (tCO_2e)	Incremental Composting (tons)	Incremental GHG Emissions From Composting (tCO_2e)	Total Incremental GHG Emissions (tCO_2e)
Mixed recyclables	N/A	N/A	345,199	(1,005,871)	(345,199)	(48,143)	0	0	N/A	N/A	(1,054,014)
Mixed organics	N/A	N/A	N/A	N/A	(307,069)	(72,546)	0	0	307,069	(60,973)	(133,519)
Mixed municipal solid waste	N/A	N/A	N/A	N/A	562,427	238,442	(625,411)	75,791	N/A	N/A	314,233
Carpet	0	0	0	0	0	0	0	0	N/A	N/A	0
Personal computers	0	0	0	0	0	0	0	0	N/A	N/A	0
Clay bricks	0	0	N/A	N/A	0	0	N/A	N/A	N/A	N/A	0
Concrete	N/A	N/A	0	0	0	0	N/A	N/A	N/A	N/A	0
Fly ash	N/A	N/A	0	0	0	0	N/A	N/A	N/A	N/A	0
Tires	0	0	0	0	0	0	0	0	N/A	N/A	0
Total	**658,725**	**(3,486,982)**	**1,049,477**	**(3,193,002)**	**(2,307,623)**	**(577,753)**	**(625,411)**	**75,791**	**1,161,848**	**(230,701)**	**(7,412,648)**

GHG = greenhouse gas; tCO_2e = tons of carbon dioxide equivalent; N/A = not applicable; HDPE = high-density polyethylene; LDPE = low-density polyethylene; PET = polyethylene terephthalate.

Costs

Source Reduction—A net cost for Minnesota to implement source reduction programs of $60/ton MSW reduced was provided by MPCA.[107] This value was derived from an MPCA program on reducing junk mail. In addition to the program costs to the state, other cost elements include the avoided costs for collecting and transporting the waste to a landfill or other disposal site. For the purposes of this analysis, it was assumed that the waste would have been landfilled, so the landfill tipping fee, estimated at $36/ton, would be avoided.[108] It was assumed that the cost for collecting the waste would not be avoided, since weekly collection of the remaining household/business waste would still be needed. It was further assumed that program implementation costs would begin in 2015, although reductions would not begin until 2016. Table I-42 provides a summary of the costs estimated for the source reduction element of this policy. Cumulative reductions are nearly 20 MMtCO$_2$e through the policy period. A cost-effectiveness of $3/tCO$_2$e was calculated, along with an NPV of $59 million.

Table I-42. Cost analysis results for source reduction

Year	Tons Reduced	Avoided Landfill Tipping Fee (2007$)	Program Costs (2007$)	Net Source Reduction Costs (2007$)	Discounted Costs (2007 MM$)	GHG Reductions (MMt)	Cost-Effective-ness ($/tCO$_2$e)
2008	—	—	—	—	—		
2009	—	—	—	—	—		
2010	—	—	—	—	—		
2011	—	—	—	—	—		
2012	—	—		—	—		
2013	—	—	—	—	—		
2014	—	—	—	—	—		
2015	—	—	—	—	—	—	
2016	88,328	$3,179,801	$5,299,668	$2,119,867	$1.4	0.36	
2017	176,656	$6,359,601	$10,599,336	$4,239,734	$2.7	0.72	
2018	264,983	$9,539,402	$15,899,004	$6,359,601	$3.9	1.08	
2019	353,311	$12,719,203	$21,198,672	$8,479,469	$5.0	1.44	
2020	441,639	$15,899,004	$26,498,340	$10,599,336	$5.9	1.79	
2021	529,967	$19,078,804	$31,798,007	$12,719,203	$6.7	2.15	
2022	618,295	$22,258,605	$37,097,675	$14,839,070	$7.5	2.51	
2023	706,622	$25,438,406	$42,397,343	$16,958,937	$8.2	2.87	
2024	794,950	$28,618,207	$47,697,011	$19,078,804	$8.7	3.23	
2025	883,278	$31,798,007	$52,996,679	$21,198,672	$9.2	3.59	
Total				**$116,592,694**	**$59**	**19.7**	**$3**

MM$ = million dollars; $/tCO$_2$e = dollars per ton of carbon dioxide equivalent.

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[107] MPCA, program costs for junk mail source reduction program; K. McDonald, personal communication with S. Roe, CCS, December 14, 2007.

[108] Average based on input from two sources: J. Ketchum, Waste Management, personal communication with S. Roe, CCS, December 5, 2007: current tipping fee range is $26–$28/ton; T. Troolin, St. Louis County, personal communication with S. Roe, CCS, November 15, 2007: $45.50/ton, including taxes.

Recycling—The net cost of increased recycling rates in Minnesota was estimated by adding the increased costs of collection for two-stream recycling, revenue obtained for the value of recycled materials, and avoided landfill tipping fees. The additional cost for separate curbside collection of recyclables is \$2.50/household/month.[109] The tipping cost paid to a recycler is estimated to be \$10/ton.[110] The avoided cost for landfill tipping is \$36/ton.[111] CCS also factored in the commodity value of recycled materials with a value of \$35/ton.[112] Table I-43 provides the results of the cost analysis. The analysis assumes that costs begin to be incurred in 2008; however, GHG reductions do not begin until 2009. The estimated cost savings result in an NPV of –\$207 million. Cumulative reductions are over 45 $MMtCO_2e$, and the estimated cost-effectiveness is –\$5/tCO_2e.

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[109] T. Brownell, Eureka Recycling, personal communication with S. Roe, CCS, December 17, 2007. This value compares favorably with data provided to the AFW Technical Work Group (T. Troolin, St. Louis County) on recycling costs incurred by Minnesota counties.

[110] J. Ketchum, Waste Management, personal communication with S. Roe, CCS, November 20, 2007.

[111] Average based on input from two sources: J. Ketchum, Waste Management, personal communication with S. Roe, CCS, December 5, 2007: current tipping fee range is \$26–\$28/ton; T. Troolin, St. Louis County, personal communication with S. Roe, CCS, November 15, 2007: \$45.50/ton, including taxes.

[112] T. Brownell, Eureka Recycling, personal communication with S. Roe, CCS, December 17, 2007. This value compares to a wide range of weighted commodity value provided by T. Troolin, St. Louis County. The weighted commodity value range is estimated to be about \$25–\$70/ton, with the higher end representing current values. CCS selected the value of \$35/ton as a conservative estimate for this analysis.

Table I-43. Cost analysis results for recycling

Year	Tons Reduced	Households in Program	Annual Collection Cost (2007$)	Annual Recycled Material Revenue (2007$)	Landfill Tip Fees Avoided (2007$)	Net Policy Cost (Recycling) (2007$)	Discounted Costs (MM$)	GHG Reductions (MMt)	Cost-Effective-ness ($/tCO$_2$e)
2008	—	144,037	$4,321,112	—	—	$4,321,112	$4.3	—	
2009	137,214	288,074	$8,642,223	$4,802,485	$4,939,699	–$1,099,961	–$1.0	0.44	
2010	273,640	432,111	$12,963,335	$9,577,402	$9,851,042	–$6,465,109	–$5.9	0.88	
2011	415,201	576,148	$17,284,446	$14,532,032	$14,947,233	–$12,194,818	–$10.5	1.33	
2012	423,090	720,185	$21,605,558	$14,808,140	$15,231,230	–$8,433,812	–$6.9	1.77	
2013	572,721	864,222	$25,926,670	$20,045,238	$20,617,959	–$14,736,528	–$11.5	2.21	
2014	655,744	1,008,259	$30,247,781	$22,951,049	$23,606,793	–$16,310,061	–$12.2	2.65	
2015	741,716	1,152,296	$34,568,893	$25,960,044	$26,701,760	–$18,092,911	–$12.9	3.10	
2016	755,808	1,175,032	$35,250,950	$26,453,285	$27,209,093	–$18,411,429	–$12.5	3.13	
2017	846,501	1,197,767	$35,933,007	$29,627,523	$30,474,024	–$24,168,539	–$15.6	3.16	
2018	862,584	1,220,502	$36,615,064	$30,190,446	$31,053,030	–$24,628,412	–$15.1	3.20	
2019	958,234	1,243,237	$37,297,121	$33,538,176	$34,496,409	–$30,737,464	–$18.0	3.23	
2020	1,010,403	1,265,973	$37,979,179	$35,364,114	$36,374,518	–$33,759,454	–$18.8	3.26	
2021	1,014,178	1,288,708	$38,661,236	$35,496,233	$36,510,411	–$33,345,408	–$17.7	3.30	
2022	990,126	1,311,443	$39,343,293	$34,654,393	$35,644,519	–$30,955,620	–$15.6	3.33	
2023	964,623	1,334,178	$40,025,350	$33,761,791	$34,726,414	–$28,462,855	–$13.7	3.37	
2024	937,639	1,356,914	$40,707,407	$32,817,348	$33,754,987	–$25,864,928	–$11.8	3.40	
2025	949,094	1,379,649	$41,389,464	$33,218,277	$34,167,371	–$25,996,183	–$11.3	3.43	
Total						**–$349,342,380**	**–$207**	**45.2**	**–$5**

MM$ = million dollars; MMt = million metric tons; $/tCO$_2$e = dollars per ton of carbon dioxide equivalent.

Composting—The net costs for increased composting in Minnesota were estimated by adding the additional costs for collection with the net costs for composting operations. The net cost for composting operations is the sum of the annualized capital and operating costs of composting, increased collection fees, revenue generated through the sale of compost, and the avoided tipping fees for landfilling. Information on the capital and operating costs of composting facilities was received from Cassella Waste Management during the analysis of a similar option in Vermont.[113] These data are summarized in Table I-44.

Table I-44. Cost information for composting facilities

Annual Volume (tons)	Capital Cost (2007 $,000)	Operating Cost ($/ton)
<1,500	$75	$25
1,500–10,000	$200	$50
10,000–30,000	$2,000	$40
30,000–60,000+	$8,000	$30

CCS assumed that the composting facilities to be built within the policy period would tend to be from the largest category (achieving the most efficient operating costs) shown in Table I-44. The composting volumes in 2015 and 2025 shown in Table I-35 suggest the need for about 16 large composting operations by 2015 and another 3 large operations by 2025. To annualize the capital costs for these facilities, CCS assumed a 15-year operating life and a 5% interest rate. Other cost assumptions include a landfill tipping fee of $36/ton,[114] an additional source-separated organics collection fee of $2.50/household/month (as used above in the recycling element), and a compost value of $10/ton.[115]

Table I-45 presents the results of the cost analysis for composting. GHG reductions were assumed not to begin until 2009, and the cumulative reductions estimated were 4.9 $MMtCO_2e$. An NPV of $137 million was estimated, along with a cost-effectiveness of $28/$tCO_2e$.

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[113] P. Calabrese, Cassella Waste Management, personal communication with S. Roe, CCS, June 5, 2007.

[114] J. Ketchum, Waste Management, personal communication with S. Roe, CCS, December 5, 2007. Current fees are $26–$28/ton. The midpoint was assumed to remain static throughout the policy period.

[115] G. Black, MPCA, personal communication with S. Roe, CCS, November 15, 2007. These values were assumed to remain constant over the policy period.

Table I-45. Cost analysis results for composting

Year	Annual Cost O&M (2007$)	Capital Cost (2007$)	Annualized Capital Cost (2007$)	Avoided Landfill Tipping Fees (2007$)	Value of Composted Material (2007$)	Total Annual Composting Cost (2007$/ton)	Annual Collection Cost (2007$)	House-holds in Program	Tons of Waste Composted	Total Annual Composting Cost (2007$)	Discounted Costs (2007MM$)	GHG Reductions (MMtCO$_2$e)	Cost Effective-ness ($/tCO$_2$e)
2008	$2,769,505	$16,000,000	$1,541,477	$3,323,406	$923,168	$64,407	$1,723,748	57,458	92,317	$1,788,155	$1.8	0	
2009	$5,539,011	$16,000,000	$3,082,953	$6,646,813	$1,846,337	$128,814	$3,447,497	114,917	184,634	$3,576,311	$3.4	0.04	
2010	$8,308,516	$16,000,000	$4,624,430	$9,970,219	$2,769,505	$193,221	$5,171,245	172,375	276,951	$5,364,466	$4.9	0.09	
2011	$11,078,021	$16,000,000	$6,165,906	$13,293,625	$3,692,674	$257,628	$6,894,993	229,833	369,267	$7,152,622	$6.2	0.13	
2012	$13,847,526	$16,000,000	$7,707,383	$16,617,032	$4,615,842	$322,036	$8,618,741	287,291	461,584	$8,940,777	$7.4	0.17	
2013	$16,617,032	$16,000,000	$9,248,860	$19,940,438	$5,539,011	$386,443	$10,342,49`0	344,750	553,901	$10,728,932	$8.4	0.22	
2014	$19,386,537	$16,000,000	$10,790,336	$23,263,844	$6,462,179	$450,850	$12,066,238	402,208	646,218	$12,517,088	$9.3	0.26	
2015	$22,156,042	$16,000,000	$12,331,813	$26,587,251	$7,385,347	$515,257	$13,789,986	459,666	738,535	$14,305,243	$10.2	0.30	
2016	$22,614,885	$0	$12,331,813	$27,137,862	$7,538,295	$270,541	$14,075,571	469,186	753,830	$14,346,112	$9.7	0.31	
2017	$23,073,728	$8,000,000	$13,102,551	$27,688,474	$7,691,243	$796,563	$14,361,157	478,705	769,124	$15,157,719	$9.8	0.33	
2018	$23,532,571	$0	$13,102,551	$28,239,085	$7,844,190	$551,847	$14,646,742	488,225	784,419	$15,198,588	$9.3	0.34	
2019	$23,991,414	$8,000,000	$13,873,289	$28,789,697	$7,997,138	$1,077,869	$14,932,327	497,744	799,714	$16,010,196	$9.4	0.35	
2020	$24,450,257	$0	$13,873,289	$29,340,308	$8,150,086	$833,152	$15,217,912	507,264	815,009	$16,051,065	$8.9	0.36	
2021	$24,909,100	$8,000,000	$14,644,028	$29,890,920	$8,303,033	$1,359,174	$15,503,497	516,783	830,303	$16,862,672	$8.9	0.37	
2022	$25,367,943	$0	$14,644,028	$30,441,531	$8,455,981	$1,114,458	$15,789,083	526,303	845,598	$16,903,541	$8.5	0.38	
2023	$25,826,786	$0	$14,644,028	$30,992,143	$8,608,929	$869,742	$16,074,668	535,822	860,893	$16,944,410	$8.2	0.39	
2024	$26,285,629	$0	$13,102,551	$31,542,755	$8,761,876	–$916,451	$16,360,253	545,342	876,188	$15,443,802	$7.1	0.40	
2025	$26,744,472	$0	$10,019,598	$32,093,366	$8,914,824	–$4,244,120	$16,645,838	554,861	891,482	$12,401,718	$5.4	0.41	
Total											**$137**	**4.9**	**$28**

O&M = operations and maintenance; MM$ = million dollars; GHG = greenhouse gas; MMtCO$_2$e = million metric tons of carbon dioxide equivalent; $/tCO$_2$e = dollars per ton of carbon dioxide equivalent.

Key Assumptions: For the MSW management input data to WARM, the key assumption is that none of the goals would be achieved via existing programs. To the extent that these programs will fully or partly achieve the goals of this policy, the GHG reductions estimated would be lower (no additional penetration from the current MPCA recycling and composting campaigns has been incorporated into the BAU assumptions for this analysis). Therefore, the most important assumption relates to the assumed BAU projection for solid waste management. This BAU forecast is based on current practices and does not factor in the effects of further gains in recycling or composting rates during the policy period. The BAU assumptions are needed to tie into the assumptions used to develop the GHG forecast for the waste management sector, which does not factor in these changes in waste management practices during the policy period (2008–2025). To the extent that these gains in recycling and composting would occur without this policy, the benefits and costs are overstated.

The other key assumptions relate to the use of WARM in estimating life-cycle GHG benefits and the use of the stated assumptions regarding costs for increased source reduction, recycling, and organics recovery (composting in this example) programs.

Another important assumption is that under BAU, the waste directed to landfilling would include methane recovery (75% collection efficiency) and utilization. The need for this assumption is partly based on the limitations of WARM (which does not allow for management of landfilled waste into both controlled and uncontrolled landfills), but is also based on the overall direction of the policy recommendations of AFW-7 and AFW-8. As shown in AFW-8, one of the policy elements is that all waste deposited in landfills by 2020 will be served by a methane collection system capable of achieving 90% collection and control of methane generated during the life span of the landfill.

The cost estimates do not include cost savings that would be achieved by avoiding the need for additional WTE plants.

Key Uncertainties

See Key Assumptions, above—in particular, the assumptions regarding the BAU waste management forecast, which affect the estimated GHG reductions. For the cost analyses, each of the assumptions described above could have a significant impact on the estimated costs and cost savings.

Additional Benefits and Costs

None identified.

Feasibility Issues

The MCCAG recommends that further study be conducted on detailed implementation plans and the real costs impacts on specific Minnesota business and consumer sectors and taxpayers.

The MCCAG recognizes that transforming Minnesota's waste management practices to incorporate these higher levels of source reduction, recycling, and composting will present significant challenges. To provide a sense of what is at stake in terms of GHG reductions, an analysis is presented under the Feasibility Issues section of AFW-8, which quantifies the GHG reductions that would be achieved under a waste management scenario where the goals of this policy are largely unachieved. This future scenario is based on MPCA's most recent solid waste goals (see AFW-8)

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

None.

AFW-8. End-of-Life Waste Management Practices

Policy Description

This policy promotes activities that further reduce GHG production by encouraging the use of energy recovery technologies for materials not managed by AFW-7 (Front-End Waste Management Technologies). It also encourages the use of energy recovery technologies for waste materials for which more desirable front-end waste management alternatives are not available or feasible. These technologies will help reduce GHG emissions from waste management, while producing cleaner energy. They make a two-fold contribution to climate protection, by reducing the discharge of methane and other GHGs into the atmosphere, and replacing fossil fuel burning with recovered energy. For example, the energy created by landfills (methane) can be used to make electric power, space heat, or liquefied natural gas. WTE facilities already in existence in Minnesota generate 100 MW of electricity and 150,000 lbs/hr of steam for heating and cooling and use by other industries. EPA recognizes that for every ton of waste diverted from a landfill to a WTE facility, 0.15 $MtCO_2e$ emissions are prevented.[116]

Policy Design

Goals:

Landfilled Waste—For all waste entering landfills in 2020, capture 90% of the methane generated over the life span of the facility.

Residuals Management—By 2015, achieve a 35% reduction in the landfilling of organic waste through organics recovery (see AFW-7) or WTE. This goal is meant to ensure that any organics not directed to organics management under AFW-7 (e.g., composting) would not be landfilled, but would be sent to WTE for energy recovery, and thus reduce landfilling by 35% . By 2025, develop alternative management methods for materials not managed through AFW-7.

Waste-To-Energy Facilities—By 2020, preprocess all waste entering WTE facilities to remove recoverable materials and enhance energy recovery.

Timing: By 2015, identify which of the available end-of-use practices are best applied to the (1) most energy-intensive materials to produce, (2) the largest GHG-emitting materials, and (3) by type, the materials that are found in the greatest quantity in the end-of-use waste stream.

Parties Involved: MPCA, counties and other local units of government, private waste management industry, general private industry (end markets for recycled materials), Environmental and Non-profit Organizations.

Other: After implementing the upper-hierarchy front-end waste management goals in AFW-7 (reduce, reuse, recycle, compost), the best end-of-life practices should be employed to minimize

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[116] EPA, *Solid Waste Management and Greenhouse Gases: A Life-Cycle Assessment of Emissions and Sinks,* EPA530-R-02-006, Washington, DC, September 2006. See http://epa.gov/climatechange/wycd/waste/SWMGHGreport.html

the release of GHG emissions. MPCA will conduct ongoing evaluation of the success of front-end abatement activities and the environmental viability and GHG-reduction feasibility of different waste management technologies to refine and update information on best practices.

Implementation Mechanisms

Implement programs to achieve goals through:

- Ongoing county solid waste management planning;
- State-based financial and technical assistance programs;
- Tax and other incentives to spur private-sector project development;
- Consideration of optional state system ownership/operation options; and
- Education of the public and opposition groups.

Related Policies/Programs in Place

Currently, nine WTE facilities in Minnesota process 3,800 tons of MSW per day for industrial heat and electrical generation. The total energy reclaimed since 1982, when these facilities first began to come on line, is the equivalent of 12 million tons of coal. Currently, these facilities produce approximately 100 MW of electrical energy, or enough energy to power 110,000 homes. MPCA has a strategic objective to increase the state's WTE capacity by 60% by 2011. In 2005, Minnesota WTE reduced CO_2 and CH_4 gases by an amount equivalent to taking 90,000 cars off the road.

Minnesota has 21 open mixed municipal landfills, the majority which are owned and operated by county governments. Two of these facilities (Waste Management's Elk River Facility, and Allied's Pine Bend Facility) currently generate electricity derived from the collection and combustion of the methane gas generated as a result of waste decomposition. The Burnsville landfill, operated by Waste Management, also operates a landfill gas-to-energy (LFGTE) plant. Waste Management also indicates that the Spruce Ridge landfill will have methane recovery and utilization facilities operating in the spring of 2008.[117] Another facility, Three Rivers Landfill in Kanabec County, will be capturing methane for the production of energy in the near future. Lyon County is currently assessing the potential of an LFGTE project at its county-owned facility. MPCA has been proactive with landfill owners and operators in promoting and encouraging the capture and utilization of this valuable resource.

Type(s) of GHG Reductions

CH_4: Reductions in landfill methane via organics composting/digestion or WTE instead of landfilling. Landfill methane reductions via collection and control (via flaring or, preferentially, via energy utilization).

CO_2: Reduction of fossil fuels and associated GHGs through the generation of electricity from landfill methane or heat/steam or electricity at WTE facilities.

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[117] J. Ketchum, Waste Management, personal communication with S. Roe, CCS, December 5, 2007.

Estimated GHG Reductions and Net Costs or Cost Savings

Two separate analyses were needed for each policy element: (1) a stand-alone analysis, which assumes either that AFW-7 is not recommended or that it largely fails to achieve its stated goals; and (2) an incremental analysis, which addresses the incremental benefits and costs for this policy over and above AFW-7.

GHG Reduction Potential in 2015, 2025 (MMtCO$_2$e): Breakout by policy element, below.

Stand-Alone Estimates

Landfilled Waste: 0.066, 0.73, respectively.
Residuals Management: 0.52, 0.63, respectively.
WTE Preprocessing: 0.37, 0.84, respectively.

Incremental Estimates

Landfilled Waste: 0.023, 0.25, respectively.
Residuals Management: Not applicable.
WTE Preprocessing: 0.17, 0.38, respectively.

Net Cost per tCO$_2$e: Breakout by policy element, below.

Stand-Alone Estimates

Landfilled Waste: $1.
Residuals Management: $80.
WTE Preprocessing: $32.

Incremental Estimates

Landfilled Waste: $3.
Residuals Management: Not applicable.
WTE Preprocessing: $32.

Data Sources: This analysis builds on the analysis conducted for AFW-7. Therefore, the same data sources are applicable to this policy. Additional data sources used in the analysis are provided under the quantification methods section, below.

Quantification Methods:

1. GHG Reductions by Policy Element

A. Methane Recovery From Landfilled Waste. For the waste still entering landfills in 2020 and beyond, CCS used EPA's Landfill Gas Emissions Model (LandGEM) to determine the amount of methane to be generated in subsequent years.[118] According to the policy design, 90% of the methane is to be captured and controlled (either via flaring or for energy recovery). The GHG reductions associated with this capture and control were then compared with a baseline of methane capture and use from information developed by MPCA to support the Minnesota GHG I&F.[119] For both the stand-alone and the incremental analyses, the benefit of the policy is the

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[118] EPA's LandGEM User's Guide can be downloaded from: http://www.epa.gov/ttncatc1/dir1/landgem-v302-guide.pdf. The MS Excel-based spreadsheet model can be downloaded from: http://www.epa.gov/ttncatc1/products.html

[119] P. Ciborowski, MPCA, personal communication and spreadsheet data, supplied to S. Roe, CCS, May 2007.

incremental GHGs reduced per the 90% collection/control requirement, as compared with the baseline.

Stand-Alone Analysis—Based on the results of the modeling to support the analysis of AFW-7, CCS estimated that 2,992,329 tons per year of MSW will be landfilled in 2020 under BAU waste management, rising to 3,287,610 tons by 2025. The annual amounts of waste were entered into LandGEM to estimate methane generation from this waste from 2020 through 2025. Following the LandGEM modeling, the waste was assumed to be placed in landfills in proportion to the 2004 modeled methane emissions from the I&F (i.e., methane emissions are also assumed to be in proportion to the 2004 data). Based on the 2004 modeled methane emissions, the emplacement fractions for sites with LFGTE plants, flares, and no controls are provided in Table I-46.

Table I-46. Assumed 2020 waste emplacement

Landfill Type	Emplacement Fraction	2020 Waste Emplacement (tons)
LFGTE	0.49	723,843
Flared	0.10	147,723
Uncontrolled	0.41	605,665

LFGTE = landfill gas to energy.

For LFGTE and flared landfills, the BAU assumptions for methane collection and control are 75% (in accordance with standard EPA assumptions). The benefit for achieving 90% collection and control in waste landfilled after 2020 was estimated as the difference between BAU collection/control and the policy scenario, shown in Table I-47.

Table I-47. Estimated stand-alone benefit for increased methane recovery

2025 BAU Methane Emissions by Landfill Type			
LFGTE	184,066	tCO_2e/year	Based on 75% collection/control
Flared	38,045	tCO_2e/year	Based on 75% collection/control
Uncontrolled	606,737	tCO_2e/year	
Total	**828,848**	**tCO_2e/year**	
2025 Policy Scenario Stand-Alone Methane Emissions by Landfill Type			
LFGTE	73,627	tCO_2e/year	Based on 90% collection/control
Flared	15,218	tCO_2e/year	Based on 90% collection/control
Uncontrolled	60,674	tCO_2e/year	Based on 90% collection/control
Total	**149,518**	**tCO_2e/year**	
2025 Benefit	**0.68**	**$MMtCO_2e$/year**	BAU emissions minus policy scenario emissions

BAU = business as usual; LFGTE = landfill gas to energy; tCO_2e = tons of carbon dioxide equivalent; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

An additional GHG reduction occurs when the additional methane collected is used for energy. Assuming that the methane recovered from LFGTE sites and uncontrolled sites is used for energy recovery, CCS estimated that an additional 25 million cubic meters (MMm^3) would be available for energy recovery. Using a factor for landfill methane conversion to electricity with a standard engine/generator set (2.54 kilowatt-hours per cubic meter [kWh/m^3]),[120] CCS estimated that 63,575 megawatt-hours (MWh) could be produced with this methane. If this electricity is used to offset fossil-based power in Minnesota, the resulting additional emission reductions would be 45,774 $MtCO_2e$ in 2025 for the stand-alone analysis.[121] Hence, the overall reduction for the stand-alone analysis is 0.73 $MMtCO_2e$ in 2025.

It was assumed that progress toward implementation of this policy element begins in 2015, so emission reductions begin to accrue in 2015. The estimated cumulative reductions are shown in Table I-48 for the stand-alone analysis.

Table I-48. Estimated cumulative reductions for increased methane recovery (stand-alone analysis)

Year	Avoided Emissions ($MMtCO_2e$)
2008	0.00
2009	0.00
2010	0.00
2011	0.00
2012	0.00
2013	0.00
2014	0.00
2015	0.07
2016	0.13
2017	0.20
2018	0.26
2019	0.33
2020	0.40
2021	0.46
2022	0.53
2023	0.59
2024	0.66
2025	0.73
Total	**4.4**

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

Incremental Analysis—The incremental analysis was conducted similarly to the stand-alone analysis, except the waste to be managed via landfilling in the post-2020 time frame is the waste that remains following full implementation of AFW-7. From the AFW-7 analysis, 1,131,023 tons will be landfilled in 2020, and 979,776 tons will be landfilled in 2025 following full implementation of AFW-7. The results for this analysis were that 0.24 $MMtCO_2e$ will be reduced

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[120] US EPA Landfill Methane Outreach Program, Landfill Gas Energy Cost Model (LFGcost), Version 1.4 "Summary Report, Pechan for NC GHG Mitigation Plan—Scenario 4, LFGE Project Type: Standard Reciprocating Engine-Generator Set," March 2, 2007.

[121] Based on an electricity generation emission factor of 0.72 $MtCO_2e$/MWh derived from the Minnesota I&F.

in 2025 via enhanced methane recovery and control, and an additional 0.02 MMtCO$_2$e will be reduced via methane energy utilization (offsetting fossil-based electricity generation).

B. Residuals Management. From the AFW-7 analysis, CCS developed estimates of the organic fraction of waste still being landfilled following the implementation of the source reduction and recycling. Organic wastes under this policy element include food/yard ("organics") waste, paper, and wood waste. For the *stand-alone analysis*, the total organic waste landfilled under BAU was multiplied by 35% to estimate the amount of organic waste targeted for WTE under this policy element. For the *incremental analysis*, the amount of organic waste being utilized under the AFW-7 composting element was subtracted from the amount estimated for the stand-alone analysis to estimate the amount of organic waste remaining for WTE recovery. The quantification of organic waste available for energy recovery is summarized in Table I-49.

Table I-49. Estimated organic waste for waste-to-energy recovery

Waste Management Data	2005	2015	2025
MSW generation (tons; 1.9%/year growth 1998–2005)	6,090,000	7,351,215	8,873,623
BAU MSW disposed in landfills (tons)	2,256,299	2,723,569	3,287,610
Total organics landfilled (tons; 70.5% of landfill waste)*	1,613,254	1,920,116	2,317,765
35% of organics landfilled (tons)†	564,639	672,041	811,218
Incremental organics composted under AFW-7 (tons)	—	814,983	1,161,848
Incremental organics for AFW-8 WTE (tons)‡	—	0	0

MSW = municipal solid waste; BAU = business as usual; WTE = waste to energy. See AFW-7 quantification for more details on BAU waste generation.

* From the 1999 waste sort documented in the Minnesota Pollution Control Agency's (MPCA's) 2005 Solid Waste Management Report: paper (34%), "organics" or food/yard waste (26%), and other (21%). CCS assumed that half of the "Other" category was organic waste (e.g., wood or other).[122]

† These values are used in the stand-alone analysis.

‡ These values are used in the incremental analysis.

As shown in Table I-49, for the *stand-alone analysis*, there are an additional 822,724 tons of organic wastes for WTE utilization. For the *incremental analysis*, the additional organics composted under AFW-7 exceed the 35% of organics targeted under AFW-8, so no additional organic waste is available for WTE. Hence, CCS reported the benefits and costs for the *incremental analysis* as zero.

The benefits of the additional waste managed by WTE plants for the *stand-alone analysis* were estimated using EPA's WARM (see AFW-7 for citations). To do this, further characterization of the waste was needed. Using the same assumptions for landfilled waste characterization as used in the AFW-7 analysis, CCS developed the data shown in Table I-50 for input into WARM. The first step was to divide the waste into the various organics fractions (food/yard waste, paper, and other). This was done using waste sort data from MPCA's *2005 Solid Waste Policy Report* (26%

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[122] Jim Chiles, Anne Gelbmann, and Mark Rust, *2005 Solid Waste Policy Report: Waste Management at a Crossroads*, St. Paul, MN: MPCA, March 2006. See http://www.pca.state.mn.us/publications/reports/lrw-sw-1sy06.pdf

of waste is food/yard; 34% is paper waste; and 21% is "other").[123] CCS assumed that half of the "other" category was organic waste, such as wood waste, yielding a total organics fraction of 70.5%. The organics were further characterized using information on landfilled waste from EPA's *2005 Solid Waste Characteristics Report* (see AFW-7 quantification for citation).

Table I-50. Estimated organic waste tonnages for WTE in WARM

Organics Fraction	2015 Tons	2025 Tons	% of Organics Fraction
Landfilled "Organics" for WTE			
Food waste	495,690	598,345	70%
Yard waste	212,438	256,434	30%
Total	**708,128**	**854,779**	
Landfilled Paper for WTE			
Corrugated cardboard	71,747	86,606	31%
Magazines/third-class mail	28,790	34,753	13%
Newspaper	7,312	8,826	3%
Office paper	13,481	16,273	6%
Phone books	2,970	3,586	1%
Textbooks	4,570	5,516	2%
Mixed paper	99,623	120,255	44%
Total	**228,494**	**275,814**	
Other Organics for WTE			
Mixed organics	100,091	120,820	100%
Total	**672,041**	**811,218**	

WTE = waste to energy.

The 2025 input data to WARM are shown in Tables 51a and 51b.

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[123] Ibid.

Table I-51a. 2025 BAU waste management input data to WARM

Material	Tons Generated	Tons Recycled	Tons Landfilled	Tons Combusted	Tons Composted
Aluminum cans					N/A
Steel cans					N/A
Copper wire					N/A
Glass					N/A
HDPE					N/A
LDPE					N/A
PET					N/A
Corrugated cardboard	122,845		122,845		N/A
Magazines/third-class mail	49,294		49,294		N/A
Newspaper	12,519		12,519		N/A
Office paper	23,082		23,082		N/A
Phone books	5,086		5,086		N/A
Textbooks	7,825		7,825		N/A
Dimensional lumber					N/A
Medium-density fiberboard					N/A
Food scraps	209,421		209,421		
Yard trimmings	89,752		89,752		
Grass					
Leaves					
Branches					
Mixed paper (general)	170,574		170,574		N/A
Mixed paper (primarily residential)					N/A
Mixed paper (primarily from offices)					N/A
Mixed metals					N/A
Mixed plastics					N/A
Mixed recyclables					N/A
Mixed organics	120,820		120,820		
Mixed municipal solid waste					N/A
Carpet					N/A
Personal computers					N/A
Clay bricks					N/A
Concrete*					N/A
Fly ash†					N/A
Tires‡					N/A

N/A = not applicable; HDPE = high-density polyethylene; LDPE = low-density polyethylene; PET = polyethylene terephthalate.

* Recycled concrete used as aggregate in the production of new concrete.

† Recycled fly ash is utilized to displace Portland cement in concrete production.

‡ Recycling tires is defined in this analysis as retreading and does not include other recycling activities (e.g., crumb rubber applications).

Table I-51b. 2025 policy scenario waste management input data to WARM

Material	Baseline Generation	Tons Source Reduced	Tons Recycled	Tons Landfilled	Tons Combusted	Tons Composted
Aluminum cans	—	—				N/A
Steel cans	—	—				N/A
Copper wire	—					N/A
Glass	—	—				N/A
HDPE	—	—				N/A
LDPE	—	—				N/A
PET	—	—				N/A
Corrugated cardboard	122,845	—			122,845	N/A
Magazines/third-class mail	49,294	—			49,294	N/A
Newspaper	12,519	—			12,519	N/A
Office paper	23,082	—			23,082	N/A
Phone books	5,086	—			5,086	N/A
Textbooks	7,825				7,825	N/A
Dimensional lumber	—	—				N/A
Medium-density fiberboard	—					N/A
Food scraps	209,421	N/A	N/A		209,421	
Yard trimmings	89,752	N/A	N/A		89,752	
Grass	—	N/A	N/A			
Leaves	—	N/A	N/A			
Branches	—	N/A	N/A			
Mixed paper (general)	170,574	N/A			170,574	N/A
Mixed paper (residence)	—	N/A				N/A
Mixed paper (office)	—	N/A				N/A
Mixed metals	—	N/A				N/A
Mixed plastics	—	N/A				N/A
Mixed recyclables	—	N/A				N/A
Mixed organics	120,820	N/A	N/A	—	120,820	
Mixed municipal solid waste	—	N/A	N/A	—		N/A
Carpet	—					N/A
Personal computers	—					N/A
Clay bricks	—		N/A		N/A	N/A
Concrete[*]	—	N/A			N/A	N/A
Fly ash[†]	—	N/A			N/A	N/A
Tires[‡]	—					N/A

N/A = not applicable; HDPE = high-density polyethylene; LDPE = low-density polyethylene; PET = polyethylene terephthalate.

[*] Recycled concrete is used as aggregate in the production of new concrete.

[†] Recycled fly ash is utilized to displace Portland cement in concrete production.

[‡] Recycling tires is defined in this analysis as retreading and does not include other recycling activities (e.g. crumb rubber applications).

The WARM results are the sum of reduced landfill methane emissions and GHG emissions offset from fossil fuel combustion using the additional energy in the organic waste directed to

WTE plants. For *stand-alone* reductions, WARM estimated reductions of 0.52 $MMtCO_2e$/year in 2015 and 0.63 $MMtCO_2e$/year in 2025. As described above, the reductions for the AFW-7 *incremental* analysis are zero. For the purposes of estimating cumulative benefits, it was assumed that implementation begins in 2008, but full implementation is not achieved until 2025. The summation of cumulative reductions (8.1 $MMtCO_2e$) is shown in Table I-52.

Table I-52. Estimated cumulative reduction for organic waste to WTE policy element

Year	**Avoided Emissions ($MMtCO_2e$)**
2007	0.000
2008	0.065
2009	0.13
2010	0.20
2011	0.26
2012	0.33
2013	0.39
2014	0.46
2015	0.52
2016	0.53
2017	0.54
2018	0.55
2019	0.56
2020	0.58
2021	0.59
2022	0.60
2023	0.61
2024	0.62
2025	0.63
Total	**8.1**

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

C. Preprocessing of MSW at WTE Plants. Information developed under AFW-7 on waste generation, characterization, and management was used as the starting point for this analysis. In addition, data on current WTE plant combustion of MSW were gathered from the MPCA *2005 Solid Waste Policy Report.*[124] Also, MPCA provided information on the current (2004) levels of MSW burned in refuse-derived fuel (RDF) versus mass burn facilities in the state.[125] This policy element addresses both the existing (BAU) and incremental WTE combusted under the previous AFW-8 policy element. The WTE data are summarized in Table I-53 for both the *stand-alone and incremental* analyses. To estimate the mass of waste that needs to be preprocessed, CCS multiplied the total WTE mass by 75%, since it is assumed that preprocessing is already occurring at RDF facilities.

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[124] Ibid.

[125] P. Ciborowski, MPCA, personal communication and data files, provided to S. Roe, CCS, May 2007.

Table I-53. Estimated future levels of MSW WTE combustion

BAU 2025 WTE Combustion (tons)	1,814,215	From the AFW-7 analysis.
RDF fraction	0.25	Derived from MPCA-supplied data.
Mass burn fraction	0.75	Derived from MPCA-supplied data.
2025 WTE combustion (tons)	1,188,804	Includes the effects of AFW-7 waste management elements.
2025 Additional WTE combustion (tons)	811,218	From previous AFW-8 policy element.
Stand-Alone: **2025 Total Waste Combustion (tons)**	**2,625,433**	For *stand-alone* analysis: BAU combustion plus additional WTE combustion.
Incremental: **2025 Total Waste Combustion (tons)**	**1,188,804**	For *incremental analysis*: WTE combustion after AFW-7 implementation (plus no additional organics to WTE).
Stand-Alone: Mass Burn (tons)	**1,969,075**	75% of WTE needing preprocessing.
Incremental: Mass Burn (tons)	**891,603**	75% of WTE needing preprocessing.

BAU = business as usual; WTE = waste to energy; RDF = refuse-derived fuel; MPCA = Minnesota Pollution Control Agency.

Information from within the WARM documentation was used to estimate the effects of preprocessing the MSW burned within Minnesota's mass-burn plants (based on current practices, 75% is burned in mass-burn plants). As stated above, it was assumed that no additional preprocessing of waste is needed for RDF plants. Since no data were available on the characteristics of waste entering mass-burn plants, CCS used information developed under AFW-7 on the assumed characteristics of landfilled waste as a surrogate profile for MSW entering mass-burn plants. The estimates for waste entering mass-burn WTE plants in 2025 are provided in Table I-54.[126]

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[126] For the stand-alone analysis, the fractions of organics are likely to be higher because of the additional organics directed to WTE under the previous policy element. However, for the purposes of this analysis, the data in Table 54 have not been adjusted.

Table I-54. Estimated 2025 profile of MSW combusted in mass burn WTE plants

MSW Component	Fraction	Stand-Alone 2025 Tons
Glass	0.037	72,850
HDPE	0.005	10,489
LDPE	0.016	30,618
PET	0.053	105,179
Corrugated cardboard	0.083	163,871
Magazines/third-class mail	0.044	85,771
Newspaper	0.011	21,782
Office paper	0.020	40,163
Phone books	0.004	8,850
Textbooks	0.007	13,614
Food scraps	0.224	440,108
Yard trimmings	0.070	137,042
Mixed metals	0.079	154,666
Mixed plastics	0.038	74,373
Mixed recyclables	0.31	609,699
Total		**1,969,075**

MSW = municipal solid waste; HDPE = high-density polyethylene; LDPE = low-density polyethylene; PET = polyethylene terephthalate; WTE = waste to energy.

Table I-55 summarizes the calculation of the incremental benefit associated with preprocessing the waste to remove noncombustibles (glass, metals). The heat contents, mass-burn combustion efficiencies, and emission factor for avoided utility electricity were all taken from EPA’s WARM documentation.[127] A relatively small benefit of 0.005 MMtCO$_2$e was estimated for 2025 (difference in emissions calculated with and without preprocessing). Implementation is assumed to begin in 2008, with ramp-up to full preprocessing of waste by 2025. The 2025 reductions would be 0.006 MMtCO$_2$e.

Table I-55. Estimated 2025 benefit for preprocessing waste for mass burn WTE plants

Mass-Burn Waste Component	2025 Tons	Energy Content (MMBtu/ ton)	Mass-Burn Combustion System Efficiency	EF for Utility-Generated Electricity (tCO$_2$/MMBtu electricity delivered)	Avoided Utility CO$_2$/ton Combusted	2025 Avoided CO$_2$ With No Preprocessing	2025 Avoided CO$_2$ With Preprocessing
Glass	72,850	–0.5	17.8%	0.282	–0.0251	–1,828	—
HDPE	10,489	37.4	17.8%	0.282	1.8773	19,692	19,692
LDPE	30,618	37.4	17.8%	0.282	1.8773	57,480	57,480
PET	105,179	19.4	17.8%	0.282	0.9738	102,423	102,423
Corrugated cardboard	163,871	14.1	17.8%	0.282	0.7078	115,982	115,982
Magazines/ third-class mail	85,771	10.5	17.8%	0.282	0.5271	45,206	45,206

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[127] *Solid Waste Management and Greenhouse Gases, A Life-Cycle Assessment of Emissions and Sinks*, EPA530-R-02-006, Washington, DC, September 2006. See http://www.epa.gov/climatechange/wycd/waste/SWMGHGreport.html#sections

Mass-Burn Waste Component	2025 Tons	Energy Content (MMBtu/ ton)	Mass-Burn Combustion System Efficiency	EF for Utility-Generated Electricity (tCO_2/MMBtu electricity delivered)	Avoided Utility CO_2/ton Combusted	2025 Avoided CO_2 With No Preprocessing	2025 Avoided CO_2 With Preprocessing
Newspaper	21,782	15.9	17.8%	0.282	0.7981	17,384	17,384
Office paper	40,163	13.6	17.8%	0.282	0.6827	27,418	27,418
Phone books	8,850	15.9	17.8%	0.282	0.7981	7,063	7,063
Text books	13,614	13.6	17.8%	0.282	0.6827	9,294	9,294
Food scraps	440,108	4.7	17.8%	0.282	0.2359	103,831	103,831
Yard trimmings	137,042	5.6	17.8%	0.282	0.2811	38,522	38,522
Mixed metals	154,666	–0.5	17.8%	0.282	–0.0251	–3,882	—
Mixed plastics	74,373	31.3	17.8%	0.282	1.5711	116,850	116,850
Mixed recyclables	609,699	10	17.8%	0.282	0.5020	306,044	306,044
Totals	**1,969,075**					**961,479**	**967,189**

MMBtu = million British thermal units; EF = emission factor; tCO_2 = tons of carbon dioxide; HDPE = high-density polyethylene; LDPE = low-density polyethylene; PET = polyethylene terephthalate; WTE = waste to energy.

There is a potential for additional GHG reductions, when the preprocessed materials are directed to recycling markets. It was unclear from the data available for this analysis whether any of the combustibles could be separated and directed to recycling. Therefore, CCS used WARM only to assess the benefit for the noncombustibles removed from the waste stream and recycled. In 2025, the additional reductions would be 0.83 $MMtCO_2e$.

For the *incremental* analysis, the GHG reductions were estimated using the 2025 results from the *stand-alone* analysis and the ratio of WTE combustion shown in Table I-54. In 2025, the incremental reductions are estimated to be 0.38 $MMtCO_2e$.

2. Costs

Cost estimates are developed for each of the policy elements below.

A. Methane Recovery From Landfilled Waste. CCS used the results of LFGTE cost modeling performed for a similar policy analysis with EPA's LFG cost model (LFGcost) to estimate the costs for this policy element.[128] Landfill methane can be used in a variety of ways for energy recovery. The three most common types of recovery projects are direct use (gas piped to a nearby facility for use in generating heat or steam), small-engine/generator sets (<800 kW), and large-engine/generator sets. These three project types were assumed to be the types that would be used for energy recovery.[129] A hypothetical LFGcost model run was performed for each of these

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[128] US EPA Landfill Methane Outreach Program, Landfill Gas Energy Cost Model (LFGcost), Version 1.4. "Summary Report, Pechan for NC GHG Mitigation Plan—Scenario 4, LFGE Project Type: Standard Reciprocating Engine-Generator Set," March 2, 2007; "Summary Report, Pechan for NC GHG Mitigation Plan—Scenario 2, No Section 45 Tax Credit LFGE Project Type: Small Engine-Generator Set," March 2, 2007; "Summary Report, Pechan for NC GHG Mitigation Plan—Scenario 1, LFGE Project Type: Direct Use (0.5 mile pipeline)," March 2, 2007.

[129] Note that this assumption represents a slight change from how the GHG offset for energy utilization benefit was estimated above (assumed all energy used for electricity generation). CCS believes that using the assumption here that some of the energy would be used for direct use (likely offsetting natural gas use) would result in negligible differences in benefits from the assumption above that all energy is used for electricity generation.

three project types with the input data shown in Table I-56. (Note that while the landfill open and closure years do not match up to the post-2020 time period for this policy, they are used to estimate methane generation rates for use within the LFGcost model, and don't affect the estimated costs in 2007 dollars.)

Table I-56. Three hypothetical landfill methane utilization options modeled

Scenario	1	2	3
Current controls	None	None	Collection and Flare
Year landfill opened	1988	1988	1983
Year landfill closed	2010	2010	2017
Annual waste acceptance rate (tons)	38,000	38,000	88,000
Landfill size (acres)	100	100	200
Technology employed	Small-engine/ generator set	Direct use (heat or steam)	Standard-engine/generator set
LFG cost value of energy produced	$0.045/kWh	$4.50/MMBtu	$0.045/kWh
Modeled costs ($/tCO$_2$e)	$2.72	–$0.82	$0.15

LFG = landfill gas; kWh = kilowatt hours; MMBtu = million British thermal units; $/tCO$_2$e = dollars per ton of carbon dioxide equivalent.

The data in Table I-57 show that the direct-use option results in a net savings (project revenues greater than costs), while the small- and standard-engine/generator set options result in net costs. Direct use is typically only cost-effective when the landfill is within a short radius to the end user (usually a half mile or less). Hence, the opportunities for direct use are limited. Standard-engine/generator set projects (≥800 kW) are used at projects with moderate-to-large methane production (1.4MMm^3/year collected on average). Small-engine/generator set projects are applicable at smaller sites.

CCS used the following assumptions on the mix of projects that would be implemented to achieve the policy's goals: 17% of methane reduced via standard-engine/generator set projects (17% of the EPA Landfill Methane Outreach Program database waste in place is at flared sites, which could be candidates for these projects); 20% of methane is controlled by direct-use projects (number of projects assumed to be limited by location of end users); and the remaining 63% is assumed to be controlled by small-engine/generator set projects. The cost data are summarized in Table I-57.

Using this blend of LFG energy projects and the LFG cost output data, a blended cost-effectiveness estimate of $1.57/tCO$_2$e was estimated (see Table I-58). This value is fairly conservative (high), in that it assumes a large fraction of the new LFG projects will be small-engine/generator set projects, which have higher costs than the other two project types. For both the *stand-alone and incremental analyses*, the blended cost-effectiveness estimate was applied to the emission reductions to be achieved at uncontrolled sites in each year by the policy to estimate costs in each year (see Table I-59).

In addition to the costs estimated above, additional costs may be incurred to increase the collection efficiencies at landfills from the current assumed 75% efficiency to at least 90%. CCS projects an estimated capital cost of $400,000 per landfill site will be needed to install additional gas wells.[130] These costs were applied to the 11 landfill sites from EPA's Landfill Methane Outreach Program (LMOP) database that are indicated to be operating in the post-2020 time frame (11 out of a total of 32 open and closed landfills in Minnesota) to represent additional costs to be incurred at flared and LFGTE sites. It was assumed that these installations occur beginning in 2015 and would be completed by 2020. To annualize the capital costs, CCS assumed a 10-year loan period and an 8% interest rate (the same assumptions used to derive the cost-effectiveness for projects installed at uncontrolled sites).

CCS did not include the effects of the Section 45 Tax Credit for production of renewable energy, since this credit may or may not be available to many of the projects that would be installed due to this policy. Inclusion of this tax credit would have a small effect on lowering the costs for the policy. For example, the cost-effectiveness for the small-engine/generator set option would decrease from the $2.72/t estimate shown above to $2.46/t.

Stand-Alone Analysis—CCS assumed that additional costs for LFG control would begin to be incurred in 2015 (i.e., some sites would need to begin installing controls to meet the 2020 goal of 90% methane collection). Table I-57 presents the calculation of NPV costs and the discounted/levelized cost-effectiveness (reductions divided by discounted costs). The NPV of $5.7 million was derived using the CCS standard 5% discount rate for the MCCAG process.

Table I-57. Stand-alone cost-effectiveness data for three landfill methane utilization options

EPA LFG Cost Modeling Data	Total Capital	Average Annual O&M	Annualized Costs	Annual Revenue	Annual Average Reductions ($MMtCO_2e$)	Project Reductions ($MMtCO_2e$)	CE ($MMtCO_2e$)
Scenario 1: Direct Use (0.5-mile pipeline)	$621,573	$105,474	$198,088	$219,870	0.024	0.36	(0.82)
Scenario 2: Small Engine	$753,365	$102,141	$214,392	$70,020	0.023	0.34	2.72
Scenario 3: Standard Engine	$2,612,674	$335,475	$724,763	$631,620	0.088	1.32	0.15

EPA = U.S. Environmental Protection Agency; LFG = landfill gas; O&M = operations and maintenance; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; CE = cost-effectiveness.

Table I-58. Blended cost-effectiveness estimate for three landfill methane utilization options

Blended Cost-Effectiveness	Assumed Methane Fraction Controlled	Fractional CE	Notes
Scenario 1: Direct Use (0.5 mile pipeline	0.20	$(0.16)	For non-LFGTE sites, 83% of LMOP waste in place is at uncontrolled sites
Scenario 2: Small Engine	0.63	$1.71	Breakout for direct use versus small engine is assumed
Scenario 3: Standard Engine	0.17	$0.03	For non-LFGTE sites, 17% of LMOP waste in place is at flared sites
		$1.57	**Blended CE estimate**

LFGTE = landfill gas to energy; LMOP = [EPA's] Landfill Methane Outreach Program; CE = cost-effectiveness.

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[130] J. Ketchum, Waste Management, personal communication with S. Roe, CCS, December 5, 2007. This is the midpoint of a range of estimated costs of $300,000–$500,000 per site.

Table I-59. Calculation of costs for methane recovery policy element (stand-alone analysis)

Year	Avoided Emissions ($MMtCO_2e$)	Annual Costs (2007$)	Discounted Costs	Cost-Effectiveness ($\$/tCO_2e$)
2008	0.00	0	0	
2009	0.00	0	0	
2010	0.00	0	0	
2011	0.00	0	0	
2012	0.00	0	0	
2013	0.00	0	0	
2014	0.00	0	0	
2015	0.07	$197,278	$140,202	
2016	0.13	$394,556	$267,051	
2017	0.20	$591,835	$381,502	
2018	0.26	$789,113	$484,447	
2019	0.33	$986,391	$576,723	
2020	0.40	$1,124,058	$625,917	
2021	0.46	$1,202,112	$637,506	
2022	0.53	$1,280,167	$646,571	
2023	0.59	$1,358,222	$653,328	
2024	0.66	$1,436,276	$657,975	
2025	0.73	$1,514,331	$660,698	
Totals	**4.4**	**$10,874,339**	**$5,731,919**	**$1**

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

Incremental Analysis—The costs for the incremental analysis were estimated in the same way as for the stand-alone analysis. The same capital costs for additional collection infrastructure at existing controlled landfill sites were used, along with the cost-effectiveness for collection and control of methane at uncontrolled sites. The results were an estimated cost-effectiveness of $2.54/t, an NPV of $3.8 million, and cumulative reductions of 1.5 $MMtCO_2e$.

B. Residuals Management. For the stand-alone costs, CCS assumed that additional WTE capacity will be needed to handle the additional organic waste to be combusted. For plants with 1,000 ton/day capacity, MPCA provided annualized cost estimates of $75–$80/ton for mass-burn plants and $120/ton for refuse-derived fuel plants.[131] CCS used the midpoint of this range ($100/ton) to estimate costs for each year of the policy, based on the additional tons directed to WTE. A summary of the cost estimates is provided in Table I-60.

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[131] J. Chiles, MPCA, personal communication with S. Roe, CCS, November, 2007.

Table I-60. Calculation of costs for organics and WTE policy element (stand-alone analysis)

Year	Avoided Emissions ($MMtCO_2e$)	Organics Directed to WTE (tons)	Annualized Costs (2007$)	Discounted Costs	Cost-Effectiveness ($\$/tCO_2e$)
2008	0.065	84,005	$8,400,510	$8,400,510	
2009	0.13	168,010	$16,801,019	$16,000,971	
2010	0.20	252,015	$25,201,529	$22,858,530	
2011	0.26	336,020	$33,602,038	$29,026,704	
2012	0.33	420,025	$42,002,548	$34,555,600	
2013	0.39	504,031	$50,403,058	$39,492,115	
2014	0.46	588,036	$58,803,567	$43,880,127	
2015	0.52	672,041	$67,204,077	$47,760,683	
2016	0.53	685,958	$68,595,847	$46,428,369	
2017	0.54	699,876	$69,987,617	$45,114,642	
2018	0.55	713,794	$71,379,387	$43,820,752	
2019	0.56	727,712	$72,771,157	$42,547,788	
2020	0.58	741,629	$74,162,927	$41,296,693	
2021	0.59	755,547	$75,554,697	$40,068,269	
2022	0.60	769,465	$76,946,468	$38,863,195	
2023	0.61	783,382	$78,338,238	$37,682,032	
2024	0.62	797,300	$79,730,008	$36,525,235	
2025	0.63	811,218	$81,121,778	$35,393,163	
Totals	**8.1**			**$649,715,377**	**$80**

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent; WTE = waste to energy; $\$/tCO_2e$ = dollars per ton of carbon dioxide equivalent.

C. WTE Preprocessing. MPCA provided an annualized cost estimate of $15–$20/ton for metal separation preprocessing at existing mass-burn plants.[132] CCS applied the midpoint of this range to the tons to be preprocessed in each year. Table I-61 provides the results of the cost analysis.

Table I-61. Cost analysis for WTE preprocessing (stand-alone analysis)

Year	Avoided Emissions ($MMtCO_2e$)	Additional WTE Preprocessing (tons)	Annualized Costs (2007$)	Discounted Costs	Cost-Effectiveness ($\$/tCO_2e$)
2008	0.046	145,857	$2,552,504	$2,552,504	
2009	0.09	291,715	$5,105,009	$4,861,913	
2010	0.14	437,572	$7,657,513	$6,945,590	
2011	0.19	583,430	$10,210,017	$8,819,797	
2012	0.23	729,287	$12,762,522	$10,499,758	
2013	0.28	875,144	$15,315,026	$11,999,723	
2014	0.32	1,021,002	$17,867,530	$13,333,026	
2015	0.37	1,166,859	$20,420,034	$14,512,137	
2016	0.42	1,312,717	$22,972,539	$15,548,718	

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[132] Ibid.

Year	Avoided Emissions ($MMtCO_2e$)	Additional WTE Preprocessing (tons)	Annualized Costs (2007$)	Discounted Costs	Cost-Effectiveness ($\$/tCO_2e$)
2017	0.46	1,458,574	$25,525,043	$16,453,670	
2018	0.51	1,604,431	$28,077,547	$17,237,178	
2019	0.56	1,750,289	$30,630,052	$17,908,757	
2020	0.60	1,896,146	$33,182,556	$18,477,289	
2021	0.65	2,042,003	$35,735,060	$18,951,065	
2022	0.70	2,187,861	$38,287,565	$19,337,822	
2023	0.74	2,333,718	$40,840,069	$19,644,771	
2024	0.79	2,479,576	$43,392,573	$19,878,638	
2025	0.84	2,625,433	$45,945,078	$20,045,685	
Totals	7.9			$257,008,043	$32

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent; WTE = waste to energy; $\$/tCO_2e$ = dollars per ton of carbon dioxide equivalent.

Key Assumptions: The analysis conducted here is tied to the analysis done for AFW-7, so all of the same key assumptions and uncertainties apply (in particular the BAU waste management forecast). Each of the cost inputs above contains key assumptions; additional study of these inputs could reduce the associated uncertainty in the cost estimates.

The analysis does not factor in the closure of specific landfills or the adoption of LFG controls at specific landfills. The modeling within WARM, as shown above and in AFW-7, was done at the state level. Modeling GHG emissions and reductions at individual sites is beyond the scope of this analysis; however, the approach used is consistent with the methods used to develop the GHG forecast for the waste management sector.

Key Uncertainties

See Key Assumptions, above—the uncertainties are driven by the assumed BAU waste management forecast under AFW-7, as well as the use of EPA's WARM.

Additional Benefits and Costs

None identified.

Feasibility Issues

The MCCAG recommends that further study be completed on detailed implementation plans and the real cost impacts on specific Minnesota business and consumer sectors and taxpayers.

An analysis is presented below of the GHG benefits that would occur if the goals of AFW-7 and AFW-8 are not achieved, and if existing MPCA goals for waste management are used instead. The future assumptions for municipal solid waste management based on these goals are as follows:[133]

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[133] Ibid., January 18, 2008.

- BAU waste generation, as shown in Table I-35, above (i.e., no source reduction);
- Recycling rates remain on a BAU track of 41% (38% conventional recycling and 3% organics reuse); and
- 30% of total waste generation is directed to WTE in 2011 (as shown in Table I-35, current BAU waste management is estimated to direct about 20% of waste generation to WTE in 2011).

An alternative waste management forecast to that shown under AFW-7 (Table I-36) is shown in Table I-62.

Table I-62. Waste management forecast based on current MPCA goals

Waste Management Under Policy Goals	2005	2010	2015	2025
MSW generation (based on 0% source reduction goals)	6,090,000	6,690,957	7,351,215	8,873,623
MSW source reduced (0%)	—	—	—	—
MSW recycled (38% rate remains constant)	2,320,290	2,549,254	2,800,813	3,380,850
Organics reuse (3% of generation remains constant)—left out of WARM	171,147	188,036	206,591	249,375
MSW disposed in landfills (after incremental recycling and composting)	2,449,928	1,783,943	1,408,640	1,389,787
Waste to energy (30% of total waste generation by 2011)	1,218,000	1,940,377	2,205,365	2,662,087
On-site disposal (2% of waste not recycled)—left out of WARM	75,394	82,834	91,008	109,855
MSW and source-separated compost (0.7%; remains constant)	26,388	334,548	845,390	1,331,043

MSW = municipal solid waste; WARM = Waste Reduction Model.

Similar modeling methods were used to estimate the benefits of this alternative waste management scenario using WARM as were used to estimate the benefits of AFW-7. The 2025 WARM modeling inputs for the alternative waste management scenario are shown in Table I-63 (for comparison to Tables 39 and 40).

Table I-63. 2025 WARM model inputs for the alternative waste management scenario

Material	Baseline Generation	Tons Source Reduced	Tons Recycled	Tons Landfilled	Tons Combusted	Tons Composted
Aluminum cans	39,904	—	39,904			N/A
Steel cans	30,980	—	30,980			N/A
Copper wire	—					N/A
Glass	272,697	—	174,069	98,628	—	N/A
HDPE	64,368	—	3,975	60,393	—	N/A
LDPE	114,277	—		114,277	—	N/A
PET	42,388	—	4,778	37,610	—	N/A
Corrugated cardboard	883,177	—	532,192	350,985		N/A
Magazines/third-class mail	191,399	—	50,558	140,841		N/A
Newspaper	323,851	—	288,082	35,769		N/A

Material	Baseline Generation	Tons Source Reduced	Tons Recycled	Tons Landfilled	Tons Combusted	Tons Composted
Office paper	125,729	—	59,780	65,949		N/A
Phone books	17,052	—	2,521	14,531		N/A
Textbooks	22,356	—		22,356		N/A
Dimensional lumber	143,694	—	143,694			N/A
Medium-density fiberboard	—					N/A
Food scraps	598,345	N/A	N/A	598,345		—
Yard trimmings	293,138	N/A	N/A	256,434		36,704
Grass	—	N/A	N/A			
Leaves	—	N/A	N/A			
Branches	—	N/A	N/A			
Mixed paper (general)	900,327	N/A	412,972	329,881	157,474	N/A
Mixed paper (residential)	—	N/A				N/A
Mixed paper (office)	—	N/A				N/A
Mixed metals	807,612	N/A	643,231	164,381		N/A
Mixed plastics	210,215	N/A	60,859	149,356		N/A
Mixed recyclables	1,243,482	N/A	898,283	—	345,199	N/A
Mixed organics	345,199	N/A	N/A	—	345,199	—
Mixed MSW	1,814,215	N/A	N/A	—	1,814,215	N/A
Carpet	243		243			N/A
Personal computers	10,240		10,240			N/A
Clay bricks	—		N/A		N/A	N/A
Concrete[1]	—	N/A			N/A	N/A
Fly ash[2]	—	N/A			N/A	N/A
Tires[3]	25,017		25,017			N/A

N/A = not applicable; HDPE = high-density polyethylene; LDPE = low-density polyethylene; PET = polyethylene terephthalate; MSW = municipal solid waste.

1 Recycled concrete is used as aggregate in the production of new concrete.

2 Recycled fly ash is utilized to displace Portland cement in concrete production.

3 Recycling tires is defined in this analysis as retreading and does not include other recycling activities (e.g. crumb rubber applications).

The 2025 WARM results for the alternative waste management scenario are shown in Table I-64 (for comparison to Table I-41).

Table I-64. 2025 WARM model results for the alternative waste management scenario

Material	Source Reduction (tons)	Incremental GHG Emissions From Source Reduction (tCO_2e)	Incremental Recycling (tons)	Incremental GHG Emissions From Recycling (tCO_2e)	Incremental Landfilling (tons)	Incremental GHG Emissions From Landfilling (tCO_2e)	Incremental Combustion (tons)	Incremental GHG Emissions From Combustion (tCO_2e)	Incremental Composting (tons)	Incremental GHG Emissions From Composting (tCO_2e)	Total Incremental GHG Emissions (tCO_2e)
Aluminum cans	0	0	0	0	0	0	0	0	N/A	N/A	0
Steel cans	0	0	0	0	0	0	0	0	N/A	N/A	0
Copper wire	0	0	0	0	0	0	0	0	N/A	N/A	0
Glass	0	0	0	0	0	0	0	0	N/A	N/A	0
HDPE	0	0	0	0	0	0	0	0	N/A	N/A	0
LDPE	0	0	0	0	0	0	0	0	N/A	N/A	0
PET	0	0	0	0	0	0	0	0	N/A	N/A	0
Corrugated cardboard	0	0	0	0	0	0	0	0	N/A	N/A	0
Magazines/third-class mail	0	0	0	0	0	0	0	0	N/A	N/A	0
Newspaper	0	0	0	0	0	0	0	0	N/A	N/A	0
Office paper	0	0	0	0	0	0	0	0	N/A	N/A	0
Phone books	0	0	0	0	0	0	0	0	N/A	N/A	0
Textbooks	0	0	0	0	0	0	0	0	N/A	N/A	0
Dimensional lumber	0	0	0	0	0	0	0	0	N/A	N/A	0
Medium-density fiberboard	0	0	0	0	0	0	0	0	N/A	N/A	0
Food scraps	N/A	N/A	N/A	N/A	0	0	0	0	0	0	0
Yard trimmings	N/A	N/A	N/A	N/A	0	0	0	0	0	0	0
Grass	N/A	N/A	N/A	N/A	0	0	0	0	0	0	0
Leaves	N/A	N/A	N/A	N/A	0	0	0	0	0	0	0
Branches	N/A	N/A	N/A	N/A	0	0	0	0	0	0	0
Mixed paper (general)	N/A	N/A	0	0	(157,474)	(54,833)	157,474	(102,684)	N/A	N/A	(157,517)
Mixed paper (residential)	N/A	N/A	0	0	0	0	0	0	N/A	N/A	0
Mixed paper (office)	N/A	N/A	0	0	0	0	0	0	N/A	N/A	0
Mixed metals	N/A	N/A	0	0	0	0	0	0	N/A	N/A	0
Mixed plastics	N/A	N/A	0	0	0	0	0	0	N/A	N/A	0

Material	Source Reduction (tons)	Incremental GHG Emissions From Source Reduction (tCO_2e)	Incremental Recycling (tons)	Incremental GHG Emissions From Recycling (tCO_2e)	Incremental Landfilling (tons)	Incremental GHG Emissions From Landfilling (tCO_2e)	Incremental Combustion (tons)	Incremental GHG Emissions From Combustion (tCO_2e)	Incremental Composting (tons)	Incremental GHG Emissions From Composting (tCO_2e)	Total Incremental GHG Emissions (tCO_2e)
Mixed recyclables	N/A	N/A	0	0	(345,199)	(48,143)	345,199	(210,113)	N/A	N/A	(258,256)
Mixed organics	N/A	N/A	N/A	N/A	(345,199)	(81,555)	345,199	(68,587)	0	0	(150,142)
Mixed MSW	N/A	N/A	N/A	N/A	0	0	0	0	N/A	N/A	0
Carpet	0	0	0	0	0	0	0	0	N/A	N/A	0
Personal computers	0	0	0	0	0	0	0	0	N/A	N/A	0
Clay bricks	0	0	N/A	N/A	0	0	N/A	N/A	N/A	N/A	0
Concrete	N/A	N/A	0	0	0	0	N/A	N/A	N/A	N/A	0
Fly ash	N/A	N/A	0	0	0	0	N/A	N/A	N/A	N/A	0
Tires	0	0	0	0	0	0	0	0	N/A	N/A	0
Total	**0**	**0**	**0**	**0**	**(847,872)**	**(184,531)**	**847,872**	**(381,383)**	**0**	**0**	**(565,915)**

GHG = greenhouse gas; $MtCO_2e$ = metric tons of CO_2 equivalent; HDPE = high-density polyethylene; LDPE = low-density polyethylene; PET = polyethylene terephthalate; MSW = municipal solid waste; WARM = Waste Reduction Model.

Table I-65 provides a comparison of the benefits of this alternative waste management scenario, based on current MPCA waste management goals to the goals of AFW-7 and AFW-8. For the costs of the alternative waste management scenario, only the costs for additional WTE capacity were included (costs for additional landfill capacity, if needed, are not included). As with the AFW-8 analysis above for WTE combustion of organics, an average annualized cost of $100/ton was used to estimate the NPV and cost effectiveness of the alternative waste management scenario. An NPV of $860 million and a cost effectiveness of $117/tCO$_2$e were estimated. These estimates compare to an estimated cost savings of –$4/tCO$_2$e for the combined AFW-7&8 CCAG recommendations. A substantial difference in 2025 and cumulative benefits was also estimated as shown below.

Table I-65. Comparison of 2025 benefits of AFW-7 and AFW-8 policy recommendations to the alternative waste management scenario

Waste Management Scenario	2025 Avoided Emissions (MMtCO$_2$e)	2008–2025 Cumulative Reductions (MMtCO$_2$e)	2008-2025 Costs/Cost Savings ($Million)	Cost-Effectiveness ($/tCO$_2$e)	Notes
AFW-7: Source Reduction, Recycling, and Composting	7.4	70	–$11	–$0.20	
AFW-8: Landfill Methane and WTE Preprocessing	0.62	5.1	$263	$51	Reflects AFW-7 Overlap
AFW-7 and AFW-8 Total	8.0	75	$120	$2	
Alternative Scenario: Current MPCA Goals	0.57	7.4	$866	$117	

MMtCO$_2$e = million metric tons of carbon dioxide equivalent; WTE = waste to energy; MPCA = Minnesota Pollution Control Agency; Negative numbers represent cost savings.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

None.

Appendix J
Cross-Cutting Issues
Policy Recommendations

Summary List of Policy Recommendations

Policy No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$)			Net Present Value 2008–2025 (Million $)	Cost-Effective-ness ($\$/MtCO_2e$)	Level of Support
		2015	2025	Total 2008-2025			
CC-1	GHG Inventories, Forecasting, Reporting, and Registry	*Not quantified*					Unanimous
CC-2	Statewide GHG Reduction Goals and Targets	*Not quantified*					Unanimous
CC-3	State and Local Government GHG Emissions (Lead by Example)	*Not quantified*					Unanimous
CC-4	Public Education and Outreach	*Not quantified*					Unanimous
CC-7	Participate in Regional and Multistate GHG Reduction Efforts	*Not quantified*					Unanimous
CC-8	Encourage the Creation of a Business-Oriented Organization To Share Information and Strategies, Recognize Successes, and Support Aggressive GHG Reduction Goals	*Not quantified*					Unanimous
CC-9	Dedicate Greater Public Investment to Climate Data and Analysis	*Not quantified*					Unanimous
	Sector Total After Adjusting for Overlaps	***Not quantified***					
	Reductions From Recent Actions	***Not quantified***					
	Sector Total Plus Recent Actions	***Not quantified***					

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $\$/MtCO_2e$ = dollars per metric ton of carbon dioxide equivalent.

NOTE: The Minnesota CC Technical Work Group notes that a number of the recommendations contained herein may entail costs to state government to implement. Resources will need to be provided to successfully carry out these initiatives.

CC-1. GHG Inventories, Forecasting, Reporting, and Registry

Policy Description

Greenhouse gas (GHG) emission inventories are essential for understanding the magnitude of all emission sources and sinks (both natural and those resulting from human activities), for estimating the relative contribution of various types of emission sources and sinks to total emissions, for informing state leaders and the public on statewide trends, and for assisting with verifying GHG reductions associated with implementation of action plan initiatives.

GHG forecasts, built on solid inventories, help to predict likely impact scenarios, identify the factors that affect trends over time, and highlight opportunities for mitigating emissions or enhancing sinks.

GHG reporting reflects the measurement and reporting of GHG emissions to support tracking and management of emissions. GHG reporting can help sources identify emission reduction opportunities and reduce risks associated with possible future GHG mandates by moving up the learning curve. Tracking and reporting of GHG emissions can also help in the construction of periodic state GHG inventories. GHG reporting is a precursor for sources to participate in GHG reduction programs, opportunities for recognition, and a GHG emission reduction registry, as well as to secure "baseline protection" (i.e., credit for early reductions).

A GHG registry enables recording of GHG emission reductions in a central repository with transaction ledger capacity to support tracking, management, and ownership of emission reductions; establish baseline protection; enable recognition opportunities; and provide a mechanism for regional, multistate, and cross-border cooperation. Properly designed registry structures also provide a foundation for possible future trading programs.

Policy Design

The state should institute formal GHG inventory and forecast and GHG reporting functions within the Minnesota Pollution Control Agency (MPCA), to be assisted by other state agencies as needed.

Goals:

- Develop a periodic, consistent, and complete inventory of emission sources and sinks at least once every 2 years. To the degree that data and methods allow, the inventory should include all natural and man-made emissions generated within the boundaries of the state (i.e., a production-based inventory approach), as well as emissions associated with energy imported and consumed in the state (i.e., a consumption-based inventory approach). Through performance metrics and differences in year-to-year emissions, the inventory should provide a way of documenting and illuminating trends in state GHG emissions.
- Develop a protocol for use in preparing the statewide emission and sink inventory. This should include a consistent protocol for evaluating the state's progress in meeting the goals

of the Next Generation Energy Act of 2007, which should logically form the basis for inventory reporting of electricity sector emissions under a consumption-based approach.

- Biennially provide a summary of statewide emission and sink trends and progress toward the goals of the 2007 Next Generation Energy Act to the legislature.
- Develop a periodic, consistent, and complete forecast of future GHG emissions in at least 5- and 10-year increments extending at least 20 years into the future. MPCA should periodically assemble the GHG forecasts, which should reflect projected growth as well as the implementation of scheduled mitigation projects. In the forecasting of future GHG emissions, the treatment of uncertainties should be transparent, should be as consistent as possible across sectors and time and, to the extent possible, should reflect multiple scenarios. The estimation methods should be consistent with those used to develop the emission inventory and should reflect best practice.
- Develop a standardized protocol for the periodic forecasting of statewide GHG emissions.

Timing: This function should be implemented as soon as possible as allowed by current funding and should be enhanced over time.

Parties Involved: All GHG emission sources and sinks (both natural and those resulting from human activities) should be included in the GHG inventory and forecast.

Other:

The state should develop GHG reporting opportunities for all sources. Mandatory reporting noted above should be required for significant sources as determined by MPCA, using common sense regarding de minimis emissions. Following are elements that MPCA may wish to consider:

- Subject to consistently rigorous quantification, the opportunity to voluntarily report GHG emissions should be open to all sources (e.g., combustion, processes, vehicles) using common sense regarding de minimis emissions. To encourage GHG mitigation activities from all quarters, reporting should not be constrained to particular sectors, sources, or approaches.
- GHG reporting requirements should be phased in by sectors as rigorous, standardized quantification protocols, base data, and tools become available and as responsible parties become clear. Mandatory reporting by significant sources as determined by MPCA should eventually be required, but entities should be allowed to report GHG emissions voluntarily before mandatory reporting applies to them. The state, municipalities, and other jurisdictions should be allowed to report emissions associated with their own activities and any programs they may implement.
- The goal should be reporting of organization-wide emissions within the state but with the greatest possible granularity to facilitate baseline protection.
- Reporting should occur annually on a calendar-year basis for all six traditional GHGs and, to the extent possible, for black carbon.

- Reporting of direct emissions[1] should be required, reporting of emissions associated with purchased power and heat[2] should be phased in, and voluntary reporting of other indirect emissions[3] should be allowed.
- Every effort should be made to maximize consistency with federal, regional, and other states' GHG reporting programs.
- GHG emissions reports should be verified through self-certification and MPCA spot-checks; to qualify for future registry purposes, reports should undergo third-party verification.
- Reporting of expected increases or decreases of emissions should be mandated.
- Project-based emissions reporting should be allowed when properly identified as such and when quantified with equally rigorous consistency.
- The reporting program should provide for appropriate public transparency of reported emissions.

The state has joined the effort to develop a national GHG registry through *The Climate Registry*. Being a charter state in this effort should help ensure that Minnesota's needs and priorities are addressed in the course of *The Climate Registry*'s development. To the extent that Minnesota's needs may not be fully met by *The Climate Registry,* the state should consider developing supplemental or ancillary registry capacity or opportunity. Elements to consider include

- Geographic applicability at least at the statewide level and as broadly (i.e., regionally or nationally) as possible.
- Allowing sources to start as far back chronologically as good data exist, as affirmed by an independent third-party verification, and allowing registration of project-based reductions that are equally rigorously quantified.
- Incorporating adequate safeguards to ensure that reductions are not double-counted by multiple registry participants; providing appropriate transparency; and allowing the state to be a valid participant for reductions associated with its programs, direct activities, or efforts.
- Striving for maximum consistency with other state, regional, and national efforts; allowing for the greatest flexibility as GHG mitigation approaches evolve; and providing guidance to assist participants.

Goals: Implementation of a GHG registry for Minnesota sources as soon as possible.

Timing: As soon as possible.

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[1] In the *GHG Protocol,* the most widely used accounting tool to quantify and manage GHGs, direct emissions are defined as "Scope 1" emissions. These are GHGs controlled by an entity, such as fuel use by a facility. See www.ghgprotocol.org/calculations-tools/service-sector

[2] Indirect emissions from the purchase of electricity, heat or steam are defined as "Scope 2" emissions in the *GHG Protocol*. www.ghgprotocol.org/calculations-tools/service-sector

[3] Indirect emissions from service sector (banks, hospitals, etc.) and office-based organizations that do not produce on-site emissions are defined as "Scope 3" emissions in the *GHG Protocol.* These include employee commuting, business travel, and transport and mobile sources. Waste water treatment emissions are also included in Scope 3.

Parties Involved: Probably overseen by MPCA; costs shared by participants benefiting from the registry.

Implementation Mechanisms

See the items above. The elements of this option are the foundation of a climate action program in Minnesota. Therefore, they will require an adequate investment of resources by the state to accomplish them. In particular, MPCA will need additional resources to implement key elements of the recommendations from this process.

Related Policies/Programs in Place

MPCA has a long-standing program in place for preparing and updating GHG emission inventories for all sectors and GHG pollutants. Governor Pawlenty has recently signed the Midwestern Regional Greenhouse Gas Reduction Accord.

Type(s) of GHG Reductions

The option is an enabling policy to encourage management, tracking and, ultimately, reduction of GHG emissions. It does not reduce GHG emissions itself per se.

Estimated GHG Reductions and Net Costs or Cost Savings

This option could be considered an administrative and enabling function of the MN Climate Action Plan (including enabling any future cap-and-trade options) and will incur overhead costs but will not directly reduce emissions per se except where these data motivate reductions for public relations by individual companies or sources.

The reporting and registry components of this policy option would help position Minnesota entities for participation in an emissions trading program, should one develop in the future, leading to cost savings. Although establishment of a credible reporting and registry program is essential for participating in a trading program, these elements do not reduce GHG emissions themselves.

Data Sources: Many.

Quantification Methods: Several methods will be designed to follow standard, comparative, and accepted approaches that allow the exchange/sale of emission credits, should this become a need in Minnesota.

Key Assumptions: Reporting will establish a baseline for GHG emissions and will provide a monitoring tool for assessing the efficacy of the Climate Action Plan. Adjustments will be made in the plan as certain techniques prove more or less beneficial than projected. Downward trends will allow for further incentives to be developed for sectors that show continuous improvement. Effective emission sinks can be identified and augmented. Public participation will inform and involve citizens in the overall goal of GHG emission reductions. Forecasting will allow state officials to plan for, implement, and monitor necessary additions of emission sources or sinks to the emission cycle.

Key Uncertainties

Many uncertainties are associated with maintaining an inventory of the many natural sources of GHG emissions:

- How will potential requirements eventually emanating from a federal GHG reduction program affect the Minnesota climate programs?
- Will political leadership ensure the adequacy and timeliness of resources to implement this option?

Additional uncertainties will most likely arise as implementation proceeds.

Additional Benefits and Costs

See above.

Feasibility Issues

None cited at this time. The state will need to ensure the accuracy of out-of-state GHG production inventories and to avoid double-counting of GHG emissions in registries. The state will need to be clear about the distinction between its projections and forecasting functions.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

CC-2. Statewide GHG Reduction Goals and Targets

Policy Description

Article 5 of the Next Generation Energy Act of 2007 (S.F. No. 145) establishes goals for Minnesota to reduce statewide GHG emissions across all sectors producing those emissions, to levels at least 15% below 2005 levels by 2015, at least 30% below 2005 levels by 2025, and at least 80% below 2005 levels by 2050. The levels will be reviewed based on the MN Climate Action Plan. In addition, Article 1 of the act establishes that Minnesota's energy policy requires that (1) the per capita use of fossil fuel as an energy input be reduced by 15% by 2015, through increased reliance on energy efficiency and renewable energy alternatives; and (2) 25% of the total energy used in the state be derived from renewable energy resources by 2025.

Policy Design

Established in the Next Generation Energy Act of 2007.

Goals: As noted above. Periodic updates may be needed.

Timing: As soon as possible.

Parties Involved: State government, municipalities, citizens' groups, nongovernmental organizations, and commercial, industrial, economic, and educational sectors.

Implementation Mechanisms

The policy option descriptions from the individual Technical Work Groups (TWGs) suggest specific implementation mechanisms. Many are regulatory, requiring executive action or further legislation. However, the very scale associated with comprehensively addressing climate change suggests that there are essential nonregulatory aspects to implementation as well, such as education and engagement of the general public, municipalities, and the commercial, industrial, economic, and educational sectors in the state at many levels (as discussed further in CC-4).

In all sectors, improvements in energy efficiency directly reduce fuel costs, giving payback on investment to the user. However, funding the up-front costs of efficiency measures is likely to require a diverse range of innovative funding mechanisms and incentives to ensure sufficiently rapid penetration of the market to achieve the year 2025 goal of a 30% reduction in GHG emissions from the state.

Related Policies/Programs in Place

GHG emission reduction goals have been established by Governor Pawlenty and the Minnesota Legislature. The Governor has recently signed the Midwestern Regional Greenhouse Gas Reduction Accord.

Type(s) of GHG Reductions

All.

Estimated GHG Reductions and Net Costs or Cost Savings

Not applicable.

Key Uncertainties

Projected data uncertainties associated with 2050 forecasts.

Additional Benefits and Costs

Not applicable.

Feasibility Issues

Not applicable.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

CC-3. State and Local Government GHG Emissions (Lead by Example)

Policy Description

In many areas, the Minnesota state government is already leading by example to obtain GHG emission reductions. State and local governments are responsible for providing a multitude of services for the public that are delivered through very diverse operations and result in wide-ranging GHG emission activities. State and local governments can take the lead in demonstrating that reductions in GHG emissions can be achieved through analysis of current operations, identification of significant GHG sources, and implementation of changes in technology, procedures, behavior, operations, and services provided. State and local governments can also encourage and provide incentives for reducing GHG emissions by others in a variety of ways.

The support of broad-ranging goals for GHG reductions for state government through the goals established below and those that already exist through the Interagency Pollution Prevention Advisory Team (IPPAT) will be helpful for setting an example and building expectations, with actual reductions realized at the state agency level. Disaggregating the state’s own GHG emissions to the agency level and showing the results in the annual IPPAT report on GHG reduction progress is an effective way to measure and manage the state’s emissions. A multiagency group oversees the ongoing climate efforts of state agencies, providing direction, guidance, resources, shared approaches, and recognition to agencies and employees working to reduce the state’s GHG emissions.

Policy Design

State and local governments should establish reduction targets for their own GHG emissions. The establishment of broad-ranging goals for reducing governments’ GHG emissions will be helpful both in setting an example and in building expectations. Because actual reductions will typically be realized at the individual agency level, disaggregating individual governments’ GHG emissions to the agency or department level and requiring annual agency- or department-specific reports on GHG reduction progress can be effective ways to measure and manage each agency’s progress toward reducing its emissions. Government agencies or departments first developed agency- or department-specific GHG emissions inventory data. These data became the baseline data for ongoing emission reduction activities and measurements, which are summarized in annual IPPAT reports by each agency or department. IPPAT oversees the ongoing climate efforts of the state government’s agencies and departments; reviews their performance; and provides direction, guidance, resources, shared approaches, and recognition to agencies or departments and their employees who are working to reduce the state government’s GHG emissions.

Goals:

- Each state agency will, in consideration of its current and projected building stock,
    - Determine and quantify its current and projected energy consumption and associated GHG emissions from such consumption.

    - Develop and propose a plan to reduce the statewide GHG emissions associated with its building stock commensurate with its pro rata share of the statewide GHG reduction goals established in the 2007 Next Generation Energy Act.
    - Provide the plan to IPPAT.
    - Report annually to IPPAT on its progress toward its GHG reduction goals in buildings.
- Each state agency will, in consideration of its current and projected transportation stock,
    - Quantify and establish the same goals for its transportation stock described above for its building stock.
    - Provide the plan to IPPAT.
    - Report annually to IPPAT on its progress toward its GHG reduction goals in transportation.

The state should develop appropriate guidelines and tools for utilizing the environmental impact assessment processes to assess and promote reductions of GHG emissions. Environmental Assessment Worksheets (EAWs) and Environmental Impact Statements (EISs) are written analyses of the potential environmental impacts of a proposed action or project in Minnesota. Including consideration of GHG emissions as part of EAW and EIS processes and documents would enable comparison of reference case GHG emission levels to future GHG emission levels as a result of proposed projects. Such information could be helpful in targeting development decisions that minimize GHG emissions or in pointing out the need for authority to regulate GHG emissions. Agencies should utilize state-developed guidelines and tools in EAW and EIS documents comparing reference case and estimated future GHG emissions. This information will guide officials and developers in choosing technologies and activities that result in development that protects the environment and reduces additional contributions of GHGs.

Additionally, the existing directives of IPPAT, along with the following Executive Orders, should be continued and enhanced:

04-02, Providing Direction to State Agencies Regarding State Contracting Procedures

04-08, Providing for State Departments To Take Actions To Reduce Air Pollution in Daily Operations (Clean Air Minnesota provisions)

04-10, Providing for State Departments To Improve Fleet and Travel Management

05-16, Providing for Energy Conservation Measures for State-Owned Buildings

06-03, Requiring State Agencies To Increase the Use of Renewable Fuels

Timing: The state’s efforts to lead by example in reducing its own GHG emissions have already begun through IPPAT’s actions and the above-listed Executive Orders. The baseline information and emission reductions from the prior years are already recorded. Future annual reports should show further progress in reducing agency GHG emissions.

Parties Involved: Coverage should include all operations of all state agencies and all departments of local governments.

Implementation Mechanisms

- Public education and outreach to state and local government agencies and employees.
- Performance reviews and recognition of agency progress.
- Procurement of low-GHG products.
- Quantifiable, sustainable, and measurable building energy conservation improvements corresponding to the agency's pro rata share of the 1.5%/year energy conservation goal established in the 2007 Next Generation Energy Act.
- Transportation energy conservation improvements sufficient to accomplish the GHG reduction goals established in the Goals section, above.

Related Policies/Programs in Place

Descriptions follow regarding programs of these entities: the Metropolitan Council, the cities of Minneapolis and St. Paul, and 24 other member cities in the U.S. Mayors Climate Protection Agreement, through ICLEI (Local Governments for Sustainability [formerly International Council for Local Environmental Initiatives]), the Minnesota Department of Commerce (MDOC), energy efficiency (EE) and conservation improvement programs (CIPs), MPCA Sustainability Conference information, and Explore Minnesota. The Governor has recently signed the Midwestern Regional Greenhouse Gas Reduction Accord.

Type(s) of GHG Reductions

Steps to reduce energy demand would reduce all GHGs related to energy production. Support for renewable energy and cleaner energy will also help lower all GHGs associated with energy production. Improving existing recycling efforts would result in an associated reduction in GHG emissions from processing new materials. Transportation and fleet management would lower vehicle emissions, as would converting vehicle fleets to run on alternative fuels (e.g., biofuels).

Estimated GHG Reductions and Net Costs or Cost Savings

Not applicable.

Key Uncertainties

Substantial uncertainty surrounds future growth rates in GHG emissions, particularly beyond 2020, as well as the timing and scope of implementation of the Minnesota Climate Change Advisory Group's (MCCAG's) recommendations for specific policy options, including those associated with the state's own GHG emissions. The state will also need to determine to what types of projects the GHG emissions analysis should be applied as part of EAW or EIS processes.

Additional Benefits and Costs

These recommendations require development of credible guidelines and tools that will result in additional costs to project sponsors and appropriate state and local agencies.

Feasibility Issues

Developing an agreed-upon framework in the beginning will be important, to ensure a cost-efficient procedure for collecting data.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

CC-4. Public Education and Outreach

Policy Description

Explicitly articulated public education and outreach can support GHG emission reduction efforts at all levels in the context of emission reduction programs, policies, or goals by fostering a broad awareness of climate change issues and effects (including co-benefits, such as clean air and public health), and engaging citizens, businesses, and institutions in actions to reduce GHG emissions. Public education and outreach efforts should integrate with and build upon existing outreach efforts involving climate change and related issues in the state and should make the public aware of GHG emissions associated with products produced outside of Minnesota and the United States. Ultimately, public education and outreach will be the foundation for the long-term success of the policy actions proposed by the MCCAG as well as those that may evolve in the future.

Policy Design

The state should build upon current educational efforts and action campaigns of state agencies, utilities, and nonprofit organizations that understand each other's offerings and should use these enhanced resources to educate and encourage all sectors within Minnesota—such as residential, commercial, and educational—to take action.

State Education Initiatives

Minnesota has a long history of environmental education. The state should work through existing organizations by encouraging them to incorporate education about climate change and the role of GHG emissions into their existing educational efforts. The states initiatives should focus on being the primary mechanism for providing mitigation, awareness, and understanding of climate change and the role humans play in causing it.

Current Efforts

Environmental Education Advisory Board

Minnesota's Environmental Education Advisory Board (EEAB) was created by the 1990 Environmental Education Act (M.S. 1998, Chap. 115A.072) to promote environmental literacy for all Minnesota citizens. EEAB advises the Governor through MPCA, state agencies, organizations, and citizens. A major vehicle is the implementation of *A GreenPrint for Minnesota: State Plan for Environmental Education.* The third edition of the *GreenPrint,* which is being revised, will list four or five main objectives for the state.

EEAB consists of 20 members—11 citizen representatives and 9 government agency representatives. One citizen member from each of the 8 congressional districts and 3 citizen at-large members comprise the citizen members (2 of the citizen members must be classroom teachers). They serve 2-year terms. EEAB also has a representative from each of the following: MPCA, Department of Education, Department of Agriculture, Department of Health, Department of Natural Resources, Board of Water and Soil Resources, Environmental Quality Board, Board of Teaching, and the University of Minnesota Extension Service.

Environmental Learning in Minnesota Fund

The Environmental Learning in Minnesota Fund is a current EEAB initiative to develop a fund to provide fiscal resources for environmental education in Minnesota. The fund would enable schools, environmental learning centers, residential environmental learning centers, science museums, colleges and universities, and various local government entities to educate Minnesota citizens and businesses about critical issues in the global warming discussion. While this effort is still in the exploratory stage, EEAB is currently discussing with the Minnesota Association for Environmental Education the potential for a public–private partnership to manage and administer the fund. Although the details of this initiative are still fluid, revolving funding priorities and joint administration are expected be part of the final program.

Minnesota Scope and Sequence

Environmental Literacy Scope and Sequence (March 2002, also due for revision in 2008) is designed to help create opportunities for mainstreaming environmental education in a way that has not been possible before. It provides a systems approach to environmental education that can focus the efforts of teachers and other educators to unify their many independent efforts to achieve the goal of environmental literacy. Because the *Scope and Sequence* is based on both state and national standards, it enables environmental educators to build, adapt, or integrate curricula and assessments that are most appropriate for their particular grade level or audience.

Sharing Environmental Education Knowledge Partnership

Sharing Environmental Education Knowledge (SEEK) is a partnership of more than 130 organizations that provide environmental education to Minnesota citizens. The partnership's main communication tool is a Web site (www.seek.state.mn.us) that includes a resource directory with more than 1,500 resources, a news area, jobs and internship information, training opportunities, a calendar of statewide activities (for the public and for educators,) regional pages, and other information areas. SEEK members are nonprofit and for-profit businesses and municipal, state, and federal government entities.

Utility Programs

Utility CIPs should be strengthened to provide education about specific, direct actions consumers can take to reduce their energy use and emissions.

Nonprofit Organizations

Minnesota nonprofit organizations, such as the Will Steger Foundation, Fresh Energy, Sierra Club, and Center for Energy and Environment (CEE), have been promoting education and action on climate change for many years. CEE has developed the Minnesota Energy Challenge as a way for people to form partnerships and take action about climate change. The Minnesota Environmental Initiative has supported a number of conferences on energy and the environment and also provides environmental education in conjunction with the Hamline University Center for Global Environmental Education. The state should not duplicate these initiatives.

Goals: The overarching goal is to raise awareness about global warming and promote individual action to reduce the Minnesota's overall GHG emissions.

Timing: Public education and outreach efforts should commence now.

Parties Involved: Rather than create a new agency, the legislature should include MDOC as a member of the EEAB and also include GHG education as part of the EEAB mission because EEAB membership is prescribed by statute language and the addition of MDOC would require legislation. This addition would ensure that any energy-related education assisted or initiated by MDOC is represented in a cohesive, coordinated manner and is supported by the state plan for environmental education, the *GreenPrint*. The MDOC should ensure that utility CIPs include effective energy education and are designed to complement the activities of nonprofit organizations. Additionally, counties may want to consider including educational initiatives about global warming as part of their Select Committee on Recycling and the Environment (SCORE)-funded programs.

Implementation Mechanisms

See above.

Related Policies/Programs in Place

See above.

Type(s) of GHG Reductions

Not applicable.

Estimated GHG Reductions and Net Costs or Cost Savings

Not applicable.

Key Uncertainties

These initiatives are designed to support implementation of other options, but their impacts are difficult to measure.

Additional Benefits and Costs

Not quantifiable at this time.

Feasibility Issues

Distinguishing between GHG education initiatives and GHG reduction policies/programs will be important.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

CC-7. Participate in Regional and Multistate GHG Reduction Efforts

Policy Description

Regional approaches undertaken in collaboration with partner states or other organizations can offer broader and more economically efficient opportunities to reduce GHG emissions across Minnesota's economy. Several options for regional, market-based GHG reduction strategies should be considered in Minnesota, such as joining the Western Climate Initiative or the Northeast States Regional Greenhouse Gas Initiative, instituting a new midwestern states GHG initiative, considering the California vehicle standards, and cost-sharing on multistate initiatives.

Policy Design

Goals: Ensure the cost-effective reduction of GHG emissions to at least the reduction levels set forth in Minnesota statute, in a manner that maximizes public benefits and induces innovation in energy efficiency and sustainable energy technologies and avoids inequitable impacts.

Timing: By February 1, 2008, the Administration must report to the state legislature on its investigation into regional GHG reduction opportunities. By August 1, 2009, Minnesota should either join an existing GHG reduction initiative or institute and join a new midwestern states GHG initiative that will ensure that Minnesota achieves the goal stated above.

Parties Involved: The Governor and his staff should implement the legislative directive (see below) and inform the chairs and ranking minority members of the legislative committees with jurisdiction over energy and environmental finance and policy.

Implementation Mechanisms

Next Generation Energy Act, S.F. No. 145, Article 5, Sec. 2, Subd. 6 (Regional activities). To the extent possible, Minnesota must, with other states in the Midwest, develop and implement a regional approach to reducing GHG emissions from activities in the region, including consulting on a regional cap-and-trade system.

Related Policies/Programs in Place

Next Generation Energy Act, S.F. No. 145, Article 5, Sec. 2, Subd. 6 (Regional activities). See above. Governor Pawlenty has recently signed the Midwestern Regional Greenhouse Gas Reduction Accord and the Midwestern Energy Security and Climate Stewardship Platform.

Type(s) of GHG Reductions

Not applicable.

Estimated GHG Reductions and Net Costs or Cost Savings

Not applicable.

Key Uncertainties

Joining another regional entity should not compromise the achievement of Minnesota's goal.

Additional Benefits and Costs

There will be additional environmental and economic co-benefits associated with the state's participation in a regional GHG emission reduction initiative that meets Minnesota's goals, including the opportunity to reduce GHG emissions in an economically efficient manner, the identification of additional areas for cooperation within specific sectors (e.g., transportation), and the reduction of other non-GHG pollutants associated with the production and use of energy.

Feasibility Issues

None cited at this time.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

CC-8. Encourage the Creation of a Business-Oriented Organization To Share Information and Strategies, Recognize Successes, and Support Aggressive GHG Reduction Goals

Policy Description

Successful state GHG reduction efforts are highly dependent on the active participation of the business community, particularly in the energy, agriculture, transportation, development, and manufacturing sectors. In Minnesota, there are many progressive corporations that are eager to participate in broad-scale efforts to reduce GHG emissions. To facilitate a strategic approach that has a significant impact, a statewide proactive business organization should be formed to promote energy efficiency and GHG reduction opportunities.

Policy Design

Goals: The Next Generation Energy Act of 2007 established general goals for GHG emission reductions and an aggressive specific annual goal of reducing energy consumption by 1.5%. A new business strategy that aggressively promotes options to improve energy efficiency by Minnesota’s businesses will help achieve these goals.

Timing: As soon as possible.

Parties Involved: The Minnesota Chamber of Commerce (Chamber), energy utilities, MDOC, energy conservation experts, and individual businesses across the state.

Implementation Mechanisms

In 1993, the Chamber created a business waste reduction program called Minnesota Waste Wise. Since then, hundreds of businesses have participated to reduce waste generation and improve recycling and reuse rates. The Chamber is now using the Waste Wise model for a new energy conservation and efficiency program that will promote the use of energy utility CIPs through education and outreach, technical assistance, and recognition programs. The Chamber is consulting with energy utilities, business consumers, and MDOC on program development. Funding will be sought from MDOC CIP grant funds.

Related Policies/Programs in Place

Energy utilities’ CIPs, Minnesota Waste Wise, ENERGY STAR.

Type(s) of GHG Reductions

CO_2 and other GHGs.

Estimated GHG Reductions and Net Costs or Cost Savings

Not applicable.

Key Uncertainties

Must secure funding.

Additional Benefits and Costs

Not quantifiable at this time.

Feasibility Issues

None identified at this time.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

CC-9. Dedicate Greater Public Investment to Climate Data and Analysis

Policy Description

To calibrate GHG mitigation policies, it is critical that decision makers and Minnesota citizens understand how climate change is currently affecting and will in the future affect the state's natural resources and economy. Much of the data and information needed to make such an assessment is being collected by various departments and entities in the state. MPCA and the Minnesota Departments of Natural Resources, Agriculture, and Employment and Economic Development should assess and identify the gaps in ongoing data collection that would need to be filled to monitor, track, and assess climate change impacts in Minnesota. The departments should develop recommendations for filling these data gaps and suggest the best approach (possibly by coordinating with the University of Minnesota) for periodically assessing how intensely Minnesota is being and is likely to be affected by climate change.

Policy Design

Goals: Develop a plan for periodically assessing the recent and projected impacts of climate change on Minnesota natural resources and economic activity. The assessment would focus on (but not be limited to) impacts on water resources and quality, air quality, landscape change, forest resources and health, ecosystem health, species diversity, fish and wildlife and their habitats, agricultural productivity, recreation and other amenities, human disease, and settlement. The assessment should treat impacts arising from climate change in the present and recent past and impacts that are likely or possible 30–50 years into the future and should rely on the best available regional climate data and assessments.

Timing: The recommendations should be developed for submittal to the state legislature by January 2009.

Parties Involved: MPCA and the Minnesota Departments of Natural Resources, Agriculture, and Employment and Economic Development; other state agencies; federal land managers; and academic researchers at public and private universities and colleges in Minnesota.

Implementation Mechanisms

An appropriate process needs to be developed that includes stakeholder participation.

Related Policies/Programs in Place

See above.

Type(s) of GHG Reductions

Not applicable.

Estimated GHG Reductions and Net Costs or Cost Savings

Not applicable.

Key Uncertainties

Adequacy of funding.

Additional Benefits and Costs

Not quantifiable at this time.

Feasibility Issues

None cited at this time.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

Appendix K
Cap-and-Trade Policy Recommendations

Summary List of Priorities for Analysis

Policy No.	Policy Recommendation	GHG Reductions (MMtCO$_2$e)			Net Present Value (Million $)	Cost-Effectiveness* ($/tCO$_2$e) 2025	Permit Price† ($/tCO$_2$e) 2025	Level of Support
		2015	2025	Total (2008–2025)				
C&T-1	Cap-and-Trade Program							Majority (9 objections)
	MGA Partners C&T *—with both RES/CIP in the baseline*		52.94			$2.65	$45.95	
	MGA Partners C&T *—no RES/CIP in the baseline*		79.82			–$12.17	$48.45	
	MGA Partners C&T *—with only RES in the baseline*		67.35			–$15.42	$46.64	
	MGA Partners+Observers C&T *—no RES/CIP in the baseline*		81.97			–$10.52	$52.44	
	MGA Partners+Observers C&T *—with both RES/CIP in the baseline*		55.45			$4.71	$50.72	
	MGA Partners+Observers C&T *—with only RES in the baseline*		69.45			–$13.48	$51.27	
	MGA plus WCI Partners C&T *—no RES/CIP in the baseline*		72.64			–$17.52	$35.69	
	MGA plus WCI Partners C&T *—with both RES/CIP in the baseline*		46.93			–$2.19	$34.95	
	MGA plus WCI Partners C&T *—with only RES in the baseline*		61.92			–$20.36	$35.07	
	MGA and WCI Partners+Observers C&T *—no RES/CIP in the baseline*		76.17			–$14.92	$41.87	
	MGA and WCI Partners+Observers C&T *—with both RES/CIP in the baseline*		50.41			$0.59	$41.25	
	MGA and WCI Partners+Observers C&T *—with only RES in the baseline*		64.92			–$17.65	$41.39	
C&T-2	Minnesota-Only C&T *—no RES/CIP in the baseline*()		89.18			–$2.39	$65.48	Merged into C&T-1
C&T-3	National C&T	*Not quantified*						Merged into C&T-1
C&T-5	Market Advisory Group (Formerly CC-11)	*Not quantified*						Unanimous
C&T-6	Regional and Multistate GHG Reduction Efforts (Formerly CC-7)	*Not quantified*						Unanimous

GHG = greenhouse gas; MMtCO$_2$e = million metric tons of carbon dioxide equivalent; $/tCO$_2$e = dollars per metric ton of CO$_2$e; MGA = Midwestern Governors Association; C&T = cap-and-trade; RES = renewable electricity standard; CIP = conservation improvement program; WCI = Western Climate Initiative; CC = Cost-Cutting Issues; Negative numbers represent cost savings.

MGA C&T partners include Illinois, Iowa, Kansas, Michigan, Minnesota, Wisconsin, and Manitoba; MGA C&T observers include Indiana, Ohio, and South Dakota; WCI partners include Arizona, California, New Mexico, Oregon, Utah, Washington, British Columbia, and Manitoba; WCI observers include Colorado, Idaho, Montana, Nevada, and Wyoming. To run simulations including both MGA and WCI states in 2025, the C&T Technical Work Group (TWG) used 2020 marginal cost curves for WCI states for 2025. The emission cap for both MGA and WCI states (or provinces) is assumed to be 30% below the 2005 level in 2025.

* This represents the average cost per metric ton of carbon dioxide equivalent (tCO$_2$e) mitigated/sequestered for Minnesota.

† This represents the marginal cost of the last tCO$_2$e mitigated/sequestered, and applies to all states involved in a trading arrangement.

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

C&T-1. Cap-and-Trade Program

Policy Description

The Minnesota Climate Change Advisory Group (MCCAG) recommends that the state of Minnesota work with its Midwestern Governors Association (MGA) partners to design and implement a multi-sector regional cap-and-trade greenhouse gas (GHG) emission trading program with the features recommended herein.

Cap-and-trade programs limit emissions by first placing a "cap," or limit, on the total number of tons of pollutants that will be permitted to be released from regulated, or "covered," sources of GHG emissions within a specified geographic area and interval of time. The cap is enforced by the issuance of permits, or "allowances," which must be surrendered by each covered source in an amount equal to its emissions. By setting the total number of allowances equal to the overall cap, total emissions are limited. Moreover, the number of allowances issued over time can be decreased, thereby further reducing total emissions.

Since the government regulates only the total emissions, the means by which the reductions are achieved is left to the individual covered sources (although many reduction activities may be covered by other policies). Sources would individually identify their least-cost options, but creating a market gives these allowances a financial value, which encourages the covered sources to collectively implement the least-cost measures at different levels of mitigation to achieve the capped emission reductions. Through trading, participants with lower costs of compliance can choose to over comply and sell their additional reductions to participants for whom compliance costs are higher. In this fashion, the overall costs of compliance are lower than they would otherwise be.

It should be noted that the least-cost approach for some sectors or sources may not be cap-and-trade; it may instead be for technology-forcing or incentive policies that address specific market barriers. A cap-and-trade program will not necessarily remove market barriers or lead to the fastest or broadest adoption of new technologies and practices that save money or stimulate economic performance.

Policy Design

To assist in the evaluation of policy options, the Cap-and-Trade (C&T) Technical Work Group (TWG) created the following principles and guidelines, which are listed in no particular order. The cap-and-trade program

- Must be cost-effective, that is, it must meet GHG reduction targets at a cost comparable to or better than alternative measures;
- Should be open to consideration of other (non–cap-and-trade) measures;
- Should encourage collective actions;
- Should be transparent;

- Should offer covered entities a degree of certainty regarding outcomes;
- Should strive for full coverage of participants;
- Should be fair in the distribution of allowances;
- Should strive for simplicity;
- Should be enforceable;
- Should be administratively efficient; and
- Should reward early actions.

Emission Reduction Goals: The law requires the MCCAG to "recommend the parameters of a cap-and-trade system that includes a cap that would prevent significant increases in greenhouse gas (GHG) emissions above current levels with a schedule for lowering the cap periodically to achieve the goals in subdivision 1 and interim goals recommended under paragraph (a)" (Minn. Stat. 216H.02, subd. 5(b)). Accordingly, the cap-and-trade program should set an initial cap at 2007 emission levels, with gradual annual reductions to achieve the statutory goals of at least 15% below 2005 levels by 2015, 30% below 2005 levels by 2025, and 80% below 2005 levels by 2050. (The cap may need to be adjusted from these levels to compensate for emissions from non-covered sectors, if projections show those sectors are likely to fall short of or exceed the target reductions.)

Timing: The cap-and-trade program should be implemented as soon as possible to prevent significant increases above current emissions in the meantime and to maximize the time available to meet the 2015 target. In the event that good historical emissions data are available from some but not all covered sectors, a phased approach can be used, or other policies can be used to address these other sectors and sources of GHG emissions.

In phased approaches, traditionally regulated stationary sources with good emissions data are included in the first phase of the program, which also includes mandatory reporting from sources planned to be covered in future phases. This allows a relatively quick program start and a ramp-up of the administrative, governance, and financial functions of the program. It also achieves greater progress in reducing emissions over time by capping a limited number of large sources early.

Complementary policies play a critical role by reducing the level of emissions that need to be covered by a cap-and-trade program and by reducing emissions directly (e.g., appliance efficiency standards and vehicle efficiency standards). In the process, they can also reduce the costs of cap-and-trade compliance by encouraging low-cost emission reductions through removal of non-price or price barriers to energy efficiency, renewable energy technologies, and other actions. Cap-and-trade programs are typically considered a means of ensuring full attainment of sector-based or economy-wide caps on emissions, or as an enhanced method of providing flexibility to compliance.

The feasibility of specific program start dates has not been closely examined here. The MCCAG recommends further study of the cap-and-trade option at the state level and regionally through the MGA initiative. Program timing will need to be examined by both groups. The MCCAG encourages an early program start for first-phase sources, such as 2010, to allow time for emitters and regulators to prepare for the program and still allow 5 years under the program to achieve reductions toward the 2015 goal.

Other Key Design Variables

Geographic Coverage: The MCCAG recommends that the geographic scope of the program be, at a minimum, Midwest regional, including the partners in the MGA initiative (Minnesota, Wisconsin, Illinois, Kansas, Iowa, Michigan, and Manitoba). The MCCAG further recommends that linkages with other regional programs such as the Western Climate Initiative (WCI) and the Northeast States Regional Greenhouse Gas Initiative (RGGI) be encouraged and that interregional program mergers be studied.

The MCCAG does not recommend the creation of a Minnesota-only cap-and-trade program. Modeling has confirmed that as a general rule, larger programs broaden access to lower-cost emission reduction opportunities, thereby reducing the overall cost of achieving the targeted reductions. The MCCAG has found that Minnesota can achieve its GHG cap-and-trade reduction goals at a lower cost through a midwest regional approach than as a single state. The MCCAG also sees other benefits from taking regional action, including significantly greater overall emission reductions, a more powerful voice during deliberations on a potential national program, and an early opportunity to work out these complex issues in a manner that is most supportive of the special needs of the Midwest prior to the implementation of a federal program. However, the MCCAG has also found that the implementation of a national program could be far preferable to a state or regional program. The Minnesota goal should be to work fervently toward the quick passage of an appropriate national program that would assimilate the regional effort.

The C&T TWG studied a Minnesota-only program, consistent with the requirements of subd. 5(b) of Minn. Stat. 216H.02. Modeling indicates that the cost of carbon dioxide (CO_2) emission reductions sufficient to meet the state goals across all economic sectors under a Minnesota-only cap-and-trade program in 2025 compares unfavorably with all regional programs studied.

Sectors and Sources Covered: The MCCAG recommends that the electric power sector, large industrial boilers and processes, transportation fuels, and landfills be included in the cap-and-trade program. The MCCAG also recommends that the program include municipal waste incinerators, large confined animal feeding operations, and other large agricultural operations where it is practical to measure emissions beyond some de minimis level. The MCCAG also favors the inclusion of fossil fuel for residential and commercial use; however, some MCCAG members disagree with the inclusion of natural gas used in residences and small commercial buildings. Supporters of the policy generally believe that there are emission reduction opportunities within this sector that could be realized through the price signals associated with cap-and-trade inclusion. Supporters also generally subscribe to the view that the cap-and-trade program as a whole benefits from broad inclusion of a large number of sectors and sources, thereby maximizing the number of low-cost emission reduction opportunities and the resources available to achieve them. Dissenters generally believe that while there remain energy efficiency opportunities within the sector, non–cap-and-trade measures are more effective at achieving those reductions. They also argue that these customers have very limited alternative fuel options that offer lower carbon emissions than natural gas. They believe inclusion would create significant additional costs for small natural gas customers without a corresponding reduction in GHG emissions.

Information provided by the Minnesota Pollution Control Agency (MPCA) indicates that the 700 currently regulated stationary sources in the power generation, industrial, and commercial sectors release approximately 54 million tons of carbon dioxide annually. Within these sectors, the electric power (41.5 million tons) and industrial (11 million tons) sectors are by far the largest contributors. But across all three sectors, the largest 10% of all sources—70 facilities—release approximately 95% of the total emissions. The annual emissions threshold above which these 70 facilities operate is 44,000 tons per year. If fossil fuels are part of the program, the remaining 630 regulated sources and all unregulated sources would also be included indirectly.

A cap-and-trade program that limits and reduces emissions from the recommended sectors could make substantial progress toward achieving the state's goal. In addition, the scope of coverage of a cap-and-trade program is substantially affected by the level of existing and future policies and measures using other mechanisms. It also will be affected by numerous interactions of design feasibility and performance (see later discussion under "Integration with Complementary Policies and Measures").

Pollutants Covered: The MCCAG recommends that the cap-and-trade program include emissions from all six GHGs listed in the statute—CO_2, methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—from the covered sectors. Most attention in other cap-and-trade programs has been focused on CO_2, which represents 84% of all GHG emissions in the United States that result from human activities. Of this, all but 2% is released as a direct result of the combustion of coal, petroleum, and natural gas. Other gases, such as methane, tend to be sector-specific. Landfills and agricultural operations release significant quantities of methane, which ton-for-ton is 21 times as powerful a GHG as CO_2 over a 100-year time span. Much work has been done to standardize the greenhouse effect forcing potential of the major gases so it is possible to regulate more than one gas under the same cap-and-trade program.

Flexibility and Cost Containment Mechanisms

- *Early-Action Incentives*—The MCCAG recommends that the cap-and-trade program include incentives to encourage "early actions," or GHG-reduction investments within capped sectors prior to the start of the program. Qualifying early-action projects should be subject to stringent standards to ensure their environmental integrity. They must be real, surplus (additional), verifiable, permanent, and enforceable. The MCCAG agrees that qualifying early actions must post-date a baseline year; however, there was no agreement on the specific year to use. Some members advocated 1990, while others preferred 2005. The C&T TWG did not have sufficient time to thoroughly study specifics of potential incentives; as a result, it is offering no recommendation on whether the early-action "incentive" should be allowed to increase the emissions cap.

- *Offsets*—The MCCAG makes no recommendation on the issue of offsets. Offsets are out-of-sector emission reduction or carbon sequestration projects that are recognized by the program as qualifying for allowance credit. By definition, offsets must be measures that are not required by the program and, in most cases, they cannot be required by any emission reduction program. They provide an incentive for low-cost investments in emission reductions as an alternative to higher-cost, in-sector reductions or allowance purchases. Offsets should be subject to stringent standards to ensure their environmental integrity. The C&T TWG was divided on the question of offsets. Nine members supported inclusion of unlimited offsets in lieu of in-sector reductions or allowances, one member supported a strictly limited use of offsets, and five members opposed offsets. Those supporting inclusion stated that rigorously scrutinized offsets create the same environmental benefit at a lower cost. Those opposed expressed concern that unlimited offsets could undermine the integrity of the cap; that with a broad multi-sector program, the opportunities for offsets would be limited; that the requirement that offsets be "additional" is very difficult to prove; and that the administrative burden of certifying offset projects can be excessive.

- *Safety Valve*—The MCCAG makes no recommendation on the issue of a safety valve. A "safety valve" is a program feature designed to limit or moderate the cost of allowances for the purpose of ensuring that the program will not have an unacceptable impact on consumer costs. Safety valves can be as direct and simple as an allowance price cap or as complex and indirect as the RGGI's stepped expansion of offset opportunities triggered by allowance prices. The C&T TWG was divided on the issue of a safety valve. Five members supported a firm price cap, while three supported some measure to moderate, but not cap, allowance prices. Three members were opposed to any form of a safety valve, and three were unprepared to decide. Those supporting the price cap said the feature would simply reflect the political reality that excess allowance prices would doom the program, and a price cap would protect against that result. Opponents stated that there were better tools to mitigate prices (such as banking), and the effect of hitting the cap would be to convert the cap-and-trade program into a carbon tax. Also expressed was the belief that it is more important that the GHG reductions are achieved than that the costs are limited.

- *Banking*—The MCCAG recommends that the cap-and-trade program allow unlimited banking of allowances. Banking permits allowance holders to withhold their allowances from the market or from surrender for emissions compliance without expiration and to use an allowance issued in any compliance period beyond that period without penalty. Banking is seen as a means of mitigating market volatility by allowing holders to hang onto allowances (thereby mitigating supply) when prices are low and to use or sell them (thereby mitigating demand) when prices are high. Nine C&T TWG members supported unlimited banking, two supported limited banking, one opposed banking, and two were unprepared to decide.

- *Borrowing*—The MCCAG makes no recommendation on the issue of allowance borrowing. Borrowing of allowances permits emitters to release excess tons of GHGs in the current compliance period in return for greater reductions in a future compliance period. Borrowing can be temporal (against future allowance distributions) or interparty (between regulated entities). The C&T TWG was divided on the question of borrowing, with two members in favor of unlimited borrowing, six in favor of limited borrowing, four opposed to borrowing, and three unprepared to decide. Supporters favor borrowing as offering greater flexibility for emitters; opponents fear the challenges of policing the practice and generally favor other mechanisms such as multiyear compliance periods.

Integration with Complementary Policies and Measures: The MCCAG strongly recommends that emission reductions resulting from complementary policies and measures (non–cap-and-trade) within capped sectors be credited toward the achievement of the cap, and that the cap be set accordingly.

Point of Regulation: The point of regulation is the entity responsible for acquiring and surrendering allowances for emissions. In some sectors, such as major industrial emissions, this is simply the entity operating the facility from which the emissions are released. But for other sectors it is either impractical or undesirable to use this approach. The MCCAG recommends the following point of regulation for each covered sector:

- *Electric Power Sector*—A load-based system that aligns with current energy planning regulatory requirements is recommended in order to capture the substantial emissions resulting from in-state consumption of imported electricity and to maximize cost-effective emission reductions.
- *Large Industrial Boilers and Processes, Waste Incinerators, Large Agricultural Operations, and Landfills*—A production-based system regulating direct emissions from each source is recommended.
- *Transportation Fuels and Fossil Fuels for Residential and Commercial Buildings*—An indirect or "upstream" system is recommended, requiring allowances from the entities importing or distributing the fuel into the Minnesota market. If a fuel used by a facility that is regulated on a production basis has been covered upstream, the program should be designed to eliminate double counting.

Distribution of Allowances: The MCCAG makes no recommendation on the issue of allowance distribution but recommends further study of five distribution alternatives. There are several models—including free distribution to covered sources on some basis, such as historical emissions (grandfathering), and auction at the market—that require covered sources to purchase the allowances. These options are not mutually exclusive; blends of both auction and free distribution are possible. If allowances are auctioned with proceeds collected by the state, these funds could be used to finance energy efficiency programs, promote development of sustainable low-carbon energy sources, assist low-income energy consumers, help any workers harmed by the transition away from high-carbon technologies, and provide rebates to consumers to offset the cost of the program. The C&T TWG examined both methods.

The members of the C&T TWG were divided between those who supported 100% free distribution (six members) and those who supported 100% auction (four members). In addition one member supported a mix of auction and free distribution, and two supported shifting from free distribution to auction over time. The committee and the MCCAG believe, however, that there should be further exploration of a number of compromise alternatives, including

- Partial auction-partial free distribution,
- Shift from free distribution to auction over time,
- Auction for unregulated entities and free distribution for regulated entities,

- Sector-specific distribution systems, and
- Performance-based market systems.

Implementation Mechanisms

Market-based programs include a variety of potential approaches that stimulate market demand for emission reductions, market supply of emission reduction actions, and implementation flexibility. Cap-and-trade is one such program. It is designed to create market demand for emission reductions by establishing a regulatory limit on emissions, stimulating market supply by providing trading opportunities among entities, and providing various flexibility mechanisms to contain costs. The C&T TWG also examined performance-based market approaches in addition to the cap-and-trade approach.

Related Policies/Programs in Place

A wide array of existing policies and measures are in place in Minnesota. New and expanded policies and measures are being recommended through this effort that will have a substantial interactive effect on a cap-and-trade program and vice versa. The MCCAG views a cap-and-trade program and the other recommended policies and measures within each capped sector as "overlapping." Therefore, the role of the cap-and-trade program is seen as reinforcing the implementation of policies needed to reach the emission reduction target or expanding the level of effort needed to reach the target. These policy areas include efficiency and conservation, renewable energy, transportation fuels and efficiency, waste management, and industrial processes.

Type(s) of GHG Reductions

All six statutory GHGs (CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6).

Estimated GHG Reductions and Net Costs or Cost Savings

Model scenarios for multistate options include

- MGA Partners C&T,
- MGA Partners plus Observers C&T,
- MGA Partners plus WCI Partners C&T,
- MGA Partners plus Observers and WCI Partners plus Observers C&T, and
- Minnesota-only C&T.

Each multistate scenario includes three sensitivity cases: (1) assume no renewable electricity standard (RES)/utility conservation improvement program (CIP) in the baseline condition of Minnesota, (2) assume both RES and CIP are in effect in the baseline condition of Minnesota, and (3) assume only RES is in effect in the baseline condition of Minnesota.

The simulation results given below are intended to provide basic insight to the economic implications of a cap-and-trade system. They are based on the best available data at the time of the writing of this report. The accuracy of the simulations will be enhanced as more primary data become available. Specifically, the most valuable data additions would provide information on GHG reduction capability and cost for mitigation/sequestration options in midwestern states and in WCI states for which primary data are not available at this time.

The cap-and-trade simulations yield the following model outputs and results.

Model outputs:

- Permit price, trading volume, and distribution of trading among states and sectors;
- Emission reductions of states and sectors before and after trading;
- Total cost and average (per ton) cost of compliance;
- Cost savings for each state from joining the cap-and-trade mechanism; and
- Comparison of the scenario effects of alternative GHG emission caps, timing, state coverage, sectoral coverage, allocation methods, flexibility mechanisms, cost curves, emissions baselines, level of complementary measures, and market concentration.

Summary of model results, as presented in Table 1:

- The factors that have the greatest influence on all simulations are the absolute levels and the relative levels of the marginal mitigation/sequestration cost curves. The former has the greatest influence on the potential for cost savings, while the latter has the greatest influence on the extent of permit trading across trading entities (sectors and states), including whether each state is a permit buyer or seller.
- The reference scenario assumes no RES and CIP in the baseline condition of Minnesota. The following are two sensitivity scenarios: (1) assume both RES and CIP are in effect in the baseline condition, and (2) assume only RES is in effect in the baseline condition. When RES and CIP (or only RES) are incorporated in the baseline condition, the Minnesota 2025 business-as-usual (BAU) emission level decreases, which results in a lower emission reduction requirement to reach 30% below the 2005 level, compared with the reference scenario. This also means that the mitigation options of RES and CIP (or only RES option) are removed from the policy option list that is used to develop the marginal cost curve, which results in an upward shift and steepening of the Minnesota marginal cost curve. The simulation results show that the effects of the lower emission reduction goal relative to the BAU level and the higher marginal cost curve nearly offset each other, e.g., the permit prices in the simulations of the sensitivity scenarios are only one or two dollars lower than the corresponding reference scenario.
- However, major differences do exist in total net cost and average mitigation cost of Minnesota between the reference scenario and the scenario with both RES and CIP in the baseline. The latter has both higher total net cost and higher average mitigation cost than the reference scenario. The major reason is that when RES and CIP are assumed to be in effect in the baseline, the CIP option (Residential, Commercial, and Industrial-1 (RCI-1), which has 14.7 MMtCO$_2$e reduction potential at the cost of –$63.20, is absorbed into the

baseline condition, i.e., the substantial cost savings associated with the implementation of CIP are incorporated into the baseline.

- The second sensitivity scenario, which assumes only RES is in effect in the baseline, yields a similar permit price, total net cost, and average mitigation cost to Minnesota as the reference scenario.
- The permit price of the MGA partner trading is in the range of \$45–\$48 per ton of CO_2 equivalent (\$/tCO_2e) across the three baseline scenarios. In all three of the baseline scenarios, the total cost of achieving the carbon emissions reductions is negative for many states. Minnesota's total cost is negative in two of the three scenarios, but positive in the recommended policy scenario (in which a renewable electricity standard [RES] and Conservation Improvement Program [CIP] are assumed to be in the baseline). This is because in the recommended baseline scenario, the substantial cost savings associated with CIP have been incorporated into the baseline condition of Minnesota. States with negative total costs will realize an overall cost savings, due to the extensive range of cost-saving options to reduce emissions (such as improvements in energy efficiency). Notwithstanding the positive total cost result for Minnesota—the cap-and-trade program—allows Minnesota to achieve its cap at a lower cost than would be the case without the program. Minnesota is a permit buyer in the simulations of all the geographic configurations. The biggest seller among the WCI states is California. The biggest seller in the MGA state simulations is Illinois. California is also the biggest seller in the simulations that include both WCI and MGA states. Kansas is the biggest permit buyer among the MGA states.
- Among the various configurations, the permit price is lower for the case of trading among MGA and WCI partners than in various other configurations. The worst case from Minnesota's standpoint (because the state is a permit buyer and this case would raise the permit price the most) would be to include observers from MGA. These results indicate that (1) WCI partners have overall lower mitigation/sequestration costs than the MGA states; (2) on average, the MGA observers have higher mitigation costs compared with the MGA partners; (3) WCI observers have overall higher mitigation/sequestration costs than WCI partners, but lower costs than MGA states. As a permit buyer, Minnesota would be better off joining a cap-and-trade program with WCI states, because it can buy permits at a lower price than in trading with only MGA states.
- In the Minnesota-only simulations, the model was run for trading among four major sectors within the state. In all three scenarios, the simulation results indicate that it would be better (attain more cost savings) for Minnesota to join a cap-and-trade system with other states than to achieve reduction goals on its own. The simulation results indicate that Power Sector and Other Sector would buy permits from Transportation Sector and Sequestration Sector.

Table K-1. Model results for multistate and Minnesota-only cap-and-trade scenarios

Policy No.	Policy Recommendation	GHG Reductions (MMtCO$_2$e)			Net Present Value (Million $)	Cost-Effective-ness* ($/tCO$_2$e) 2025	Permit Price† ($/tCO$_2$e) 2025	Level of Support
		2015	2025	Total (2008–2025)				
C&T-1	Cap-and-Trade Program							Majority (9 objections)
	MGA Partners C&T *—with both RES/CIP in the baseline*		52.94			$2.65	$45.95	
	MGA Partners C&T *—no RES/CIP in the baseline*		79.82			–$12.17	$48.45	
	MGA Partners C&T *—with only RES in the baseline*		67.35			–$15.42	$46.64	
	MGA Partners+Observers C&T *—no RES/CIP in the baseline*		81.97			–$10.52	$52.44	
	MGA Partners+Observers C&T *—with both RES/CIP in the baseline*		55.45			$4.71	$50.72	
	MGA Partners+Observers C&T *—with only RES in the baseline*		69.45			–$13.48	$51.27	
	MGA plus WCI Partners C&T *—no RES/CIP in the baseline*		72.64			–$17.52	$35.69	
	MGA plus WCI Partners C&T *—with both RES/CIP in the baseline*		46.93			–$2.19	$34.95	
	MGA plus WCI Partners C&T *—with only RES in the baseline*		61.92			–$20.36	$35.07	
	MGA and WCI Partners+Observers C&T *—no RES/CIP in the baseline*		76.17			–$14.92	$41.87	
	MGA and WCI Partners+Observers C&T *—with both RES/CIP in the baseline*		50.41			$0.59	$41.25	
	MGA and WCI Partners+Observers C&T *—with only RES in the baseline*		64.92			–$17.65	$41.39	
C&T-2	Minnesota-Only C&T *—no RES/CIP in the baseline* (merged into C&T-1)		89.18			–$2.39	$65.48	

GHG = greenhouse gas; MMtCO$_2$e = million metric tons carbon dioxide equivalent; $/tCO$_2$e = dollars per metric ton of carbon dioxide equivalent; MGA = Midwestern Governors Association; C&T = cap-and-trade; RES = renewable electricity standard; CIP = conservation improvement program; WCI = Western Climate Initiative.

Data Sources:

Marginal cost curves for states and provinces are developed directly (1) on the basis of assessment of state-level actions developed through state and provincial planning processes in Arizona, Colorado, Montana, New Mexico, and Washington (developed on the basis of mitigation costs of individual policy options presented in Center for Climate Strategies [CCS] reports or other assessments of the respective state climate change action plans); or (2) by approximation methods for other states using a parametric shift method based on cost curves from states with actual data. The C&T TWG developed the marginal cost curves of other western states based on New Mexico's actual cost data and developed the marginal cost curves of midwestern states based on Minnesota's actual cost data. No direct cost curve data are available for other midwestern states at present.

Emission projections data come from (1) CCS inventory and forecast studies of respective states, or (2) the Energy Information Administration's *Annual Energy Outlook 2007* and *Canada's Energy Outlook 2006* (from Natural Resources Canada) for states lacking detailed bottom-up assessments.

Quantification Methods:

The modeling of various cap-and-trade scenarios under C&T-1 used a nonlinear programming model of emission allowance trading. This model is based on the well-established principles of the ability of unrestricted permit trading to achieve a cost-effective allocation of resources in the presence of externalities.[1] The model requires equalization of the marginal cost of all trading participants with the equilibrium permit price. This ensures minimization of total net compliance costs for each state and minimization of total abatement costs for the cap-and-trade program as a whole.[2]

Key Assumptions:

The purpose of the simulations is to illustrate the economic impacts of a cap-and-trade program to Minnesota under particular design scenarios. It does not intend to define the final details of a prospective cap-and-trade regulatory program, but rather stands ready to model any design configuration proposed by the TWG.

All emissions considered are consumption-based and are gross emissions (excluding sinks).

The economic modeling conducted in this study helps to analyze the potential GHG reductions and associated costs for Minnesota under several scenarios of different design configurations using the following variables: emission caps, timing, state coverage, sectoral coverage, allocation methods (auctioning versus free granting of permits), flexibility mechanisms, cost curves, emission baselines, level of complementary measures, and market concentration.

A full list of assumptions adopted in the simulation model is presented in the annex.

Key Uncertainties

A number of design variables and the quality of data for cost curves and emission projections can affect permit prices, volume and distribution, including targets, timing, state coverage, sectoral coverage, allocation methods, flexibility mechanisms, cost curves, emission baselines, trade/no trade, level of complementary measures, and market concentration.

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[1] See, for example, T. Tietenberg (1985), *Emissions Trading: An Exercise in Reforming Pollution Policy,* Washington, DC, Resources for the Future.

[2] See, for example, B. Stevens and A. Rose (2002), "A dynamic analysis of the marketable permits approach to global warming policy: A comparison of spatial and temporal flexibility," *Journal of Environmental Economics & Management* 44(1):45–69; A. Rose, T. Peterson, and Z. Zhang (2006), "Regional Carbon Dioxide Permit Trading in the United States: Coalition Choices for Pennsylvania," *Penn State Environmental Law Review* 14(2):203–229.

Additional Benefits and Costs

In addition to direct costs of compliance and GHG emission reductions, other potential impacts are possible on labor, value added, income, market share of industries, energy independence, energy prices, air quality, and other environmental or economic outcomes.

Feasibility Issues

A number of technical feasibility issues relate to cap-and-trade program implementation, including transaction costs and point of regulation.

Status of Group Approval

Complete.

Level of Group Support

Majority (9 objections).

Barriers to Consensus

Those objecting to this option expressed concern that industries in the MGA region, and therefore within Minnesota, would be placed at a competitive disadvantage relative to counterparts operating outside the MGA jurisdictions. Also expressed was the concern that the time and effort devoted to the creation of a regional program would divert attention away from the development of a comprehensive national program, which was preferred.

Another objection to the policy was due to the inclusion of fossil fuels used in residential and small commercial buildings. It was stated that natural gas customers have very limited alternative fuel options offering lower carbon emissions. It was feared that inclusion of this sector would create significant additional costs for small natural gas customers without a corresponding reduction in GHG emissions. Finally, some expressed concern for the inclusion of large agricultural operations.

C&T-4. Carbon Tax

Policy Description

The MCCAG does not support the creation of a carbon tax. The C&T TWG was divided between those who opposed a carbon tax and those who felt there was insufficient time to thoroughly consider the option. Most members of the TWG believe that by recommending a broad, regional, multi-sector cap-and trade-program, any need for or benefit from a complementary carbon tax is satisfied.

A carbon tax sets a fee, or tax, for the release of carbon to the atmosphere. It does not set a limit on, reduce, or otherwise control the tons of carbon released. The tax raises the cost of carbon-based emissions; therefore, it encourages investment in low-carbon or no-carbon alternatives. It also generates revenue for the government that could be directed toward energy efficiency, the development and use of renewable energy, climate change adaptation investments, and other measures to mitigate or address the impacts of climate change. A carbon tax could be implemented as a tax on fossil fuels according to the amount of CO_2 emitted by their combustion. One of the benefits is that it can be more easily applied across all sectors.

It is assumed that the cost of the tax would be passed down to the ultimate consumer, such as residential and commercial utility ratepayers for electricity. To achieve the stated goal, the amount of the tax must be high enough to trigger financial and behavioral decisions toward conservation or a shift to lower-emitting fuels.

Policy Design

Goals: Make the cost of inefficient or higher-CO_2-emitting activities more expensive than alternatives, thereby creating a financial incentive to change behavior away from activities that result in CO_2 emissions. The tax should include safety valves to reduce impacts on low-income citizens and minimize detrimental economic consequences. One option is to make the tax "revenue neutral" (an equal amount of other state taxes would be reduced so that the "net" to the state is zero), or the revenue from the tax could be used to develop or promote alternatives that reduce CO_2 emissions. The amount of the tax should be high enough to contribute to the reduction targets specified in the statute.

Timing: Not applicable (this policy is not recommended).

Parties Involved: Major payers would be utilities that generate or distribute electricity in Minnesota, refiners or distributors of transportation and heating fuels in Minnesota, and commercial and industrial sources creating energy for production or other commercial use.

Other: Not applicable.

Implementation Mechanisms

This option requires legislation and the creation or expansion of administrative tax collection and enforcement capabilities.

Related Policies/Programs in Place

None, although policy option C&T-1 (Cap-and-Trade) is seen as sufficiently comprehensive to make a carbon tax unnecessary.

Type(s) of GHG Reductions

Reductions in emissions of CO_2 from combustion sources.

Estimated GHG Reductions and Net Costs or Cost Savings

Not applicable (this policy is not recommended).

Data Sources: Not applicable (this policy is not recommended).

Quantification Methods: Not applicable (this policy is not recommended).

Key Assumptions: Not applicable (this policy is not recommended).

Key Uncertainties

Not applicable (this policy is not recommended).

Additional Benefits and Costs

Not applicable (this policy is not recommended).

Feasibility Issues

Not applicable (this policy is not recommended).

Status of Group Approval

Not recommended.

Level of Group Support

Not applicable (this policy is not recommended).

Barriers to Consensus

Not applicable (this policy is not recommended).

C&T-5. Market Advisory Group (Formerly CC-11)

Policy Description

The MCCAG recommends that MGA partners create a Market Advisory Group consisting of experts to provide guidance to the region on the design of market-based compliance programs to manage GHG emissions. California has formed a Market Advisory Committee (MAC) to help formulate a GHG cap-and-trade system in the state. The California MAC has proposed a set of guiding principles and has developed an initial set of recommendations for a California cap-and-trade program. The MCCAG recommends that the MGA convene a similar Market Advisory Group to receive the policy recommendations of the MCCAG and provide expert guidance to the partners on the design of a Midwest regional cap-and-trade program to manage GHG emissions.

Several members of the C&T TWG also support the creation of a Minnesota Market Advisory Group to advise the state on cap-and-trade program design.

Policy Design

Goals: The MCCAG recommends the creation of a regional, multi-sector cap-and-trade program to help manage GHG emissions. This recommendation contains policy guidance in the areas of jurisdictional coverage, sector coverage, timing, early actions, and banking. Before a program can be implemented, however, this guidance must be refined into a detailed program design. The appointment of a Market Advisory Group is recommended for this purpose.

Timing: To provide the earliest possible guidance to covered sectors, the Market Advisory Group should be appointed as soon as possible after the MCCAG recommendations are received by the MGA partners.

Parties Involved: Unlike the MCCAG, which is stakeholder-driven, the Market Advisory Group should be composed of individuals with particular expertise in key areas, such as economics, markets, climate science and policy, cap-and-trade programs in other jurisdictions or for other pollutants, key covered sectors, and finance.

Other: The Market Advisory Group should encourage public comment throughout its deliberations.

Implementation Mechanisms

The Market Advisory Group could be created by agreement among the MGA partners and should serve for a limited time. The product of the Market Advisory Group’s deliberations should be a report or reports recommending in some detail the scope, design, and plan for implementation of the MGA regional cap-and-trade program.

Related Policies/Programs in Place

No related policies or programs are currently in place. However, MCCAG policy options C&T-1 (Cap-and-Trade Program) and C&T-6 (Participate in Regional or Multistate GHG Reduction Efforts) could both be related to the creation of a Market Advisory Group.

Type(s) of GHG Reductions

If the recommendations contained under C&T-1 (Cap-and-Trade Program) are adopted, all six major GHGs (CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6) would be reduced.

Estimated GHG Reductions and Net Costs or Cost Savings

Not quantified.

Data Sources: Not applicable.

Quantification Methods: Not applicable.

Key Assumptions: Not applicable.

Key Uncertainties

Not applicable.

Additional Benefits and Costs

Not applicable.

Feasibility Issues

Not applicable.

Status of Group Approval

Complete.

Level of Group Support

Unanimous consent.

Barriers to Consensus

Not applicable.

C&T-6. Participate in Regional and Multistate GHG Reduction Efforts (Formerly CC-7)

Policy Description

As a general policy, the MCCAG encourages exploration of opportunities for regional market-based approaches to reduce GHG emissions. The MCCAG believes that this recommendation is met through the implementation of a regional multi-sector cap-and-trade program as proposed in C&T-1. However, there may be additional opportunities for enhanced GHG reductions through coordinated regional action. The MCCAG, through its C&T TWG, has not had sufficient time to fully explore regional opportunities beyond the proposal under C&T-1.

Regional approaches undertaken in collaboration with partner states or other organizations can offer broader and more economically efficient opportunities to reduce GHG emissions across Minnesota's economy. As has been demonstrated through the investigation of a regional cap-and-trade program, the cost to achieve targeted reductions in Minnesota can be lower through a regional effort than would be the case if Minnesota pursued a similar policy on its own. An additional example might be to include cost sharing on multistate initiatives.

Policy Design

Goals: Ensure the cost-effective reduction of GHG emissions to at least the reduction levels set forth in Minnesota statutes in a manner that maximizes public benefits and induces innovation in energy efficiency and sustainable energy technologies and avoids inequitable impacts.

Timing: The Pawlenty administration has already announced its intention to participate in the Midwest Governor's Regional Greenhouse Gas Reductions Accord (MGA), a six-state and one Canadian province initiative to design and implement a regional cap-and-trade program for GHG emission reductions. On February 1, 2008, the administration reported to the legislature on its investigation into regional GHG reduction opportunities and the decision to participate in the accord. The recommendations of the MCCAG have informed that report.

Parties Involved: The Governor and his staff should implement the legislative directive (see below) and inform the chairs and ranking minority members of the legislative committees with jurisdiction over energy and environmental finance and policy.

Other: None.

Implementation Mechanisms

Next Generation Energy Act, S.F. No. 145, Article 5, Sec. 2, Subd. 6 (Regional activities). To the extent possible, the state must develop and implement, with other midwestern states, a regional approach to reducing GHG emissions from activities in the region, including consulting on a regional cap-and-trade system.

Related Policies/Programs in Place

Next Generation Energy Act, S.F. No. 145, Article 5, Sec. 2, Subd. 6 (Regional activities). See above.

Type(s) of GHG Reductions

If the MGA adopts the policy design recommended by the MCCAG, the reductions will occur across multiple sectors (power, transportation, industrial, agricultural, waste management, residential, and commercial) and will include the reductions resulting from a suite of policies and mechanisms designed to reduce emissions across these sectors.

Estimated GHG Savings and Costs per tCO_2e

See C&T-1 for cap-and-trade savings and costs.

Key Uncertainties

Joining another regional entity should not compromise the achievement of Minnesota's goal.

Additional Benefits and Costs

Minnesota's participation in a regional GHG emission reduction initiative that meets the state's goals will result in additional environmental and economic co-benefits, including the opportunity to reduce GHG emissions in an economically efficient manner, the identification of additional areas for cooperation within specific sectors (e.g., transportation), and the reduction of other non-GHG pollutants associated with the production and use of energy.

Feasibility Issues

Given that Illinois, Iowa, Kansas, Michigan, Minnesota, Wisconsin, and Manitoba have agreed to pursue a major regional program, and other regions are undertaking similar initiatives, the feasibility issues have been considered and are being satisfactorily addressed by the participants.

Status of Group Approval

Completed.

Level of Group Support

Unanimous consent.

Barriers to Consensus

Not applicable.

C&T-7. Facilitate the Development of an Effective Carbon Credit System for Minnesota (Formerly CC-10)

Policy Description

The MCCAG believes its C&T TWG has not had sufficient time to thoroughly study or consider this option. Also, lacking the opportunity to study the administration's recently announced plan to pursue a similar policy, the MCCAG declines to offer a recommendation on this policy.

GHG reductions from a wide variety of sources and actors could be undertaken in order to participate in offset programs or markets. Minnesota could develop an offset program as a state-led or private effort. Under this policy, one approach is for entities to participate in an official state-recognized registry. However, for entities not covered by the registry, the policy should allow for offsets to be submitted as a way to opt in to GHG emission allowance markets or trading systems. Such offsets would be registered using approved protocols or, in the absence of protocols, an application for approval of specific projects on a case-by-case basis. The effectiveness of such offsets is likely to help determine their value and utility for participants. In particular, concerns about measurement, permanence, additionality, and enforceability must be resolved in the protocol-setting process. Such measures as categorical exclusions and temporary credits for certain types of emission-reducing actions should be considered. However, the administrative burden and/or transaction costs that could be imposed could have a countervailing (dampening) effect, leading to an overall increase in costs.

Policy Design

Goals: Enable a wide range of quality offsets to be generated in Minnesota, with the applicability of such offsets to be determined as state, regional, national, and international GHG reduction efforts continue to develop. Criteria for such an offset system in Minnesota might include real, surplus (additional), verifiable, permanent, and enforceable.

Timing: By January 1, 2009, establish an offset program for use by Minnesota entities, including at a minimum the major sectors for which existing GHG emission reduction protocols exist or are developed. To the extent that Minnesota's participation in *The Climate Registry* will enable certain sectors and/or entities to participate in offset creation, those sectors and/or entities would not be included in the separate offset program under this policy.

Parties Involved: Minnesota Department of Commerce and the MPCA, along with other appropriate partners. The offset program tracking and administration could be formed with the same agency structure as envisioned for the state's participation in *The Climate Registry*. A stakeholder and public comment process should be employed during 2008 to determine types of offsets and relevant protocols for inclusion.

Other: Consider a state purchase of offsets using an RFP (request for proposals) process to jump-start the market versus strong advocacy for rapid development of national or regional offset systems.

Implementation Mechanisms

Legislative authorization for the agency-based offset program, including funding for staff and associated stakeholder processes will be required. The need for protocol development, approval processes, such as applications or third-party verification, and possible participant funding for protocols and/or verification should be considered.

Related Policies/Programs in Place

Climate inventories and registries, county or municipal offset efforts.

Type(s) of GHG Reductions

A wide variety, including forestry and land use, process and end-use efficiency, innovative technologies (e.g., hybrid vehicle conversions).

Estimated GHG Savings and Costs per tCO_2e

Savings are unknown at this time. Note that offsets, if sold to out-of-state emission markets with such binding regulatory regimes as the European Union's, could be used by others and would not lead to overall (global or Minnesota) emission reductions. Only emissions that are recorded and retired permanently in Minnesota or sold into voluntary emission markets, such as the Chicago Climate Exchange, are actually "real and additional" GHG reductions. Concerns about the permanence of land use and other behaviors introduce further uncertainty, as does the permissibility of offsets for use in a potential mandatory GHG emission reduction program.

Key Uncertainties

Key uncertainties include the willingness of Minnesota actors to undertake offset investments, the stringency of offset accounting and the resulting quality of offsets, ties to external markets and pricing, and public (agency) versus private (nonprofit or for-profit organization) oversight and program administration.

Additional Benefits and Costs

Probably include unquantifiable co-benefits from emission reduction actions; benefits for actors to develop GHG accounting, option evaluation, and institutional infrastructure to facilitate GHG emission reduction efforts; and the potential to pave the way for other policies.

Feasibility Issues

The time and resources to develop an offset program and any required protocols or verification methods are unknown. In addition, offset evaluation and verification can be administratively demanding.

Status of Group Approval

Due to time constraints limiting MCCAG analysis and development, this policy is not recommended.

Level of Group Support

Not applicable.

Barriers to Consensus

Not applicable.

Annex

1. The following is a summary of the full list of assumptions we adopted in our simulation model.

Geographical Configurations

- **M1:** Midwestern C&T partners—Iowa, Illinois, Kansas, Michigan, Minnesota, Wisconsin, and Manitoba
- **M2:** Midwestern C&T partners and observers—Iowa, Illinois, Kansas, Michigan, Minnesota, Wisconsin, and Manitoba plus Indiana, Ohio, and South Dakota
- **W1:** WCI partners—Arizona, California, New Mexico, Oregon, Utah, Washington, British Columbia, and Manitoba
- **W2:** WCI partners and five observers—Arizona, California, New Mexico, Oregon, Utah, Washington, British Columbia, and Manitoba plus Colorado, Idaho, Montana, Nevada, and Wyoming

Multistate Cap-and-Trade Cases

Case I—Assume no RES and CIP in the baseline condition of Minnesota.

- The simulation target year is 2025 and the emission mitigation target is 30% below 2005 level in year 2025.
- All sectors are included in the emission accounting and mitigation effort.
- All GHG emissions are considered.
- All gross emissions (excluding sinks) are considered.
- All emissions are consumption-based.
- Emission data for WCI states come from CCS inventories and forecasts studies for respective states; emission projections in 2025 are estimated based on the assumption that the annual growth rate between 2020 and 2025 is the same as the annual growth rate between 2005 and 2020 projected by CCS.
- Emission projections in 2025 for Minnesota come from CCS inventory and forecast estimates.
- Emission projections in 2025 for Midwestern states other than Minnesota are calculated based on Energy Information Administration (EIA) regional projected emission growth rates: Iowa, Kansas, and South Dakota belong to West North Central Region; Indiana, Illinois, Ohio, Michigan, and Wisconsin belong to East North Central Region.

- Emission projections for the two Canadian provinces come from *Canada's Energy Outlook 2006* by Natural Resources Canada; again, we assume the same annual growth rate of total emissions in 2020–2025 as in 2005–2020.
- Offsets are not included.
- No safety valve (permit price limit) is included.
- The allowance auction is simulated only for the MGA partner case. In the auction case, there would be no permit trading among states; however, in equilibrium, each state will choose to mitigate the same level of emission as it would in a permit trading market; each state would buy its total allowances from the auctioneer. The auction price would be the same level as the equilibrium price in a permit trading market.
- Recycling of auction revenues is not analyzed in the simulations.
- Marginal cost curves embody direct mitigation costs only.
- Marginal cost curves do not include various transactions costs.
- Marginal cost curves do not distinguish between producer vs. consumer allocation of permits.
- Marginal cost curves for Arizona, New Mexico, Colorado, Montana, Washington, and Minnesota are developed based on mitigation costs of individual policy options presented in CCS reports of the respective State Climate Change Action Plans.
- Marginal cost curves of other WCI states (provinces) are developed by a parametric shift method using New Mexico's marginal cost curve as a reference; marginal cost curves of other midwestern states (provinces) are developed by a parametric shift method using Minnesota's marginal cost curve as a reference; the parametric shift rule assumes a direct relationship between the slope of the marginal cost curve and the carbon intensity of a state.
- In order to run simulations including both MGA and WCI states in year 2025, we used 2020 marginal cost curves for WCI states for 2025; we also assumed that the same emission cap in 2025 (30% below the 2005 level) for MGA states applies to WCI states as well.

Case II—Assume both RES and CIP are in effect in the baseline condition of Minnesota.

- Same assumptions as for Case I, except,
    - When RES and CIP are already factored in the BAU case, the corresponding policy options are excluded from the option list to develop the Minnesota marginal cost curve: (1) RCI-1: Maximize Savings from the Utility Conservation Improvement Program and (2) ES-5: Renewable and/or Environmental Portfolio Standard
    - Marginal cost curves for other midwestern states are still developed based on Minnesota's curve in Case I.

Case III—Assume only RES are in effect in the baseline condition of Minnesota.

- Same assumptions as for Case I, except,

  - When RES is already factored in the BAU case, the corresponding policy option is excluded from the option list to develop the Minnesota marginal cost curve: ES-5: Renewable and/or Environmental Portfolio Standard
  - Marginal cost curves for other midwestern states are still developed based on Minnesota's curve in Case I.

Minnesota-only Cap-and-Trade

- Assume the cap-and-trade is undertaken among four major sector categories: (1) Power Sector, (2) Transportation Sector, (3) Sequestration Sector, and 4) Other Sector.
- Assume the cap of 30% below the 2005 level in 2025 applies to Power Sector, Transportation Sector, and Other Sector, i.e., in 2025 each sector has an emission cap of 70% of its emission level in 2005.
- Assume the BAU emission from the Sequestration Sector in 2025 is zero, and this sector does not have a cap.

2. The model yields the following general results:

- GHG emission reductions for each state (sector) before and after permit trading
- Cost of GHG emission reductions for each state (sector) before and after trading
- Auction value of permits (relevant cases)
- Number of permits traded (bought and sold) by each state (sector)
- Equilibrium permit price
- Cost savings for each state (sector) of joining the Cap-and-Trade mechanism

Multistate Cap-and-Trade Simulations

Key

States in the United States

AZ = Arizona
CA = California
CO = Colorado
IA = Iowa
ID = Idaho
IL = Illinois
IN = Indiana
KS = Kansas
MI = Michigan
MN = Minnesota
MT = Montana
NM = New Mexico
NV = Nevada
OH = Ohio
OR = Oregon
SD = South Dakota
UT = Utah
WA = Washington
WI = Wisconsin
WY = Wyoming

Canadian Provinces

BC = British Columbia
MB = Manitoba

Sensitivity Analysis #1: CIP and RES are not in effect in the baseline condition.

Table A-1. (I-M1)—Economy-wide emission trading simulation among six midwestern states plus Manitoba in 2025 (million $ or otherwise specified)

	Before Trading	**After Trading***				**Permits Traded**	**Emission Reduction With Trading**		**Emission Reduction Goal**
State	**Mitigation Cost**	**Mitigation Cost**	**Trading Cost**	**Net Cost**	**Cost Saving**	**(MMtCO$_2$e)**	**(MMtCO$_2$e)**	**(Percent From BAU)**	**(Percent From BAU)**
IA	–$478	–$910	$344	–$565	$87	7.10	47.91	38.01	43.65
IL	–$1,581	–$941	–$756	–$1,697	$116	–15.61	138.64	43.02	38.18
KS	–$621	–$1,392	$510	–$882	$261	10.53	42.27	34.94	43.65
MI	–$1,663	–$1,445	–$234	–$1,679	$16	–4.83	109.06	39.95	38.18
MN	–$439	–$972	$451	–$521	$81	9.31	79.82	40.38	45.09
WI	–$915	–$706	–$233	–$939	$24	–4.81	67.32	41.11	38.18
MB	–$178	–$122	–$83	–$204	$26	–1.70	8.10	39.29	31.02
Total	**–$5,876**	**–$6,487**	**$0**	**–$6,487**	**$611**	**26.94**[†]	**493.11**	**40.28**	**40.28**

MMtCO$_2$e = million metric tons of carbon dioxide equivalent; BAU = business as usual.

* Permit Price = $48.45/tCO$_2$e. This is the price of the last permit sold, which is also equal to the price of the last ton of CO$_2$e mitigated (its *marginal* mitigation cost). It is the same for each state for a given case. The *average* mitigation cost per unit of CO$_2$e in this simulation differs for each state. For Minnesota, for example, it is –$12.17/tCO$_2$e. Please note that the average mitigation cost is related to mitigation level of a state which, for this case, is 40.38% below the baseline level in 2025 for Minnesota. Multiplying the average mitigation cost by the number of tons of CO$_2$ mitigated will equal the *total* mitigation cost for each state.

[†] Represents number of permits bought or sold.

Table A-2. (I-M2)—Economy-wide emission trading simulation among nine midwestern states plus Manitoba in 2025 (million $ or otherwise specified)

	Before Trading	**After Trading[*]**				**Permits Traded**	**Emission Reduction After Trading**		**Emission Reduction Cap**
State	**Mitigation Cost**	**Mitigation Cost**	**Trading Cost**	**Net Cost**	**Cost Saving**	**($MMtCO_2e$)**	**($MMtCO_2e$)**	**(Percent From BAU)**	**(Percent From BAU)**
IA	–$478	–$850	$310	–$539	$61	5.92	49.10	38.95	43.65
IL	–$1,581	–$737	–$1,030	–$1,767	$186	–19.64	142.67	44.28	38.18
KS	–$621	–$1,348	$506	–$842	$221	9.65	43.15	35.67	43.65
MI	–$1,663	–$1,298	–$406	–$1,704	$41	–7.74	111.97	41.01	38.18
MN	–$439	–$863	$375	–$488	$49	7.15	81.97	41.47	45.09
WI	–$915	–$612	–$350	–$962	$47	–6.67	69.19	42.25	38.18
MB	–$178	–$111	–$100	–$211	$33	–1.92	8.31	40.31	31.02
IN	–$2,954	–$3,357	$362	–$2,995	$41	6.91	113.91	36.00	38.18
OH	–$3,018	–$3,056	$38	–$3,019	$0	0.72	148.29	38.00	38.18
SD	–$64	–$553	$295	–$258	$195	5.62	17.13	35.49	47.13
Total	**–$11,911**	**–$12,785**	**$0**	**–$12,785**	**$874**	**35.96[†]**	**785.69**	**39.70**	**39.70**

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent; BAU = business as usual.

[*] Permit Price = \$52.44/tCO_2e. This is the price of the last permit sold, which is also equal to the price of the last ton of CO_2e mitigated (its *marginal* mitigation cost). It is the same for each state for a given case. The *average* mitigation cost per unit of CO_2e in this simulation differs for each state. For Minnesota, for example, it is –\$10.52/tCO_2e. Please note that the average mitigation cost is related to mitigation level of a state which, for this case, is 41.47% below the baseline level in 2025 for Minnesota. Multiplying the average mitigation cost by the number of tons of CO_2 mitigated will equal the *total* mitigation cost for each state.

† Represents number of permits bought or sold.

Table A-3. (I-M1W1)—Economy-wide emission trading simulation among six midwestern states, six western states, and two Canadian provinces in 2025 (million $ or otherwise specified)

	Before Trading	After Trading*				Permits Traded	Emission Reduction After Trading		Emission Reduction Cap
State	Mitigation Cost	Mitigation Cost	Trading Cost	Net Cost	Cost Saving	(MMtCO$_2$e)	(MMtCO$_2$e)	(Percent From BAU)	(Percent From BAU)
AZ	$2,954	–$1,579	$1,756	$177	$2,778	49.19	70.39	37.17	63.14
CA	$459	$3,847	–$4,893	–$1,046	$1,505	–137.09	443.29	68.41	47.25
NM	$421	–$296	$459	$162	$259	12.85	35.33	35.50	48.41
OR	$89	$401	–$395	$7	$82	–11.06	54.38	59.18	47.15
UT	$528	$161	$304	$465	$62	8.52	50.14	46.79	54.74
WA	$3,666	–$792	$1,268	$476	$3,190	35.53	30.52	23.04	49.86
BC	$29	$96	–$71	$25	$4	–1.99	37.07	45.67	43.22
IA	–$478	–$1,074	$393	–$681	$202	11.01	44.00	34.91	43.65
IL	–$1,581	–$1,508	–$75	–$,583	$2	–2.09	125.12	38.83	38.18
KS	–$621	–$1,514	$479	–$1,035	$414	13.43	39.37	32.55	43.65
MI	–$1,663	–$1,850	$172	–$1,678	$15	4.82	99.41	36.41	38.18
MN	–$439	–$1,273	$588	–$685	$245	16.48	72.64	36.75	45.09
WI	–$915	–$967	$50	–$917	$2	1.40	61.12	37.33	38.18
MB	–$178	–$151	–$36	–$187	$9	–1.01	7.40	35.90	31.02
Total	**$2,271**	**–$6,499**	**$0**	**–$6,499**	**$8,770**	**153.23**[†]	**1,170.19**	**45.46**	**45.46**

MMtCO$_2$e = million metric tons of carbon dioxide equivalent; BAU = business as usual.

* Permit Price = $35.69/tCO$_2$e. This is the price of the last permit sold, which is also equal to the price of the last ton of CO$_2$e mitigated (its *marginal* mitigation cost). It is the same for each state for a given case. The *average* mitigation cost per unit of CO$_2$e in this simulation differs for each state. For Minnesota, for example, it is –$17.52/tCO$_2$e. Please note that the average mitigation cost is related to mitigation level of a state which, for this case, is 36.75% below the baseline level in 2025 for Minnesota. Multiplying the average mitigation cost by the number of tons of CO$_2$ mitigated will equal the *total* mitigation cost for each state.

† Represents number of permits bought or sold.

Table A-4. (I-M2W2)—Economy-wide emission trading simulation among nine midwestern states, eleven western states, and two Canadian provinces in 2020 (million $ or otherwise specified)

	Before Trading	After Trading*				Permits Traded	Emission Reduction After Trading		Emission Reduction Cap
State	Mitigation Cost	Mitigation Cost	Trading Cost	Net Cost	Cost Saving	(MMtCO$_2$e)	(MMtCO$_2$e)	(Percent From BAU)	(Percent From BAU)
AZ	$,954	–$1,458	$1,929	$471	$2,483	46.07	73.51	38.82	63.14
CA	$459	$4,995	–$6,983	–$1,988	$2,446	–166.77	472.96	72.98	47.25
NM	$421	–$216	$451	$235	$186	10.77	37.41	37.59	48.41
OR	$89	$555	–$630	–$74	$163	–15.04	58.36	63.51	47.15
UT	$528	$303	$203	$507	$21	4.86	53.80	50.21	54.74
WA	$3,666	–$738	$1,430	$691	$2,975	34.14	31.90	24.08	49.86
BC	$29	$200	–$195	$4	$25	–4.67	39.75	48.97	43.22
CO	$1,611	–$1,059	$1,239	$180	$1,431	29.59	48.82	30.56	49.08
ID	$26	$163	–$165	–$2	$28	–3.94	24.53	52.58	44.13
MT	$33	–$104	$110	$6	$27	2.63	14.73	34.03	40.10
NV	$354	$443	–$93	$350	$5	–2.22	49.54	60.43	57.72
WY	$506	–$571	$522	–$49	$555	12.47	23.22	31.11	47.82
IA	–$478	–$999	$381	–$619	$140	9.10	45.92	36.43	43.65
IL	–$1,581	–$1,250	–$367	–$1,616	$36	–8.76	131.79	40.90	38.18
KS	–$621	–$1,459	$503	–$956	$335	12.01	40.79	33.72	43.65
MI	–$1,663	–$1,666	$3	–$1,663	$0	0.08	104.16	38.15	38.18
MN	–$439	–$1,136	$542	–$594	$155	12.95	76.17	38.54	45.09
WI	–$915	–$848	–$69	–$918	$3	–1.66	64.18	39.19	38.18
MB	–$178	–$138	–$56	–$194	$16	–1.35	7.74	37.57	31.02
IN	–$2,954	–$3,657	$556	–$3,101	$147	13.27	107.55	33.99	38.18
OH	–$3,018	–$,490	$415	–$3,075	$56	9.92	139.09	35.64	38.18
SD	–$64	–$597	$274	–$323	$259	6.55	16.20	33.57	47.13
Total	**–$1,235**	**–$12,727**	**$0**	**–$12,727**	**$11,492**	**204.40†**	**1,662.13**	**44.50**	**44.50**

MMtCO$_2$e = million metric tons of carbon dioxide equivalent; BAU = business as usual.

* Permit Price = $41.87/tCO$_2$e. This is the price of the last permit sold, which is also equal to the price of the last ton of CO$_2$e mitigated (its *marginal* mitigation cost). It is the same for each state for a given case. The *average* mitigation cost per unit of CO$_2$e in this simulation differs for each state. For Minnesota, for example, it is –$14.92/tCO$_2$e. Please note that the average mitigation cost is related to mitigation level of a state which, for this case, is 38.54% below the baseline level in 2020 for Minnesota. Multiplying the average mitigation cost by the number of tons of CO$_2$ mitigated will equal the *total* mitigation cost for each state.

† Represents number of permits bought or sold.

Table A-5. Summary Data Table

State	Cap: 30% Below 2005 Emissions in 2025 ($MMtCO_2e$)	2025 BAU Gross Emissions (Consumption-Based) ($MMtCO_2e$)	GHG Mitigation Goal in 2025 (Relative to BAU Emissions)	Autarkic Marginal Mitigation Cost ($\$/tCO_2e$)	Gross State Product in 2025 (million $ 2000)
AZ	69.8	189.4	63.14%	$159.6	$481,628
CA	341.8	648.0	47.25%	$15.5	$2,923,222
NM	51.3	99.5	48.41%	$77.6	$94,564
OR	48.6	91.9	47.15%	$21.5	$297,081
UT	48.5	107.2	54.74%	$50.8	$204,725
WA	66.4	132.5	49.86%	$229.0	$471,781
BC	46.1	81.2	43.22%	$31.3	$146,610
CO	81.3	159.8	49.08%	$143.8	$563,455
ID	26.1	46.7	44.13%	$28.1	$98,835
MT	25.9	43.3	40.10%	$63.1	$41,520
NV	34.7	82.0	57.72%	$37.8	$236,707
WY	39.0	74.7	47.82%	$135.2	$39,577
IA	71.0	126.0	43.65%	$73.4	$206,621
IL	199.2	322.2	38.18%	$33.8	$768,315
KS	68.2	121.0	43.65%	$99.2	$146,593
MI	168.8	273.0	38.18%	$42.0	$524,088
MN	108.5	197.7	45.09%	$66.2	$392,084
WI	101.2	163.8	38.18%	$38.5	$342,743
MB	14.2	20.6	31.02%	$18.5	$37,581
IN	195.6	316.5	38.18%	$64.3	$396,501
OH	241.3	390.3	38.18%	$53.3	$590,200
SD	25.5	48.3	47.13%	$124.2	$57,361
Total	**2,073.1**	**3,735.2**	**44.50%**		**$9,061,793**

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent; BAU = business as usual.

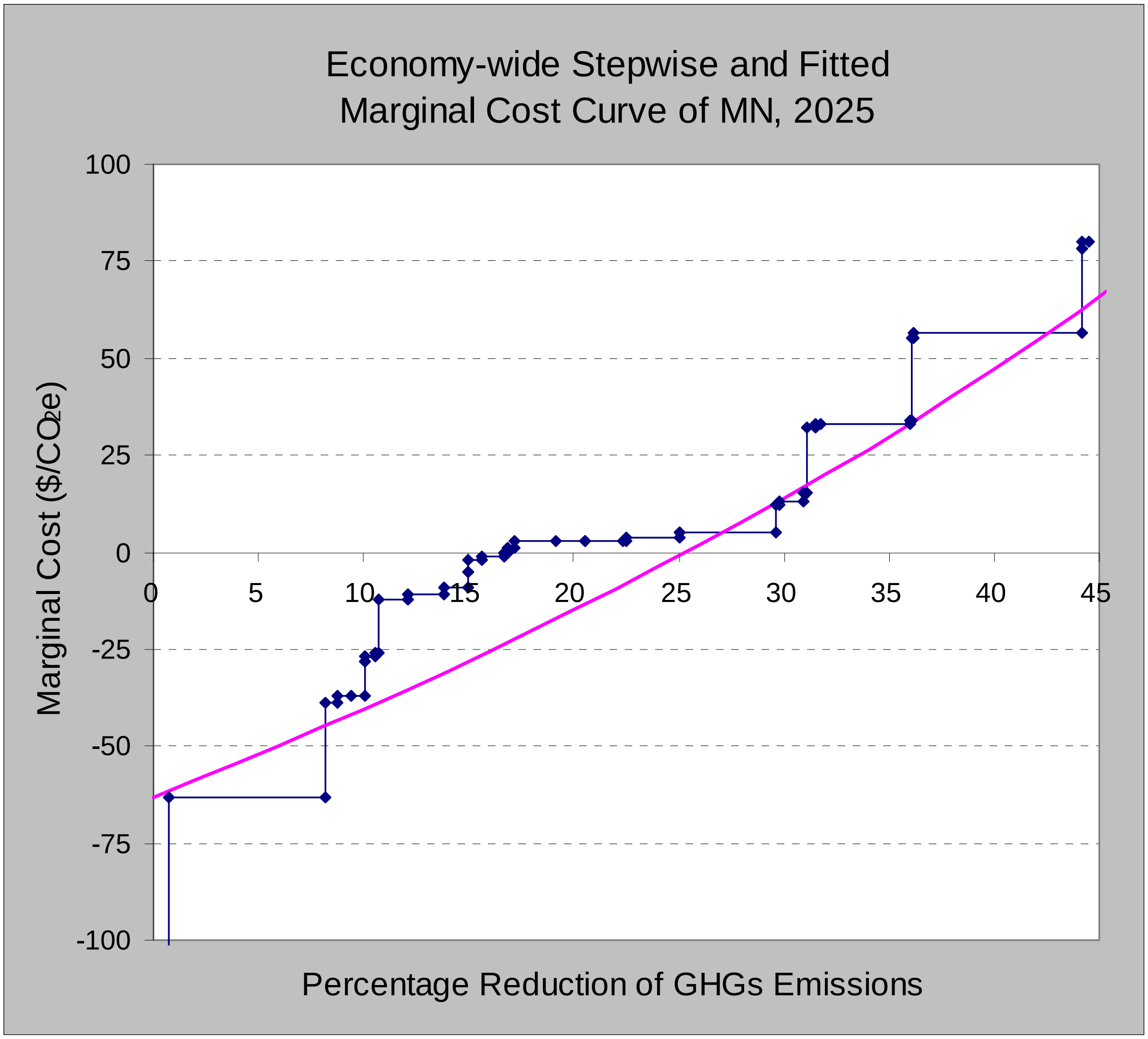
Table A-6. Reduction Potential and Cost/Saving of Individual Policy Option

Recom-mendation No.	Climate Mitigation Recommendation	Estimated 2025 Annual GHG Reduction Potential (MMtCO$_2$e)	Estimated Cost or Cost Savings per ton GHG Removed	GHG Reduction Potential as Percentage of 2025 Baseline Emissions	Cumulative GHG Reduction Potential
RCI-2	Improved Uniform Statewide Building Codes	0.005	–$576.00	0.00%	0.00%
RCI-10	Support Strong Federal Appliance Standards and Require High State Standards in the Absence of Federal Standards	1.4	–$124.00	0.71%	0.71%
RCI-1	Maximize Savings From the Utility Conservation Improvement Program (CIP)	14.7	–$63.20	7.44%	8.15%
TLU-6	Adopt California Clean Car Standards	1.16	–$39.00	0.59%	8.74%
AFW-1b	Agricultural Crop Management–B. Nutrient Management	1.3	–$37.00	0.66%	9.39%
RCI-6	Non-Utility Strategies and Incentives To Encourage Energy Efficiency and Reduce GHG Emissions	1.3	–$37.00	0.66%	10.05%
RCI-7	Conservation Improvement-Type Program for Propane and Fuel Oil Efficiency	0.05	–$28.00	0.03%	10.08%
RCI-3	Green Building Guidelines and Standards Based on *Architecture 2030*	0.94	–$27.00	0.48%	10.55%
ES-4	Transmission System Upgrading, Including Reducing Transmission Line and Distribution System Loss—Natural Gas Transmission and Distribution Upgrades	0.4	–$26.10	0.20%	10.75%
AFW-5b	Forestry Management Programs To Enhance GHG Benefits–B. Urban forestry	2.7	–$12.00	1.37%	12.12%
AFW-7b	Front-End Waste Management Technologies–B. Recycling	3.4	–$11.00	1.72%	13.84%
AFW-3a	In-State Liquid Biofuels Production–A. Ethanol Carbon Content	2.2	–$9.00	1.11%	14.95%
RCI-5	Program To Reduce Emissions of Non-Fuel, High-Global-Warming-Potential GHGs	0.05	–$5.00	0.03%	14.98%
AFW-1a	Agricultural Crop Management–A. Soil Carbon Management	1.3	–$2.00	0.66%	15.64%
TLU-5	Climate-Friendly Transportation Pricing / Pay-as-You-Drive	2.1	–$1.00	1.06%	16.70%
ES-1	Generation Performance Standard	0	$0.00	0.00%	16.70%
ES-6	Nuclear Power Support and Incentives—Installation of a Nuclear Power Station in 2020	0	NQ*	NQ*	16.70%

Recom-mendation No.	Climate Mitigation Recommendation	Estimated 2025 Annual GHG Reduction Potential ($MMtCO_2e$)	Estimated Cost or Cost Savings per ton GHG Removed	GHG Reduction Potential as Percentage of 2025 Baseline Emissions	Cumulative GHG Reduction Potential
ES-8	Advanced Fossil Fuel Technology Incentives, Support, or Requirements	0	NQ*	NQ*	16.70%
TLU-2	Expand Transit, Bicycle, and Pedestrian Infrastructure	0.3	$0.00	0.15%	16.85%
AFW-8a	End-of-Life Waste Management Practices–A. Landfilled Waste Methane	0.73	$1.00	0.37%	17.22%
AFW-4	Expanded Use of Biomass Feedstocks for Electricity, Heat, or Steam Production	3.8	$3.00	1.92%	19.14%
AFW-6	Forest Protection—Reduced Clearing and Conversion to Non-Forest Cover	2.7	$3.00	1.37%	20.51%
AFW-7a	Front-End Waste Management Technologies–A. Source Reduction	3.6	$3.00	1.82%	22.33%
AFW-7c	Front-End Waste Management Technologies–C. Composting	0.41	$3.00	0.21%	22.54%
RCI-4	Incentives and Resources To Promote Combined Heat and Power (CHP)	4.95	$3.80	2.50%	25.04%
AFW-3c	In-State Liquid Biofuels Production–C. Gasoline Displacement	9	$5.00	4.55%	29.60%
ES-3	Efficiency Improvements, Repowering and other Upgrades to Existing Plants—Biomass Co-firing	0.4	$12.00	0.20%	29.80%
AFW-5a	Forestry Management Programs To Enhance GHG Benefits–A. Forestation	2.2	$13.00	1.11%	30.91%
TLU-13	Reduce Maximum Speed Limits	0.4	$15.50	0.20%	31.11%
AFW-8c	End-of-Life Waste Management Practices–C. WTE Preprocessing	0.84	$32.00	0.43%	31.54%
AFW-2a	Land Use Management Approaches for Protection and Enrichment of Soil Carbon–A. Preserve Land	0.44	$33.00	0.22%	31.76%
AFW-5d	Forestry Management Programs to Enhance GHG Benefits–D. Restocking	8.4	$33.00	4.25%	36.01%
AFW-2b	Land Use Management Approaches for Protection and Enrichment of Soil Carbon–B. Reinvest in Minnesota–Clean Energy (RIM-CE)	0.19	$34.00	0.10%	36.11%
AFW-3b	In-State Liquid Biofuels Production–B. Fossil Diesel Displacement	0.19	$55.00	0.10%	36.20%
ES-5	Renewable and/or Environmental Portfolio Standard	15.7	$56.40	7.94%	44.15%
ES-12	Distributed Renewable Energy	0.023	$78.10	0.01%	44.16%
AFW-8b	End-of-Life Waste Management Practices–B. Residuals Management	0.63	$80.00	0.32%	44.48%

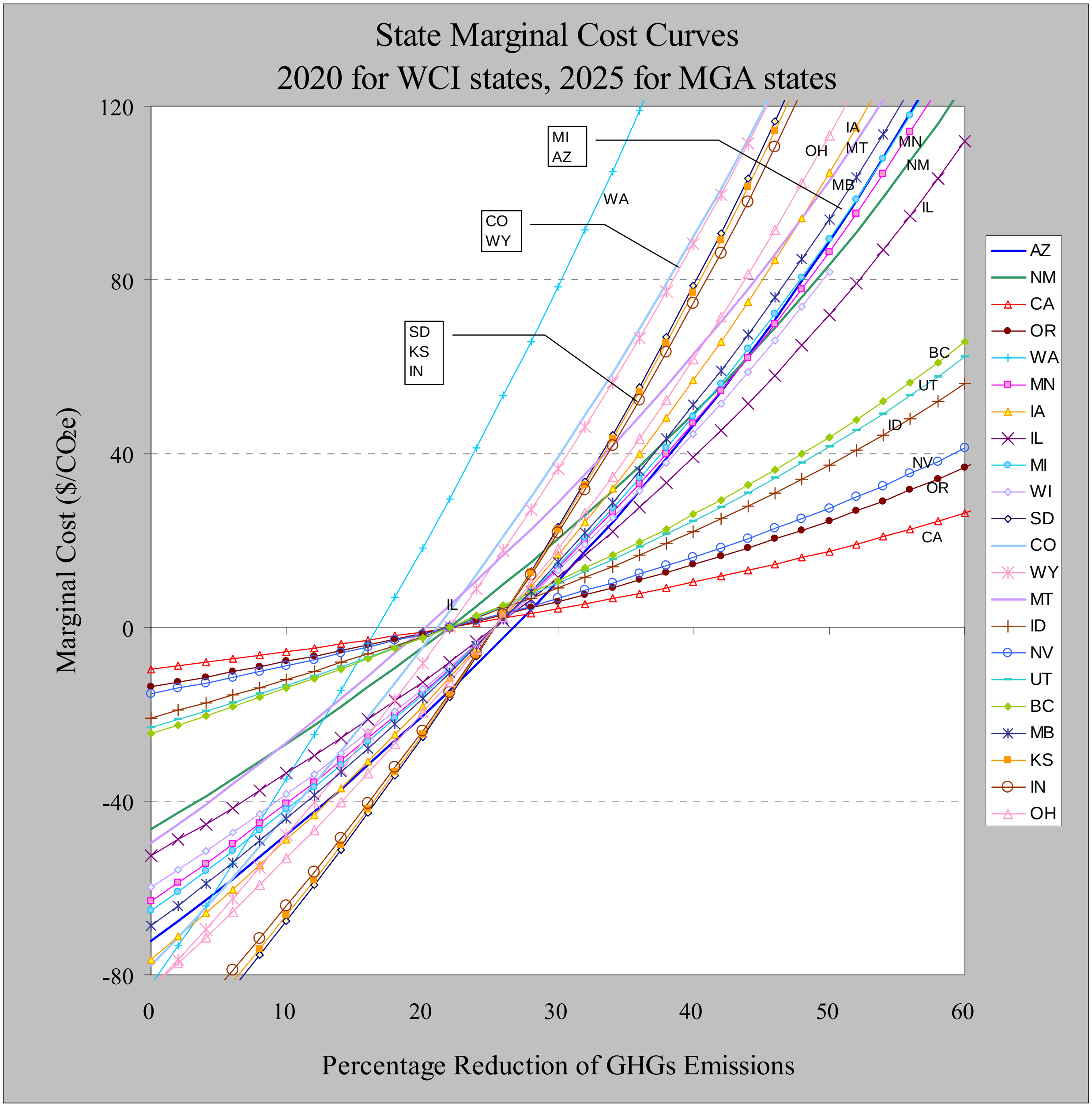
GHG = greenhouse gas; MMtCO$_2$e = million metric tons of carbon dioxide equivalent; RCI = Residential, Commercial, and Industrial; TLU = Transportation and Land Use; AFW = Agriculture, Forestry, and Waste Management; ES = Energy Supply; WTE = waste-to-energy; NQ* =

Figure A-1. Economy-wide Stepwise and Fitted Marginal Cost Curve of MN, 2025 (no RES and CIP in the Baseline)



$/tCO$_2$e = dollars per metric ton of carbon dioxide equivalent; GHG = greenhouse gas.

Figure A-2. State marginal cost curves, 2020 for WCI states, 2025 for MGA states



WCI = Western Climate Initiative; MGA = Midwestern Governors Association; $/CO$_2$e = dollars per carbon dioxide equivalent; GHG = greenhouse gas.

Note: Marginal cost curves of midwestern states are developed based on the Minnesota 2025 curve. Marginal cost curves of WCI states other than for AZ, CO, MT, and WA are developed based on the NM 2020 curve. In order to run simulations including both MGA and WCI states in 2025, we used 2020 marginal cost curves for WCI states for 2025. These marginal cost curves are presented for a range of mitigation levels, including those higher than required to meet the cap in 2025. We anticipate that there will be technology innovations in the future, i.e., the marginal cost curves will shift downward over time before higher levels of mitigation are necessary.

Sensitivity Analysis #2: both CIP and RES are in effect in the baseline condition.

Table A-7. (II-M1)—Economy-wide emission trading simulation among six midwestern states plus Manitoba in 2025 (million $ or otherwise specified)

	Before Trading	After Trading*				Permits Traded	Emission Reduction with Trading		Emission Reduction Goal
State	Mitigation Cost	Mitigation Cost	Trading Cost	Net Cost	Cost Saving	(MMtCO_2e)	(MMtCO_2e)	(percent from BAU)	(percent from BAU)
IA	–$478	–$945	$361	–$584	$106	7.85	47.16	37.42	43.65
IL	–$1,581	–$1,062	–$599	–$1,661	$80	–13.04	136.07	42.23	38.18
KS	–$621	–$1,419	$510	–$909	$288	11.09	41.71	34.48	43.65
MI	–$1,663	–$1,532	–$137	–$1,669	$6	–2.99	107.22	39.27	38.18
MN	$249	$140	$104	$245	$5	2.27	52.94	32.33	33.72
WI	–$915	–$762	–$166	–$929	$14	–3.62	66.14	40.39	38.18
MB	–$178	–$128	–$72	–$200	$22	–1.57	7.96	38.64	31.02
Total	**–$5,187**	**–$5,707**	**$0**	**–$5,707**	**$520**	**21.22**[†]	**459.21**	**38.58**	**38.58**

MMtCO_2e = million metric tons of carbon dioxide equivalent; BAU = business as usual.

* Permit Price = $45.95/t$CO_2$e. This is the price of the last permit sold, which is also equal to the price of the last ton of CO_2e mitigated (its *marginal* mitigation cost). It is the same for each state for a given case. The *average* mitigation cost per unit of CO_2e in this simulation differs for each state. For Minnesota, for example, it is $2.65/t$CO_2$e. Please note that the average mitigation cost is related to mitigation level of a state which, for this case, is 32.33% below the baseline level in 2025 for Minnesota. Multiplying the average mitigation cost by the number of tons of CO_2 mitigated will equal the *total* mitigation cost for each state.

† Represents number of permits bought or sold.

Table A-8. (II-M2)—Economy-wide emission trading simulation among nine midwestern states plus Manitoba in 2025 (million $ or otherwise specified)

	Before Trading	After Trading*				Permits Traded	Emission Reduction After Trading		Emission Reduction Cap
State	**Mitigation Cost**	**Mitigation Cost**	**Trading Cost**	**Net Cost**	**Cost Saving**	**(MMtCO$_2$e)**	**(MMtCO$_2$e)**	**(Percent From BAU)**	**(Percent From BAU)**
IA	–$478	–$876	$326	–$550	$72	6.43	48.59	38.55	43.65
IL	–$1,581	–$826	–$909	–$1,735	$154	–17.92	140.95	43.74	38.18
KS	–$621	–$1,367	$509	–$858	$238	10.03	42.77	35.36	43.65
MI	–$1,663	–$1,363	–$329	–$1,692	$29	–6.49	110.72	40.56	38.18
MN	$249	$261	–$12	$249	$0	–0.24	55.45	33.86	33.72
WI	–$915	–$653	–$298	–$951	$36	–5.87	68.39	41.77	38.18
MB	–$178	–$116	–$93	–$208	$30	–1.83	8.22	39.88	31.02
IN	–$2,954	–$3,410	$402	–$3,007	$54	7.93	112.89	35.67	38.18
OH	–$3,018	–$3,132	$111	–$3,021	$3	2.19	146.82	37.62	38.18
SD	–$64	–$561	$293	–$268	$205	5.77	16.98	35.18	47.13
Total	**–$11,223**	**–$12,042**	**$0**	**–$12,042**	**$819**	**32.34**[†]	**751.78**	**38.65**	**38.65**

MMtCO$_2$e = million metric tons of carbon dioxide equivalent; BAU = business as usual.

* Permit Price = $50.72/tCO$_2$e. This is the price of the last permit sold, which is also equal to the price of the last ton of CO$_2$e mitigated (its *marginal* mitigation cost). It is the same for each state for a given case. The *average* mitigation cost per unit of CO$_2$e in this simulation differs for each state. For Minnesota, for example, it is $4.71/tCO$_2$e. Please note that the average mitigation cost is related to mitigation level of a state which, for this case, is 33.86% below the baseline level in 2025 for Minnesota. Multiplying the average mitigation cost by the number of tons of CO$_2$ mitigated will equal the *total* mitigation cost for each state.

† Represents number of permits bought or sold.

Table A-9. (II-M1W1)—Economy-wide emission trading simulation among six midwestern states, six western states, and two Canadian provinces in 2025 (million $ or otherwise specified)

	Before Trading	After Trading*				Permits Traded	Emission Reduction After Trading		Emission Reduction Cap
State	**Mitigation Cost**	**Mitigation Cost**	**Trading Cost**	**Net Cost**	**Cost Saving**	**($MMtCO_2e$)**	**($MMtCO_2e$)**	**(Percent From BAU)**	**(Percent From BAU)**
AZ	$2,954	–$1,592	$1,733	$140	$2,814	49.57	70.01	36.96	63.14
CA	$459	$3,709	–$4,656	–$946	$1,405	–133.21	439.40	67.81	47.25
NM	$421	–$305	$458	$153	$269	13.11	35.07	35.24	48.41
OR	$89	$383	–$369	$15	$74	–10.55	53.87	58.63	47.15
UT	$528	$145	$314	$459	$69	8.97	49.69	46.37	54.74
WA	$3,666	–$798	$1,248	$450	$3,217	35.70	30.35	22.91	49.86
BC	$29	$84	–$58	$26	$3	–1.65	36.73	45.26	43.22
IA	–$478	–$1,082	$393	–$689	$211	11.25	43.77	34.73	43.65
IL	–$1,581	–$1,537	–$45	–$1,581	$1	–1.28	124.31	38.58	38.18
KS	–$621	–$1,520	$475	–$1,045	$424	13.60	39.20	32.41	43.65
MI	–$1,663	–$1,871	$189	–$1,682	$19	5.40	98.83	36.20	38.18
MN	$249	–$103	$290	$187	$63	8.29	46.93	28.66	33.72
WI	–$915	–$980	$62	–$918	$3	1.77	60.75	37.10	38.18
MB	–$178	–$152	–$34	–$186	$8	–0.96	7.36	35.70	31.02
Total	**$2,959**	**–$5,619**	**$0**	**–$5,619**	**$8,578**	**147.65**[†]	**1,136.28**	**44.74**	**44.74**

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent; BAU = business as usual.

* Permit Price = $34.95/$tCO_2e$. This is the price of the last permit sold, which is also equal to the price of the last ton of CO_2e mitigated (its *marginal* mitigation cost). It is the same for each state for a given case. The *average* mitigation cost per unit of CO_2e in this simulation differs for each state. For Minnesota, for example, it is –$2.19/$tCO_2e$. Please note that the average mitigation cost is related to mitigation level of a state which, for this case, is 28.66% below the baseline level in 2025 for Minnesota. Multiplying the average mitigation cost by the number of tons of CO_2 mitigated will equal the *total* mitigation cost for each state.

† Represents number of permits bought or sold.

Table A-10. (II-M2W2)—Economy-wide emission trading simulation among nine midwestern states, eleven western states, and two Canadian provinces in 2020 (million $ or otherwise specified)

	Before Trading	After Trading*				Permits Traded	Emission Reduction After Trading		Emission Reduction Cap
State	Mitigation Cost	Mitigation Cost	Trading Cost	Net Cost	Cost Saving	(MMtCO$_2$e)	(MMtCO$_2$e)	(percent from BAU)	(percent from BAU)
AZ	$2,954	–$1,471	$1,913	$442	$2,512	46.38	73.20	38.65	63.14
CA	$459	$4,879	–$6,764	–$1,885	$2,343	–163.98	470.17	72.55	47.25
NM	$421	–$224	$453	$229	$193	10.98	37.20	37.38	48.41
OR	$89	$540	–$604	–$65	$154	–14.65	57.98	63.10	47.15
UT	$528	$288	$215	$503	$24	5.22	53.44	49.87	54.74
WA	$3,666	–$744	$1,414	$670	$2,996	34.28	31.77	23.98	49.86
BC	$29	$189	–$182	$7	$22	–4.40	39.48	48.64	43.22
CO	$1,611	–$1,067	$1,229	$162	$1,449	29.80	48.61	30.43	49.08
ID	$26	$156	–$156	$0	$26	–3.78	24.37	52.23	44.13
MT	$33	–$108	$112	$4	$29	2.71	14.65	33.84	40.10
NV	$354	$429	–$78	$351	$3	–1.89	49.21	60.02	57.72
WY	$506	–$575	$518	–$57	$563	12.57	23.13	30.98	47.82
IA	–$478	–$1,007	$383	–$624	$146	9.29	45.73	36.28	43.65
IL	–$1,581	–$1,277	–$334	–$1,611	$30	–8.10	131.13	40.69	38.18
KS	–$621	–$1,465	$501	–$964	$343	12.15	40.65	33.60	43.65
MI	–$1,663	–$1,686	$23	–$1,663	$0	0.55	103.68	37.98	38.18
MN	$249	$30	$198	$228	$22	4.81	50.41	30.79	33.72
WI	–$915	–$861	–$56	–$917	$2	–1.35	63.87	39.01	38.18
MB	–$178	–$139	–$54	–$193	$15	–1.31	7.71	37.40	31.02
IN	–$2,954	–$3,673	$563	–$3,110	$156	13.65	107.17	33.87	38.18
OH	–$3,018	–$3,513	$432	–$3,081	$63	10.47	138.53	35.50	38.18
SD	–$64	–$599	$272	–$327	$263	6.60	16.15	33.45	47.13
Total	**–$546**	**–$11,900**	**$0**	**–$11,900**	**$11,354**	**199.46**[†]	**1,628.23**	**43.99**	**43.99**

MMtCO$_2$e = million metric tons of carbon dioxide equivalent; BAU = business as usual.

* Permit Price = $41.25/tCO$_2$e. This is the price of the last permit sold, which is also equal to the price of the last ton of CO$_2$e mitigated (its *marginal* mitigation cost). It is the same for each state for a given case. The *average* mitigation cost per unit of CO$_2$e in this simulation differs for each state. For Minnesota, for example, it is $0.59/tCO$_2$e. Please note that the average mitigation cost is related to mitigation level of a state which, for this case, is 30.79% below the baseline level in 2020 for Minnesota. Multiplying the average mitigation cost by the number of tons of CO$_2$ mitigated will equal the *total* mitigation cost for each state.

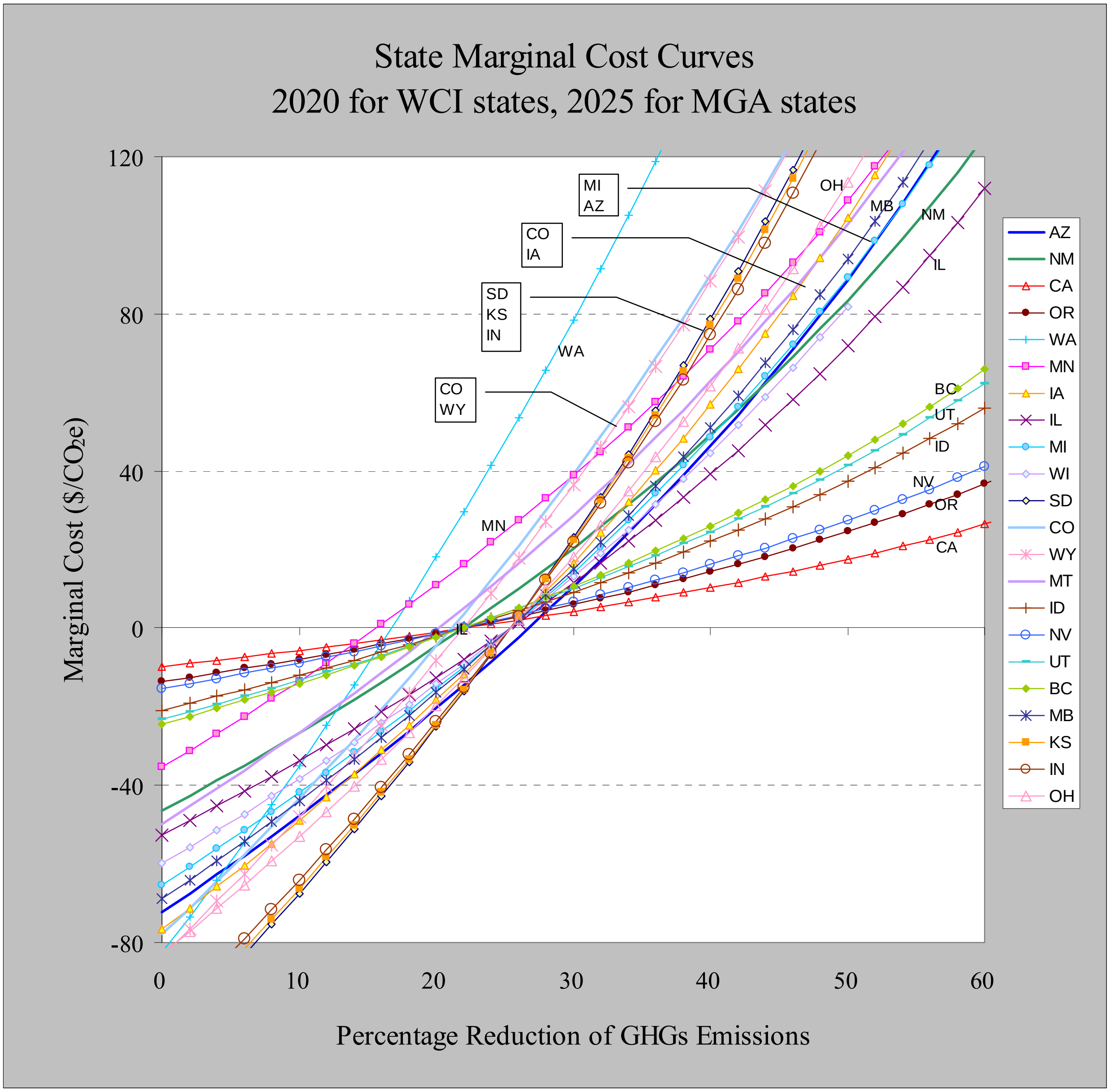
[†] Represents number of permits bought or sold.

Table A-11. Summary Data Table

State	Cap: 30% Below 2005 Emissions in 2025 ($MMtCO_2e$)	2025 BAU Gross Emissions (Consumption-based) ($MMtCO_2e$)	GHG Mitigation Goal in 2025 (relative to BAU emissions)	Autarkic Marginal Mitigation Cost ($\$/tCO_2e$)	Gross State Product in 2025 (million $ 2000)
AZ	69.8	189.4	63.14%	$159.6	$481,628
CA	341.8	648.0	47.25%	$15.5	$2,923,222
NM	51.3	99.5	48.41%	$77.6	$94,564
OR	48.6	91.9	47.15%	$21.5	$297,081
UT	48.5	107.2	54.74%	$50.8	$204,725
WA	66.4	132.5	49.86%	$229.0	$471,781
BC	46.1	81.2	43.22%	$31.3	$146,610
CO	81.3	159.8	49.08%	$143.8	$563,455
ID	26.1	46.7	44.13%	$28.1	$98,835
MT	25.9	43.3	40.10%	$63.1	$41,520
NV	34.7	82.0	57.72%	$37.8	$236,707
WY	39.0	74.7	47.82%	$135.2	$39,577
IA	71.0	126.0	43.65%	$73.4	$206,621
IL	199.2	322.2	38.18%	$33.8	$768,315
KS	68.2	121.0	43.65%	$99.2	$146,593
MI	168.8	273.0	38.18%	$42.0	$524,088
MN	108.5	163.8	33.72%	$50.3	$392,084
WI	101.2	163.8	38.18%	$38.5	$342,743
MB	14.2	20.6	31.02%	$18.5	$37,581
IN	195.6	316.5	38.18%	$64.3	$396,501
OH	241.3	390.3	38.18%	$53.3	$590,200
SD	25.5	48.3	47.13%	$124.2	$57,361
Total	**2,073.1**	**3,701.3**	**43.99%**		**$9,061,793**

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent; BAU = business as usual; $\$/tCO_2e$ = dollars per metric ton of carbon dioxide equivalent.

Figure A-3. State marginal cost curves, 2020 for WCI states, 2025 for MGA states



WCI = Western Climate Initiative; MGA = Midwestern Governors Association; $/CO$_2$e = dollars per carbon dioxide equivalent; GHG = greenhouse gas.

Note: Marginal cost curves of midwestern states are developed based on the Minnesota 2025 curve assuming no CIP and RES in effect in the baseline condition. The Minnesota 2025 curve shown in this figure assumes that both CIP and RES are in effect in the baseline condition. Marginal cost curves of WCI states other than for AZ, CO, MT, and WA are developed based on the NM 2020 curve. In order to run simulations including both MGA and WCI states in 2025, we used 2020 marginal cost curves for WCI states for 2025. These marginal cost curves are presented for a range of mitigation levels, including those higher than required to meet the cap in 2025. We anticipate that there will be technology innovations in the future, i.e., the marginal cost curves will shift downward over time before higher levels of mitigation are necessary.

Sensitivity Analysis #3: RES is in effect, but no CIP in the baseline condition

Table A-12. (III-M1)—Economy-wide emission trading simulation among six midwestern states plus Manitoba in 2025 (million $ or otherwise specified)

	Before Trading	**After Trading***				**Permits Traded**	**Emission Reduction with Trading**		**Emission Reduction Goal**
State	**Mitigation Cost**	**Mitigation Cost**	**Trading Cost**	**Net Cost**	**Cost Saving**	**(MMtCO$_2$e)**	**(MMtCO$_2$e)**	**(Percent From BAU)**	**(Percent From BAU)**
IA	–$478	–$935	$357	–$579	$100	7.65	47.37	37.58	43.65
IL	–$1,581	–$1,029	–$641	–$1,670	$89	–13.75	136.78	42.45	38.18
KS	–$621	–$1,411	$510	–$901	$280	10.94	41.86	34.61	43.65
MI	–$1,663	–$1,508	–$163	–$1,671	$8	–3.50	107.73	39.46	38.18
MN	–$822	–$1,039	$197	–$842	$20	4.22	67.35	37.40	39.74
WI	–$915	–$747	–$184	–$931	$16	–3.95	66.47	40.59	38.18
MB	–$178	–$126	–$75	–$201	$23	–1.61	8.00	38.82	31.02
Total	**–$6,258**	**–$6,796**	**$0**	**–$6,796**	**$537**	**22.81**[†]	**475.57**	**39.41**	**39.41**

MMtCO$_2$e = million metric tons of carbon dioxide equivalent; BAU = business as usual.

* Permit Price = $46.64/tCO$_2$e. This is the price of the last permit sold, which is also equal to the price of the last ton of CO$_2$e mitigated (its *marginal* mitigation cost). It is the same for each state for a given case. The *average* mitigation cost per unit of CO$_2$e in this simulation differs for each state. For Minnesota, for example, it is –$15.42/tCO$_2$e. Please note that the average mitigation cost is related to mitigation level of a state which, for this case, is 37.40% below the baseline level in 2025 for Minnesota. Multiplying the average mitigation cost by the number of tons of CO$_2$ mitigated will equal the *total* mitigation cost for each state.

[†] Represents number of permits bought or sold.

Table A-13. (II-M2)—Economy-wide emission trading simulation among nine midwestern states plus Manitoba in 2025 (million $ or otherwise specified)

	Before Trading	After Trading*				Permits Traded	Emission Reduction After Trading		Emission Reduction Cap
State	**Mitigation Cost**	**Mitigation Cost**	**Trading Cost**	**Net Cost**	**Cost Saving**	**($MMtCO_2e$)**	**($MMtCO_2e$)**	**(percent from BAU)**	**(percent from BAU)**
IA	–$478	–$868	$321	–$546	$68	6.26	48.75	38.68	43.65
IL	–$1,581	–$798	–$947	–$1,745	$164	–18.47	141.50	43.91	38.18
KS	–$621	–$1,361	$508	–$853	$232	9.91	42.89	35.46	43.65
MI	–$1,663	–$1,342	–$353	–$1,696	$32	–6.89	111.12	40.70	38.18
MN	–$822	–$936	$109	–$827	$5	2.12	69.45	38.56	39.74
WI	–$915	–$640	–$314	–$955	$40	–6.13	68.65	41.92	38.18
MB	–$178	–$114	–$95	–$209	$31	–1.85	8.25	40.02	31.02
IN	–$2,954	–$3,393	$390	–$3,003	$49	7.61	113.21	35.78	38.18
OH	–$3,018	–$3,108	$88	–$3,020	$2	1.72	147.29	37.74	38.18
SD	–$64	–$558	$293	–$265	$202	5.72	17.03	35.28	47.13
Total	**–$12,294**	**–$13,119**	**$0**	**–$13,119**	**$825**	**33.34**†	**768.14**	**39.16**	**39.16**

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent; BAU = business as usual.

* Permit Price = $51.27/$tCO_2e$. This is the price of the last permit sold, which is also equal to the price of the last ton of CO_2e mitigated (its *marginal* mitigation cost). It is the same for each state for a given case. The *average* mitigation cost per unit of CO_2e in this simulation differs for each state. For Minnesota, for example, it is –$13.48/$tCO_2e$. Please note that the average mitigation cost is related to mitigation level of a state which, for this case, is 38.56% below the baseline level in 2025 for Minnesota. Multiplying the average mitigation cost by the number of tons of CO_2 mitigated will equal the *total* mitigation cost for each state.

† Represents number of permits bought or sold.

Table A-14. (II-M1W1)—Economy-wide emission trading simulation among six midwestern states, six western states, and two Canadian provinces in 2025 (million dollars or otherwise specified)

	Before Trading	**After Trading***				**Permits Traded**	**Emission Reduction After Trading**		**Emission Reduction Cap**
State	**Mitigation Cost**	**Mitigation Cost**	**Trading Cost**	**Net Cost**	**Cost Saving**	**(MMtCO_2e)**	**(MMtCO_2e)**	**(Percent From BAU)**	**(Percent From BAU)**
AZ	$2,954	–$1,590	$1,736	$146	$2,808	49.51	70.07	37.00	63.14
CA	$459	$3,732	–$4,695	–$963	$1,421	–133.86	440.05	67.91	47.25
NM	$421	–$304	$458	$154	$267	13.07	35.12	35.28	48.41
OR	$89	$386	–$373	$13	$75	–10.63	53.96	58.72	47.15
UT	$528	$148	$312	$460	$68	8.90	49.76	46.44	54.74
WA	$3,666	–$797	$1,251	$454	$3,212	35.67	30.38	22.93	49.86
BC	$29	$86	–$60	$26	$3	–1.71	36.79	45.33	43.22
IA	–$478	–$1,081	$393	–$688	$209	11.21	43.81	34.76	43.65
IL	–$1,581	–$1,532	–$50	–$1,582	$1	–1.41	124.44	38.62	38.18
KS	–$621	–$1,519	$476	–$1,043	$422	13.57	39.23	32.43	43.65
MI	–$1,663	–$1,867	$186	–$1,681	$18	5.30	98.93	36.24	38.18
MN	–$822	–$1,261	$339	–$922	$100	9.65	61.92	34.38	39.74
WI	–$915	–$978	$60	–$918	$3	1.71	60.81	37.14	38.18
MB	–$178	–$152	–$34	–$186	$8	–0.97	7.36	35.73	31.02
Total	**$1,888**	**–$6,728**	**$0**	**–$6,728**	**$8,616**	**148.59**†	**1,152.64**	**45.09**	**45.09**

MMtCO_2e = million metric tons of carbon dioxide equivalent; BAU = business as usual.

* Permit Price = $35.07/t$CO_2$e. This is the price of the last permit sold, which is also equal to the price of the last ton of CO_2e mitigated (its *marginal* mitigation cost). It is the same for each state for a given case. The *average* mitigation cost per unit of CO_2e in this simulation differs for each state. For Minnesota, for example, it is –$20.36/t$CO_2$e. Please note that the average mitigation cost is related to mitigation level of a state which, for this case, is 34.38% below the baseline level in 2025 for Minnesota. Multiplying the average mitigation cost by the number of tons of CO_2 mitigated will equal the *total* mitigation cost for each state.

† Represents number of permits bought or sold.

Table A-15. (II-M2W2)—Economy-wide emission trading simulation among nine midwestern states, eleven western states, and two Canadian provinces in 2020 (million $ or otherwise specified)

	Before Trading	After Trading*				Permits Traded	Emission Reduction After Trading		Emission Reduction Cap
State	Mitigation Cost	Mitigation Cost	Trading Cost	Net Cost	Cost Saving	(MMtCO$_2$e)	(MMtCO$_2$e)	(Percent From BAU)	(Percent From BAU)
AZ	$2,954	–$1,468	$1,917	$449	$2,505	46.31	73.27	38.69	63.14
CA	$459	$4,905	–$6,813	–$1,908	$2,366	–164.61	470.81	72.65	47.25
NM	$421	–$222	$452	$230	$191	10.93	37.25	37.43	48.41
OR	$89	$543	–$610	–$67	$156	–14.74	58.07	63.19	47.15
UT	$528	$292	$213	$504	$24	5.14	53.52	49.95	54.74
WA	$3,666	–$743	$1,418	$675	$2,991	34.25	31.80	24.00	49.86
BC	$29	$191	–$185	$6	$23	–4.46	39.54	48.72	43.22
CO	$1,611	–$1,066	$1,231	$166	$1,445	29.75	48.65	30.46	49.08
ID	$26	$158	–$158	$0	$26	–3.81	24.41	52.31	44.13
MT	$33	–$107	$111	$4	$29	2.69	14.66	33.88	40.10
NV	$354	$432	–$81	$351	$4	–1.96	49.28	60.11	57.72
WY	$506	–$574	$519	–$55	$561	12.55	23.15	31.01	47.82
IA	–$478	–$1,006	$383	–$623	$145	9.24	45.77	36.32	43.65
IL	–$1,581	–$1,271	–$341	–$1,612	$32	–8.25	131.28	40.74	38.18
KS	–$621	–$1,463	$502	–$962	$341	12.12	40.68	33.63	43.65
MI	–$1,663	–$1,682	$18	–$1,663	$0	0.44	103.79	38.02	38.18
MN	–$822	–$1,146	$276	–$870	$48	6.66	64.92	36.04	39.74
WI	–$915	–$858	–$59	–$917	$2	–1.42	63.94	39.05	38.18
MB	–$178	–$139	–$55	–$193	$15	–1.32	7.72	37.44	31.02
IN	–$2,954	–$3,669	$562	–$3,108	$154	13.57	107.25	33.89	38.18
OH	–$3,018	–$3,508	$428	–$3,079	$61	10.35	138.66	35.53	38.18
SD	–$64	–$599	$273	–$326	$262	6.59	16.16	33.48	47.13
Total	**–$1,618**	**–$12,999**	**$0**	**–$12,999**	**$11,381**	**200.59**[†]	**1,644.58**	**44.24**	**44.24**

MMtCO$_2$e = million metric tons of carbon dioxide equivalent; BAU = business as usual.

* Permit Price = $41.39/tCO$_2$e. This is the price of the last permit sold, which is also equal to the price of the last ton of CO$_2$e mitigated (its *marginal* mitigation cost). It is the same for each state for a given case. The *average* mitigation cost per unit of CO$_2$e in this simulation differs for each state. For Minnesota, for example, it is –$17.65/tCO$_2$e. Please note that the average mitigation cost is related to mitigation level of a state, which for this case is 36.04% below the baseline level in 2020 for Minnesota. Multiplying the average mitigation cost by the number of tons of CO$_2$ mitigated will equal the *total* mitigation cost for each state.

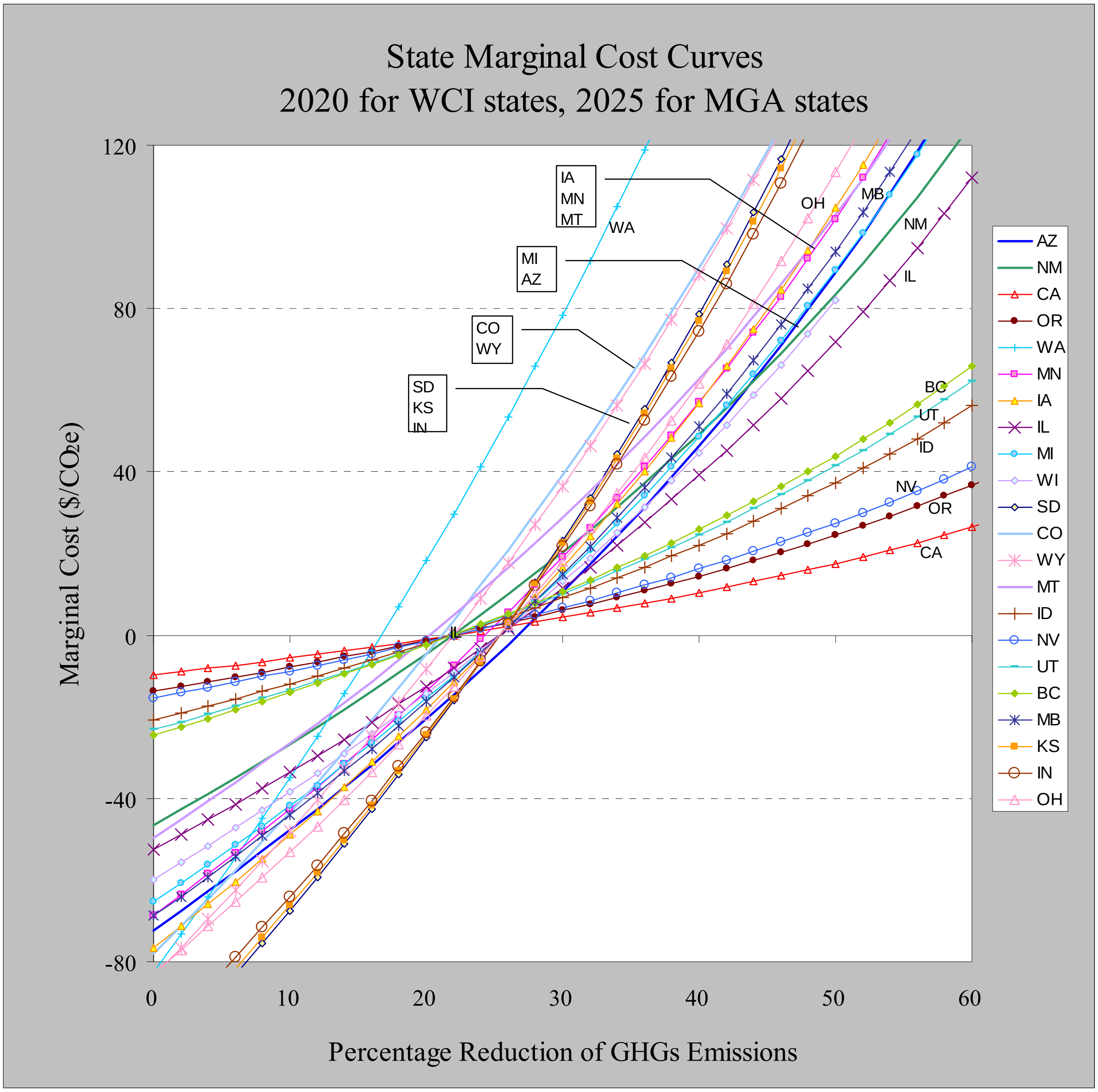
[†] Represents number of permits bought or sold.

Table A-16. Summary Data Table

State	Cap: 30% Below 2005 Emissions in 2025 ($MMtCO_2e$)	2025 BAU Gross Emissions (Consumption-Based) ($MMtCO_2e$)	GHG Mitigation Goal in 2025 (Relative to BAU Emissions)	Autarkic Marginal Mitigation Cost ($\$/tCO_2e$)	Gross State Product in 2025 (Million $ 2000)
AZ	69.8	189.4	63.14%	$159.6	$481,628
CA	341.8	648.0	47.25%	$15.5	$2,923,222
NM	51.3	99.5	48.41%	$77.6	$94,564
OR	48.6	91.9	47.15%	$21.5	$297,081
UT	48.5	107.2	54.74%	$50.8	$204,725
WA	66.4	132.5	49.86%	$229.0	$471,781
BC	46.1	81.2	43.22%	$31.3	$146,610
CO	81.3	159.8	49.08%	$143.8	$563,455
ID	26.1	46.7	44.13%	$28.1	$98,835
MT	25.9	43.3	40.10%	$63.1	$41,520
NV	34.7	82.0	57.72%	$37.8	$236,707
WY	39.0	74.7	47.82%	$135.2	$39,577
IA	71.0	126.0	43.65%	$73.4	$206,621
IL	199.2	322.2	38.18%	$33.8	$768,315
KS	68.2	121.0	43.65%	$99.2	$146,593
MI	168.8	273.0	38.18%	$42.0	$524,088
MN	108.5	180.1	39.74%	$56.0	$392,084
WI	101.2	163.8	38.18%	$38.5	$342,743
MB	14.2	20.6	31.02%	$18.5	$37,581
IN	195.6	316.5	38.18%	$64.3	$396,501
OH	241.3	390.3	38.18%	$53.3	$590,200
SD	25.5	48.3	47.13%	$124.2	$57,361
Total	**2,073.1**	**3,717.7**	**44.24%**		**$9,061,793**

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent; BAU = business as usual.

Figure A-4. State marginal cost curves, 2020 for WCI states, 2025 for MGA states



WCI = Western Climate Initiative; MGA = Midwestern Governors Association; $/CO$_2$e = dollars per carbon dioxide equivalent; GHG = greenhouse gas.

Note: Marginal cost curves of midwestern states are developed based on the Minnesota 2025 curve assuming no CIP and RES in effect in the baseline condition. The Minnesota 2025 curve shown in this figure assumes that RES is in effect in the baseline condition, but no CIP in the baseline. Marginal cost curves of WCI states other than for AZ, CO, MT, and WA are developed based on the NM 2020 curve. In order to run simulations including both MGA and WCI states in year 2025, we used 2020 marginal cost curves for WCI states for 2025. These marginal cost curves are presented for a range of mitigation levels, including those higher than required to meet the cap in 2025. We anticipate that there will be technology innovations in the future, i.e., the marginal cost curves will shift downward over time before higher levels of mitigation are necessary.

Auction Case

- In an auction case, we assume there would be no permit trading among states.
- According to the Coase Theorem, in equilibrium, each state will choose to mitigate the same level of emissions as it would in a permit trading market.
- Each state would buy its total allowances from the auctioneer.
- The auction price would be the same level as the equilibrium price in a permit trading market.
- The auction revenues can be used ("recycled") to fund research and development in clean energy technologies, subsidize business expenditures on mitigation, and reduce various taxes. However, the impacts of recycling those revenues are not included in the simulation below.

Table A-17. An auction case among MGA partners (assume no RES/CIP in the baseline)

State	Total BAU Emissions in 2025 (MMtCO$_2$)	Emission Reduction Undertaken by the State* (Percent From BAU)	Emission Reduction Undertaken by the State* (MMtCO$_2$)	Emission Allowances Bought From Auctioneer	Auction Cost (billion $)†	Mitigation Cost (billion $)	Total Cost (billion $)
IA	126.04	38.01	47.91	78.13	$3.79	–$0.91	$2.88
IL	322.24	43.02	138.64	183.60	$8.90	–$0.94	$7.95
KS	120.96	34.94	42.27	78.69	$3.81	–$1.39	$2.42
MI	273.00	39.95	109.06	163.94	$7.94	–$1.45	$6.50
MN	197.65	40.38	79.82	117.83	$5.71	–$0.97	$4.74
WI	163.75	41.11	67.32	96.43	$4.67	–$0.71	$3.97
MB	20.61	39.29	8.10	12.51	$0.61	–$0.12	$0.48
Total	**1,224.25**	**40.28**	**493.11**	**731.14**	**$35.42**	**–$6.49**	**$28.93**

BAU = business as usual; MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

* In equilibrium, each state will choose to mitigate the same level of emissions as they would do in a permit trading market.

† The auction price would be the same level ($48.45/tCO$_2$e) as the equilibrium price in a permit trading market.

Table A-18. An auction case among MGA partners (assume both RES and CIP are in effect in the baseline)

State	Total BAU Emissions in 2025 (MMtCO$_2$)	Emission Reduction Undertaken by the State*		Emission Allowances Bought From Auctioneer	Auction Cost (billion $)†	Mitigation Cost (billion $)	Total Cost (billion $)
		(Percent From BAU)	(MMtCO$_2$)				
IA	126.04	37.42	47.16	78.88	$3.62	–$0.94	$2.68
IL	322.24	42.23	136.07	186.17	$8.56	–$1.06	$7.49
KS	120.96	34.48	41.71	79.25	$3.64	–$1.42	$2.22
MI	273.00	39.27	107.22	165.78	$7.62	–$1.53	$6.09
MN	163.75	32.33	52.94	110.81	$5.09	$0.14	$5.23
WI	163.75	40.39	66.14	97.61	$4.49	–$0.76	$3.72
MB	20.61	38.64	7.96	12.65	$0.58	–$0.13	$0.45
Total	**1,190.35**	**38.58**	**459.21**	**731.14**	**$33.60**	**–$5.71**	**$27.89**

BAU = business as usual; MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

* In equilibrium, each state will choose to mitigate the same level of emissions as they would do in a permit trading market.

† The auction price would be the same level ($45.95/tCO$_2$e) as the equilibrium price in a permit trading market.

Table A-19. An auction case among MGA partners (assume only RES is in effect in the baseline)

State	Total BAU Emissions in 2025 (MMtCO$_2$)	Emission Reduction Undertaken by the State*		Emission Allowances Bought From Auctioneer	Auction Cost (billion $)†	Mitigation Cost (billion $)	Total Cost (billion $)
		(Percent From BAU)	(MMtCO$_2$)				
IA	126.04	37.58	47.37	78.67	$3.67	–$0.94	$2.73
IL	322.24	42.45	136.78	185.46	$8.65	–$1.03	$7.62
KS	120.96	34.61	41.86	79.10	$3.69	–$.41	$2.28
MI	273.00	39.46	107.73	165.27	$7.71	–$1.51	$6.20
MN	180.11	37.40	67.35	112.76	$5.26	–$1.04	$4.22
WI	163.75	40.59	66.47	97.28	$4.54	–$0.75	$3.79
MB	20.61	38.82	8.00	12.61	$0.59	–$0.13	$0.46
Total	**1,206.71**	**39.41**	**475.57**	**731.14**	**$34.10**	**–$6.80**	**$27.31**

BAU = business as usual; MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

* In equilibrium, each state will choose to mitigate the same level of emissions as they would do in a permit trading market.

† The auction price would be the same level ($46.64/tCO$_2$e) as the equilibrium price in a permit trading market.

Minnesota-Only Cap-and-Trade Scenario

GHG mitigation policy options are proposed and designed for Minnesota in the following four sectoral categories: (1) ES, Energy Supply, (2) RCI, Residential, Commercial, and Industrial, (3) TLU, Transportation and Land Use, and (4) AFW, Agriculture, Forestry, and Waste Management. Table A-19 presents a list of options that currently have quantified mitigation potential and cost information. In this section, we study a cap-and-trade program between major sectors in Minnesota. In the last column of Table A-19, we classify the options into four major sectors: (1) Power Sector, (2) Transportation Sector, (3) Sequestration, and 4) Other (including Industrial, Commercial, Agriculture, Forestry, and Small Power Generation).

Table A-20. Minnesota Mitigation Policy Recommendations List

Recom-mendation No.	Climate Mitigation Recommendation	Estimated 2025 Annual GHG Reduction Potential (MMtCO$_2$e)	Estimated Cost or Cost Savings per ton GHG Removed	Sector
AFW-1a	Agricultural Crop Management—A. Soil Carbon Management	1.3	–$2.00	Sequestration
AFW-1b	Agricultural Crop Management—B. Nutrient Management	1.3	–$37.00	Sequestration
AFW-2a	Land Use Management Approaches for Protection and Enrichment of Soil Carbon—A. Preserve Land	0.44	$33.00	Sequestration
AFW-2b	Land Use Management Approaches for Protection and Enrichment of Soil Carbon—B. Reinvest in Minnesota–Clean Energy (RIM-CE)	0.19	$34.00	Sequestration
AFW-3a	In-State Liquid Biofuels Production—A. Ethanol Carbon Content	2.2	–$9.00	Transportation
AFW-3b	In-State Liquid Biofuels Production—B. Fossil Diesel Displacement	0.19	$55.00	Transportation
AFW-3c	In-State Liquid Biofuels Production—C. Gasoline Displacement	9	$5.00	Transportation
AFW-4	Expanded Use of Biomass Feedstocks for Electricity, Heat, or Steam Production	3.8	$3.00	Other
AFW-5a	Forestry Management Programs to Enhance GHG Benefits —A. Forestation	2.2	$13.00	Sequestration
AFW-5b	Forestry Management Programs to Enhance GHG Benefits—B. Urban Forestry	2.7	–$12.00	Sequestration
AFW-5d	Forestry Management Programs to Enhance GHG Benefits—D. Restocking	8.4	$33.00	Sequestration
AFW-6	Forest Protection—Reduced Clearing and Conversion to Non-Forest Cover	2.7	$3.00	Sequestration
AFW-7a	Front-End Waste Management Technologies— A. Source Reduction	3.6	$3.00	Other
AFW-7b	Front-End Waste Management Technologies— B. Recycling	3.4	–$11.00	Other

Recom-mendation No.	Climate Mitigation Recommendation	Estimated 2025 Annual GHG Reduction Potential ($MMtCO_2e$)	Estimated Cost or Cost Savings per ton GHG Removed	Sector
AFW-7c	Front-End Waste Management Technologies—C. Composting	0.41	$3.00	Other
AFW-8a	End of Life Waste Management Practices—A. Landfilled Waste Methane	0.73	$1.00	Other
AFW-8b	End of Life Waste Management Practices—B. Residuals Management	0.63	$80.00	Other
AFW-8c	End of Life Waste Management Practices—C. WTE Preprocessing	0.84	$32.00	Other
ES-1	Generation Performance Standard	0	$0.00	Power
ES-3	Efficiency Improvements, Repowering, and Other Upgrades to Existing Plants—Biomass Co-firing	0.4	$12.00	Power
ES-4	Transmission System Upgrading, Including Reducing Transmission Line and Distribution System Loss—Natural Gas Transmission and Distribution Upgrades	0.4	–$26.10	Power
ES-5	Renewable and/or Environmental Portfolio Standard	15.7	$56.40	Power
ES-6	Nuclear Power Support and Incentives—Installation of a Nuclear Power Station in 2020	NQ*	NQ*	Power
ES-8	Advanced Fossil Fuel Technology Incentives, Support, or Requirements	NQ*	NQ*	Power
ES-12	Distributed Renewable Energy	0.023	$78.10	Power
RCI-1	Maximize Savings From the Utility Conservation Improvement Program (CIP)	14.7	–$63.20	Power
RCI-2	Improved Uniform Statewide Building Codes	0.005	–$576.00	Other
RCI-3	Green Building Guidelines and Standards Based on *Architecture 2030*	0.94	–$27.00	Other
RCI-4	Incentives and Resources To Promote Combined Heat and Power (CHP)	4.95	$3.80	Other
RCI-5	Program To Reduce Emissions of Non-Fuel, High-Global-Warming-Potential GHGs	0.05	–$5.00	Other
RCI-6	Non-Utility Strategies and Incentives To Encourage Energy Efficiency and Reduce GHG Emissions	1.3	–$37.00	Other
RCI-7	Conservation Improvement-Type Program for Propane and Fuel Oil Efficiency	0.05	–$28.00	Other
RCI-10	Support Strong Federal Appliance Standards and Require High State Standards in the Absence of Federal Standards	1.4	–$124.00	Other
TLU-2	Expand Transit, Bicycle, and Pedestrian Infrastructure	0.3	$0.00	Transportation
TLU-5	Climate-Friendly Transportation Pricing / Pay-as-You-Drive	2.1	–$1.00	Transportation
TLU-6	Adopt California Clean Car Standards	1.16	–$39.00	Transportation
TLU-13	Reduce Maximum Speed Limits	0.4	$15.50	Transportation

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; AFW = Agriculture, Forestry, and Waste Management; ES = Energy Supply; RCI = Residential, Commercial, and Industrial; TLU = Transportation and Land Use; NQ* = Not quantified as these options were recommended for further study.

Table A-21 presents historical and projected GHG emissions from various sources in Minnesota. In Table A-22, we aggregate the GHG emission sources into three major sectors corresponding to the sector classification we used for mitigation options in Table A-20: (1) Power Sector, (2) Transportation Sector, and (3) Other. Emission from Sequestration is zero.

Table A-21. Minnesota gross GHG emissions by sector, 1990–2025: historical and projected

MMtCO$_2$e Source		1990	1995	2000	2005	2010	2015	2020	2025
1	Electricity (consumption-based)	35.03	40.88	43.40	54.14	57.06	63.82	71.27	79.45
2	Fossil fuel industry	1.37	1.95	2.12	2.25	2.60	3.02	3.50	4.07
3	RCI fuel use	25.61	31.08	31.32	32.00	34.99	37.17	38.64	40.48
4	Transport on-road gasoline	17.32	19.43	21.72	22.74	22.31	22.48	22.69	22.75
5	Transport on-road diesel	4.46	4.99	5.85	6.67	7.11	7.76	8.49	9.18
6	Jet fuel/other transport	6.91	7.25	7.85	7.81	7.15	7.39	7.62	7.86
7	Agriculture	15.53	17.53	19.50	19.68	20.51	21.36	22.24	23.13
8	ODS substitutes	0.00	0.08	0.41	0.65	0.93	1.23	1.60	2.06
9	Other industrial processes	0.61	0.79	0.96	0.91	0.87	0.85	0.87	0.89
10	Waste management	5.55	5.03	4.97	4.96	4.85	4.75	4.66	4.58
11	Forestry	3.30	3.30	3.30	3.30	3.30	3.30	3.30	3.30
	Total	**115.69**	**132.31**	**141.40**	**152.43**	**159.50**	**172.92**	**180.00**	**197.76**

MMtCO$_2$e = million metric tons of carbon dioxide equivalent; RCI = Residential, Commercial, and Industrial; ODS = ozone-depleting substance.

Table A-22. Minnesota gross GHG emissions from three major sectors, 1990–2025: historical and projected

	MMtCO$_2$e Source as in Table A-21	1990	1995	2000	2005	2010	2015	2020	2025
1	Power sector	35.03	40.88	43.40	54.14	57.06	63.82	71.27	79.45
4–6	Transportation sector	28.70	31.68	35.42	37.22	36.57	37.62	38.80	39.79
2, 3, 7–11	Other (e.g., Industrial, Commercial, Agriculture, Forestry, and Small Power Generation)	51.96	59.76	62.58	63.75	68.06	71.69	74.80	78.51
	Total	**115.69**	**132.31**	**141.40**	**152.43**	**159.50**	**172.92**	**180.00**	**197.76**

MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

The 2025 emission cap in Minnesota is 30% below the 2005 level. We assume this emission cap applies to each of the three major sectors, i.e., each sector has an emission cap of 70% of its emission level in 2005. Sequestration does not have a cap.

Table A-23. Cap in 2025: 30% below 2005 level

$MMtCO_2e$	2025 BAU Emission	Cap	Reduction Goal
Power sector	79.45	37.90	41.56
Transportation sector	39.79	26.05	13.73
Other	78.51	44.62	33.89

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent; BAU = business as usual.

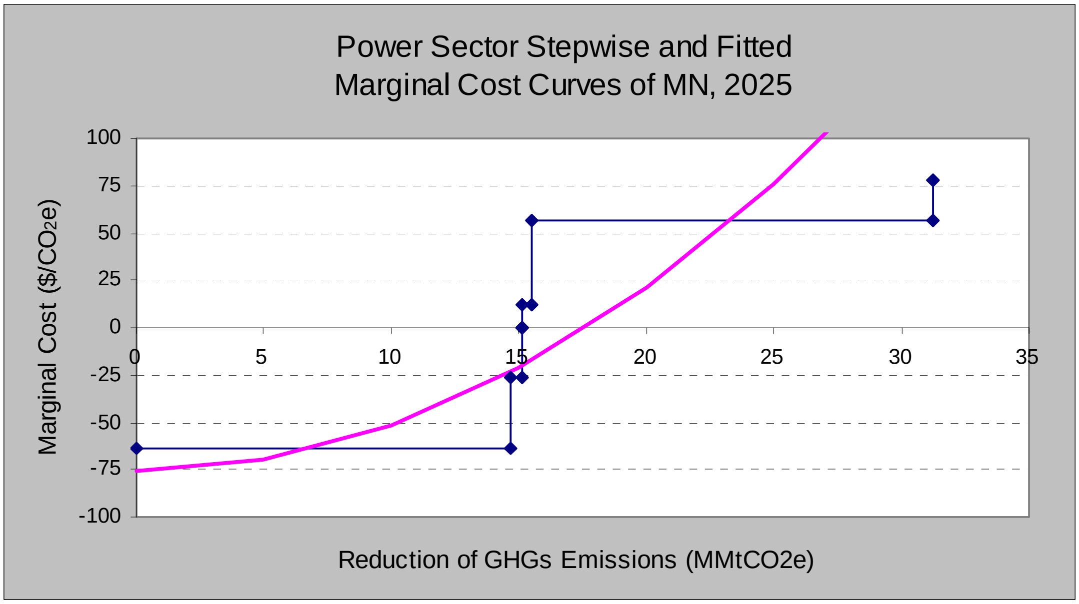
Next, we develop marginal cost curves for each of the four sectors. In the following figures of sector by sector cost curves, the horizontal axis represents the amount of GHG emission reduction. In previous interstate simulations, we designated the horizontal axis to represent percentage reduction of emissions. We did not use percentage reduction here but rather the actual amount of emission reduction along the horizontal axis because the emission from the Sequestration Sector is zero, and thus the percentage reduction cannot be defined for this sector.

Table A-24. Power sector

	Climate Mitigation Recommendation	Estimated 2025 Annual GHG Reduction Potential ($MMtCO_2e$)	Estimated Cost or Cost Savings per ton GHG Removed	Cumulative GHG Reduction Potential ($MMtCO_2e$)
RCI-1	Maximize Savings From the Utility Conservation Improvement Program (CIP)	14.7	–$63.20	14.7
ES-4	Transmission System Upgrading, Including Reducing Transmission Line and Distribution System Loss–Natural Gas Transmission and Distribution Upgrades	0.4	–$26.10	15.1
ES-1	Generation Performance Standard	0	$0.00	15.1
ES-6	Nuclear Power Support and Incentives–Installation of a Nuclear Power Station in 2020	0	NQ*	15.1
ES-8	Advanced Fossil Fuel Technology Incentives, Support or Requirements	0	NQ*	15.1
ES-3	Efficiency Improvements, Repowering and Other Upgrades to Existing Plants–Biomass Co-firing	0.4	$12.00	15.5
ES-5	Renewable and/or Environmental Portfolio Standard	15.7	$56.40	31.2
ES-12	Distributed Renewable Energy	0.023	$78.10	31.223

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; RCI = Residential, Commercial, and Industrial; ES = Energy Supply; NQ* = Not quantified as these options were recommended for further study.

Figure A-5. Power sector stepwise and fitted marginal cost curves of Minnesota, 2025



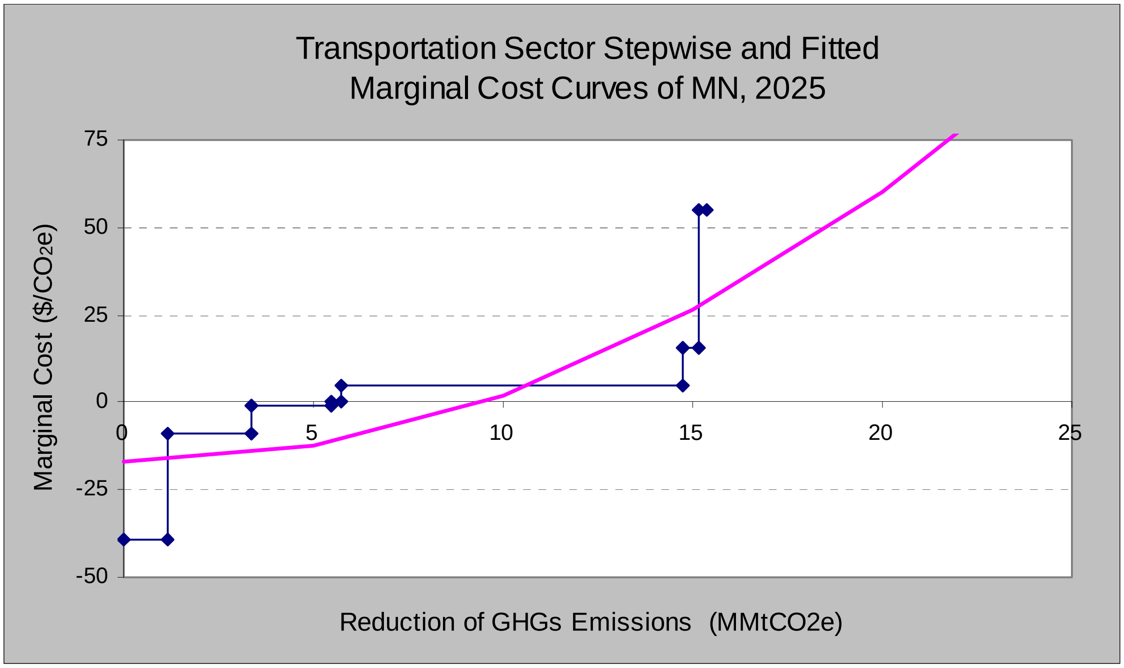
$/CO$_2$e = dollars per carbon dioxide equivalent; GHG = greenhouse gas; MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

Table A-25. Transportation sector

	Climate Mitigation Recommendation	Estimated 2025 Annual GHG Reduction Potential ($MMtCO_2e$)	Estimated Cost or Cost Savings per ton GHG Removed	Cumulative GHG Reduction Potential ($MMtCO_2e$)
TLU-6	Adopt California Clean Car Standards	1.16	–$39.00	1.16
AFW-3a	In-State Liquid Biofuels Production–A. Ethanol Carbon Content	2.2	–$9.00	3.36
TLU-5	Climate-Friendly Transportation Pricing / Pay-as-You-Drive	2.1	–$1.00	5.46
TLU-2	Expand Transit, Bicycle, and Pedestrian Infrastructure	0.3	$0.00	5.76
AFW-3c	In-State Liquid Biofuels Production–C. Gasoline Displacement	9	$5.00	14.76
TLU-13	Reduce Maximum Speed Limits	0.4	$15.50	15.16

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; TLU = Transportation and Land Use; AFW = Agriculture, Forestry, and Waste Management.

Figure A-6. Transportation sector stepwise and fitted marginal cost curves of Minnesota, 2025



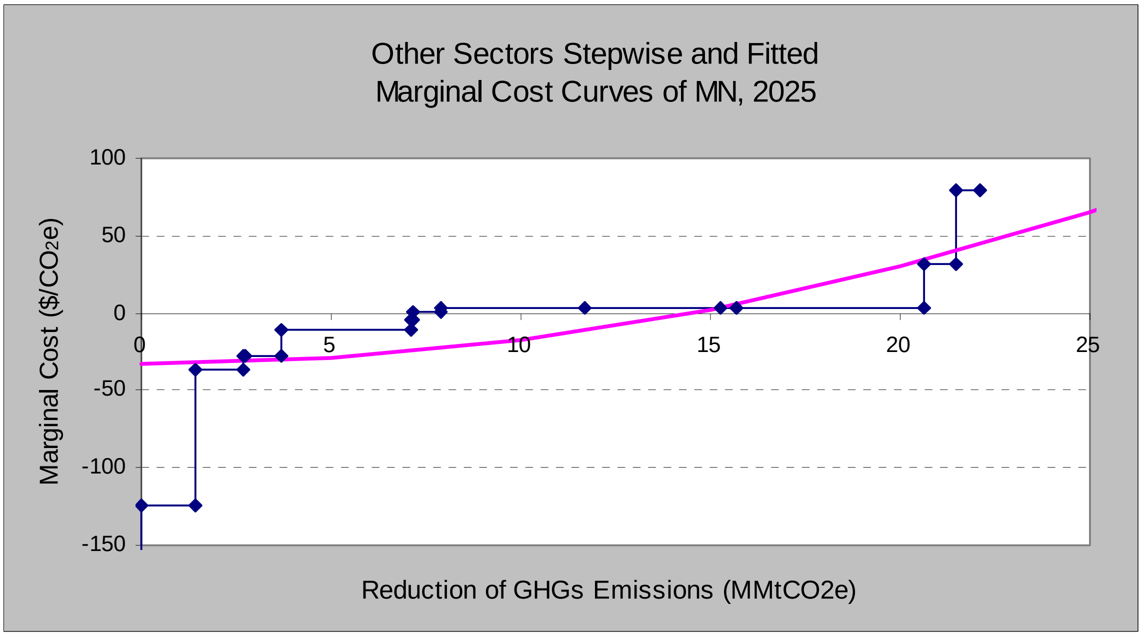
$/$CO_2e$ = dollars per carbon dioxide equivalent; GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

Table A-26. Other sectors

	Climate Mitigation Recommendation	Estimated 2025 Annual GHG Reduction Potential ($MMtCO_2e$)	Estimated Cost or Cost Savings per ton GHG Removed	Cumulative GHG Reduction Potential ($MMtCO_2e$)
RCI-2	Improved Uniform Statewide Building Codes	0.005	–$576.00	0.005
RCI-10	Support Strong Federal Appliance Standards and Require High State Standards in the Absence of Federal Standards	1.4	–$124.00	1.405
RCI-6	Non-Utility Strategies and Incentives To Encourage Energy Efficiency and Reduce GHG Emissions	1.3	–$37.00	2.705
RCI-7	Conservation Improvement-Type Program for Propane and Fuel Oil Efficiency	0.05	–$28.00	2.755
RCI-3	Green Building Guidelines and Standards Based on Architecture 2030	0.94	–$27.00	3.695
AFW-7b	Front-End Waste Management Technologies— B. Recycling	3.4	–$11.00	7.095
RCI-5	Program To Reduce Emissions of Non-Fuel, High-Global-Warming-Potential GHGs	0.05	–$5.00	7.145
AFW-8a	End of Life Waste Management Practices— A. Landfilled Waste Methane	0.73	$1.00	7.875
AFW-4	Expanded Use of Biomass Feedstocks for Electricity, Heat, or Steam Production	3.8	$3.00	11.675
AFW-7a	Front-End Waste Management Technologies— A. Source Reduction	3.6	$3.00	15.275
AFW-7c	Front-End Waste Management Technologies— C. Composting	0.41	$3.00	15.685
RCI-4	Incentives and Resources To Promote Combined Heat and Power (CHP)	4.95	$3.80	20.635
AFW-8c	End of Life Waste Management Practices—C. WTE Preprocessing	0.84	$32.00	21.475
AFW-8b	End of Life Waste Management Practices— B. Residuals Management	0.63	$80.00	22.105

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; RCI = Residential, Commercial, and Industrial; AFW = Agriculture, Forestry, and Waste Management; WTE = waste to energy.

Figure A-7. Other sectors stepwise and fitted marginal cost curves of Minnesota, 2025



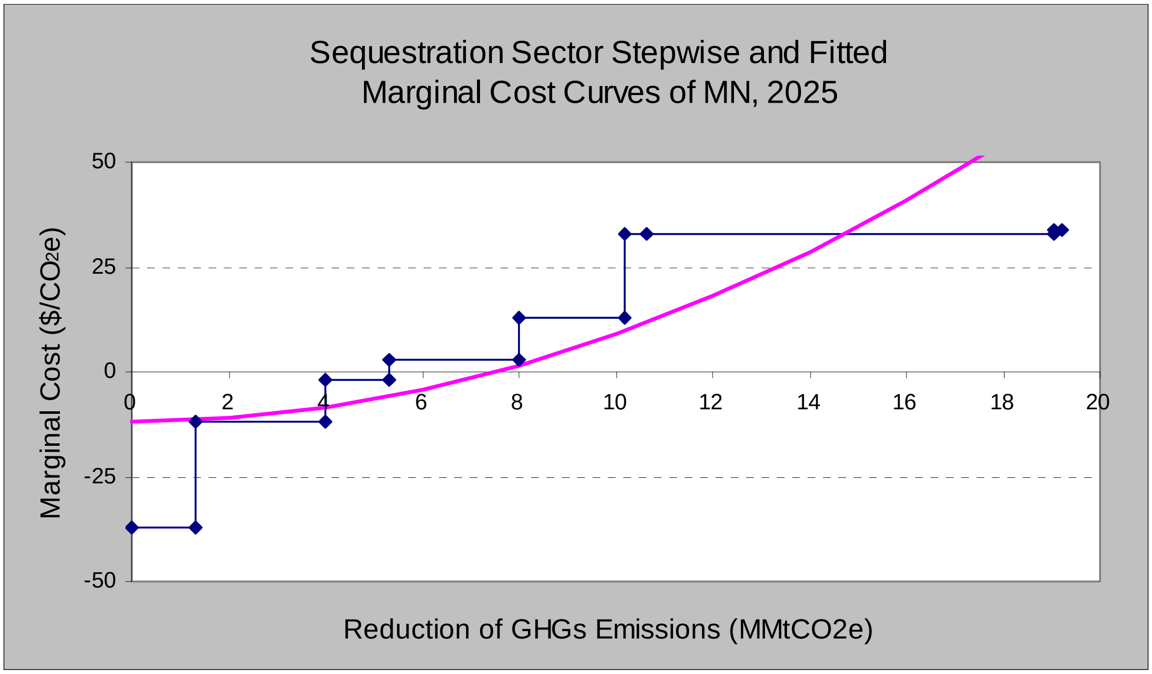
$/CO$_2$e = dollars per carbon dioxide equivalent; GHG = greenhouse gas; MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

Table A-27. Sequestration

	Climate Mitigation Recommendation	Estimated 2025 Annual GHG Reduction Potential (MMtCO$_2$e)	Estimated Cost or Cost Savings per ton GHG Removed	Cumulative GHG Reduction Potential (MMtCO$_2$e)
AFW-1b	Agricultural Crop Management—B. Nutrient Management	1.3	–$37.00	1.3
AFW-5b	Forestry Management Programs to Enhance GHG Benefits—B. Urban forestry	2.7	–$12.00	4
AFW-1a	Agricultural Crop Management—A. Soil Carbon Management	1.3	–$2.00	5.3
AFW-6	Forest Protection—Reduced Clearing and Conversion to Non-Forest Cover	2.7	$3.00	8
AFW-5a	Forestry Management Programs to Enhance GHG Benefits—A. Forestation	2.2	$13.00	10.2
AFW-2a	Land Use Management Approaches for Protection and Enrichment of Soil Carbon —A. Preserve Land	0.44	$33.00	10.64
AFW-5d	Forestry Management Programs to Enhance GHG Benefits—D. Restocking	8.4	$33.00	19.04
AFW-2b	Land Use Management Approaches for Protection and Enrichment of Soil Carbon—B. Reinvest in Minnesota–Clean Energy (RIM-CE)	0.19	$34.00	19.23

GHG = greenhouse gas; MMtCO$_2$e = million metric tons of carbon dioxide equivalent; AFW = Agriculture, Forestry, and Waste Management.

Figure A-8. Sequestration sector stepwise and fitted marginal cost curves of Minnesota, 2025



$/CO$_2$e = dollars per carbon dioxide equivalent; GHG = greenhouse gas; MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

Table A-28. Emission trading simulation among four sectors in Minnesota (assume no CIP/RES in baseline) (million $ or otherwise specified)

	Before Trading	After Trading*				Permits Traded	Emission Reduction After Trading		Emission Reduction Cap
State	**Mitigation Cost**	**Mitigation Cost**	**Trading Cost**	**Net Cost**	**Cost Saving**	**($MMtCO_2e$)**	**($MMtCO_2e$)**	**(Percent From BAU)**	**(Percent From BAU)**
Power Sector	$2,653	–$692	$1,141	$449	$2,203	17.42	24.14	30.38	52.31
Transportation Sector	–$68	$216	–$457	–$241	$173	–6.98	20.71	52.06	34.51
Other	$928	–$9	$584	$575	$352	8.92	24.97	31.80	43.16
Sequestration	$0	$272	–$1,268	–$996	$996	–19.36	19.36	N/A	N/A
Total	**$,512**	**–$213**	**$0**	**–$213**	**$725**	**26.35**[†]	**89.18**	**45.10**	**45.10**

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent; BAU = business as usual; N/A = not applicable.

* Permit Price = $65.48/$tCO_2e$.

† Represents number of permits bought or sold.

The simulation results show that Power Sector and Other Sector would buy permits from Transportation Sector and Sequestration Sector.

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IV. COMMENT ON ENERGY SUPPLY

ES 1: Generation Performance Standards

"It is unclear why the reductions from this proposal are not included in the summary of potential reduction options. Even if they may be subsumed under the cap and trade policy, they should be included for consistency with other portions of the report. It is also unrealistic to assume that electricity with a mix of ('75% renewable and 25% wind') could be easily purchased from out-of-state to replace potential Minnesota coal-powered electricity. The states surrounding Minnesota currently have more coal-intensive electricity production than Minnesota does."

P Reich (Regents Professor, Dept of Forest Resources, U of Minnesota)
E Nater (Professor & Department Head, Dept of Soil, Water and Climate, U of Minnesota)
S Hobbie (Associate Professor, Dept of Ecology, Evolution, and Behavior, U of Minnesota)
J Espeleta (Research Associate, Dept of Soil, Water and Climate, U of Minnesota)
C Fissore (Research Associate, Dept of Soil, Water and Climate, U of Minnesota)
L Olabisi (Research Associate, Ecosystem Science and Sustainability Initiative, U of Minnesota)
A Ek (Professor & Department Head, Dept of Forest Resources, U of Minnesota)

"I believe exempting the Masaba coal plant from emission standard is not only wrong but unethical. We need to be reducing these toxic gases, not building new plants that increase carbons. I will watch to see who supports the exemption and make sure they are voted out of office or are not appointed again."

Joel J. Olander GCA, Owatonna

"We strongly feel the Mesaba Energy Project should not be exempt from Minnesota CO2 standards. Mesaba Unit 1 would emit 5.3 million tons per year of CO2. Minnesota is trying to reduce GHG emissions, not increase them. The Mesaba Energy Project is a federally funded demonstration of carbon capture and sequestration which is not possible in Minnesota. If this plant is to be of any benefit to taxpayers or rate payers it must be built closer to the coal, closer to where the power is needed, and closer to a sequesration site. Many other states have cancelled potential coal gasification projects. Minnesota should do the same. Thank you."

Jim and Steph Shields, Pengilly, MN

"I could not disagree more strongly with the position of the MCCAG in exempting both the Mesaba Project and Big Stone 2 from controlling carbon dioxide emissions. Global warming is a serious problem that requires immediate action. Elimination of carbon dioxide emissions should be a basic part of any new coal-fired power plant, not an augmentation that may or may not be added at some time in the future. Given the threat of ongoing climate change, "grandfathering" in huge new sources of atmospheric carbon just because they are already in the process of bureaucratic review would be unconscionable. With regard to this report, I support the first goal in Appendix G, specifically that the reasonable approach for all concerned is to keep utilities from making long-term investments in high-carbon-generation technology."

William Steele, Bovey, MN

"Facts against Mesaba's exemption from CO2 Emission Standards: Mesaba1@2 will emit 10.6 million tons/yr CO2. Existing tech capture only 30% CO. Equipment .cost est.$1 billion. Not economical. CC equipment not installed until needed by law. Mesaba will add 8 million tons/yr to MN's GHG emissions even with CCS. Conflicts with goal of reduction in MN GHG emissions. Protection denied to citizens when Cos. are given exemption.

Darrell and Delores White, Bovey, MN

"Please do not build in damaging loophole exemptions into the CO2 policy & rules. This would be unfair to other industries and our future. It is my understanding that exempting the proposed new Mesaba and Big Stone 2 dirty coal plants will result in an additional 4.7 MMtCO2 when they come on line in 2013. Application of the GPS to these coal units would result in GHG reductions of 4.7 MMtCO2 in 2015 and 4.8 MMtCO2 in 2025 (a cumulative reduction of 61.8 MMtCO2.)"

Bill Barton, St Paul, MN

"I have been following the Mesaba Energy Project pretty much since it inception. I am aghast that any project that will pollute the air, water, and land is even given any consideration. Those resources are finite and I have a real problem with someone who does not even live in this area proposing to take those valuable resources away from those of us that do live here. I grew up north of the proposed Mesaba Energy site and have always enjoyed and respected the clean water on the lake where I grew up. I love walking in the woods and breathing the clean air. If the Mesaba project is allowed to be built and they are exempt from any pollution reducing modifications, that amounts to poisoning the earth for present and future generations. When those finite resources/treasures are polluted beyond use, mankind will truly suffer. What will we or our future generations do when there is no more clean water to drink, clean air to breathe, or clean land to walk? As far as I am concerned, any pollution is too much and any new/additional pollution is unacceptable. Please do not exempt the Mesaba Project from following the guidelines we all should have to adhere to in order to keep our one and only earth a truly great place to live. We need to work harder to keep what we have and not throw it away for something we don't need or want."

Kathy Krook, Grand Rapids, MN

"Please do not exempt the mesaba project from CO2 emission standards. Please consider our desire for clean air and an environment free of anything that adds CO2 to the air. Tthank you."

Mary Shidele, Grand Rapids, MN

"Do not exempt Mesaba from the CO2 standards. We do not need the power they would generate, and we surely do not need the extra CO2."

Nicholas Eltgroth, Cohasset, MN

"It is imperative that we work quickly to change our policies regarding CO2 emissions and reduce greenhouse gases. Why on earth is it even being considered to exempt Mesaba from CO2 emissions? What message does this send to individuals who are being encouraged to change their lightbulbs, buy energy star appliances, reduce their fuel consumption, when industry is hurling us towards environmental disaster? I believe government has a responsibility to protect our environment and not industry development. An exemption would certainly be viewed as corruption."

Barbara Bunte, Grand Rapids, MN

"Please do not exempt Mesaba from CO2 emission standards! This conflicts with the goal of reducing Minnesota's GHG emissions. This would be bad for our environment and bad for our health. Financial issues should not be placed above the long term health and well being of our citizens and our planet. We need to error on the side of our future. Thank you."

Lisa Bolton, Grand Rapids, MN

"Mesaba Units 1&2 will emit 10.6 million tons of CO2 per year. The Mesaba project does not have a viable plan to capture/sequest carbon. The US Department of Energy recently cancelled its support of carbon sequestration at proposed FutureGen coal plant in Illinois. The DOE cited excessive costs of the carbon capture process. The Mesaba Enmergy Project at this point is only a proposal. The power is not needed in Minnesota and Excelsior Energy has no Power Purchase Agreement, ,no customer or plan to capture CO2.Even if CO2 Carbon Capture were implemented, Mesaba would still add 8 million tons per year to

Minnesota Green House gas emissions. Exempting the proposed high risk Mesaba Energy project from CO2 emission standards is environmentally irresponsible and not in the best interest of the citizens of Minnesota."

Linda Castagneri, Proctor, MN

"My objection is to the exclusion from the proposed limits of all planned capacity additions that are already at some stage in the regulatory process in Minnesota and that will not meet the threshold."

Marian Champlin, Bovey, MN

"I object to this project that would put millions of tons of co2 into our atmosphere. Do not give an exception. The c02 from this plant needs to be sequestered."

Nicholas Eltgroth, Cohasset, MN

"The last thing we need is tons and tons more of CO2 pollution. We already have more than is healthy for us and the planet from the surrounding mines. Please do not grant any environmental or pollution exemptions to Excelsior's Mesaba Energy Project. We have sufficient energy without this Project, and the country is on the verge of doing energy efficient and innovative programs in the near future. Do not condemn those of us who live here to unnecessary pollution for an unnecessary project."

Charles Grant, Nashwauk, MN

"It would be very disappointing if the Minnesota State Legislature were to exempt the Mesaba Energy Project from proposed CO2 and pollution regulations. It is hard to understand how the legislature could take this ill-conceived action, particularly at a time when it is competing with the Governor to impress the electorate with its environmentally progressive stance. If this project were to be built, it would rival Alaska's famous "bridge to nowhere" as a ridiculous expenditure of tax dollars."

Stephen Clark, Bovey, MN

"We strongly disagree with MCCAG s recommendation to exempt the proposed Mesaba Energy project from the CO2 emission standards and find this recommendation to be terribly short-sighted in addressing challenges to the earth from global warming. Exempting the proposed Mesaba project from the CO2 standards would significantly undercut any benefits gained from state initiatives to reduce CO2 emissions. Company documents state that the Mesaba Units I and II will emit 10.6 million tons/year of CO2, and Excelsior Energy has no plans to install carbon capture equipment unless it is mandated by law. Besides, we understand that existing technology could capture only 30% of the CO2. The proposed project has been touted as being clean because it could, in some vague, future plan, include carbon sequestration; but not only is this technology unproven, the Minnesota Geological Survey found that the geology of northeastern Minnesota will not work for deep geologic sequestration of CO2, so the CO2 would have to be sent via pipeline to North Dakota or Canada. The necessary equipment and pipeline for this has been estimated to cost $1 billion dollars and Excelsior Energy s DEIS stated that new public money would be necessary to implement any carbon capture or sequestration. Even if the money was found (and diverted from other important societal needs), and the pipelines were built, the DOE has concluded that carbon capture and sequestration (CCS) could increase the cost of electricity by as much as 40%. So, not only would the public be paying for the costs of building a facility that is completely against the Governor s well-publicized goals for cleaner energy standards, families would have to pay more for this electricity. Finally, even if Mesaba incorporated carbon capture and sequestration into its project, Mesaba would still be adding 8 million tons/year to Minnesota's GHG emissions, and thus would cancel out any gains from other companies' CO2 reductions. What sense does this make? Your Energy Supply Recommendation ES-1: to prevent utilities from making long-term investments in high-carbon generation technology is what we need. Exempting the proposed Mesaba project from this goal smacks of pure political lobbying and completely undercuts the wise intention of your goal. There are so many arguments against Mesaba s planned facility. It is time to adopt policies that are future-oriented such as non-carbon-producing strategies to produce power, as well as encouraging energy conservation. It s now time to end all consideration of the Mesaba project, NOT give them exemptions that allow them to prolong their efforts toward building their CO2-belching scheme. Sincerely,"

Loree and Matthew Miltich, Grand Rapids, MN

"Mesaba should be held to the same standard as any other generating facility; there is no valid reason not to."

Donald Janes, Dellwood, MN

"I fully support the Mesaba Project and their clean coal technology. If all the coal plants in the world used this technology the environment would be much cleaner. Although not perfect, it's the next step in clean energy."

Mike Andrews, Grand Rapids, MN

"The planned Mesaba and Big Stone II plants should not be exempt from the next generation power plant guidelines."

Hillary Oppmann, Minneapolis, MN

"The GHG reductions that could be achieved by refusing to permit the Mesaba and Big Stone II coal plants (and the cost effectiveness thereof) should be included in this analysis. These are the only new coal plants that will likely be built between now and 2025, so they are highly significant. Stopping their construction may be crucial to make progress in GHG reductions, and quantifying these reductions and their cost effectiveness in this report will give us a clearer picture."

Matthew Tyler, Finland, MN

"Exempting Mesaba Energy from CO2 Emission Standards conflicts with the goal of reducing Minnesota Green House Gas Emissions. Mesaba 1 & 2 will emit 10.6 million tons per year of CO2. Excelsior has no workable plan for the capture and sequestration of CO2. The US Department of Energy cancelled its support of FutureGen, an experimental coal burning plant Illinois, attempting to sequester CO2 emissions. The DOE cancelled its support citing excessive costs; it is now unclear if it will ever be built. Experts found to reduce carbon emissions from coal by just 10% , a volume of CO2 equivalent to all the oil pumped world wide would need to be forced underground at a possible cost of a trillion dollars. The Minnesota Geological Survey concluded that there is a low probability of success in confirming suitable conditions for CO2 sequestration in MN. The Mesaba Energy project has no purchase agreement in place, and therefore no customer to purchase its electricity. The exemption should not be granted for a power generation facility that is not needed and cannot capture or sequester CO2."

Ronald Gustafson, Bovey, MN

"My company manufactures equipment to reduce air CO2 emissions from industrial power generation plants and we are developing new alternative energy technologies as a result of the climate change concerns. I was formerly the Manager of Alternative Energy Projects for the state of Minnesota and helped develop one of the first climate simulations concerning greenhouse gases (in 1968). I am gratified that the environmental damage from high CO2 emissions is now more accepted by our politicians, the public, and your group and the need for IMMEDIATE CO2 reductions appreciated. Therefore, I am extremely concerned that the climate change advisory group is even considering exempting the proposed Bigstone II and Mesaba coal-fired electric power plants from an otherwise wise choice in limiting new coal-fired power generation in Minnesota (unless or until a cost-effective carbon sequestration method for fossil fuel is developed). I am also concerned that the Group appears to have decided not even to include those plant's CO2 emissions in the reduction calculations. Neither decision makes any rational sense if the goal is to reduce CO2 emissions. Both projects (and the many additional Mesaba units proposed) increase state CO2 emissions by approximately 17%. Since the vote on these exemptions was apparently "very close", and their emissions data "not included", I assume many of your members understand how badly such exemptions will reflect on your work. Since these exemptions are so inconsistent with the purposes of your group, I can only assume your concern is that halting projects already in the approval process would cause some financial hardship to the applicants. But construction on these unneeded facilities has not begun. Mesaba has and will remain a complete waste of taxpayer dollars. No private company or individual would be "out" any money if it cancelled (in fact, the project is so badly conceived it will save taxpayers hundreds of millions of dollars to cancel it now anyway). Bigstone II if operated under any reasonable CO2 limitations would quickly become one of the most expensive electric power generating plants supplying power to Minnesota. It could not compete with amortized (older) coal plants given its high construction costs PLUS the additional CO2 costs anticipated and has nothing new to offer compared with the existing plants. Bigstone II would financially punish ratepayers (individual and business) and reduce the opportunity for lower CO2 options to compete when additional "need" actually develops. It is far better to terminate this project now; even if it means the minor private costs to date are compensated in some way. The effect of allowing these projects to go forward sets back your group's CO2 reduction goals by tens of years. It does not cost much to stop these counterproductive projects now. I urge your group to include their CO2 emission data and vote for NO EXEMPTION. Thank you."

Ron Rich, Atmosphere Recovery, Plymouth, MN

"Mesaba energy project must not be exempt from emission polluting regulation. We need to move away from fossil fuels and concentrate our efforts towards renewable energy like wind and solar."

Chad Johnston, Bovey, MN

"CO2 emissions obviously have a worldwide effect. I hope that you'll allow people who take the time to comment to participate, since global warming is a global problem that will take a global solution. Exempting Mesaba is exactly the WRONG thing to do. Global warming is a huge "market failure" -- where the tragedy of the commons may be ecosystem collapse, all because we were too greedy to realize that pollution has a VERY REAL price. Please, be a leader. NOW. Not later. Exempting Mesaba is the WRONG thing to do. The Midwest has so much wind it's amazing! And wonderful. Please, let's invest in the future -- not the past."

Nancy LaPlaca, Denver, CO

"To exempt the Mesaba Project from carbon emission controls is FOOLISH! First, the electricity from the proposed project is not needed. Secondly the environmental impact from such carbon emission would greatly add to our present problem of global warming and climate change. The cost of controlling carbon emission is prohibitive...the ability to control emission is limited...sequestering CO2 is limited and would be costly to transport to where it could be used. This project should not be approved."

Lyle G. Lauber, Squaw Lake, MN

"Exempting the Mesaba Energy Project from the generation performance standard, while planning to reduce Minnesota's GHG emissions, defies logic and common sense. The policy's stated goal is to prevent utilities from making long-term investments in high-carbon-generating technology; presumably this also applies to a private, for-profit, independent power producer seeking to force its output on Minnesota utilities. This Project is still in the preliminary design phase and the fact that it is in the regulatory process is not a reason to permit it to annually spew ten million tons of CO2 into the atmosphere for possibly 50 years. Excelsior admits that: Mesaba Units I and II will emit 10.6 million tons/year of CO2; carbon capture equipment will not be installed until mandated by law; existing technology could capture only 30% of the CO2; the CO2 most likely would have to be transported by pipeline hundreds of miles to the west; and about 10% of CO2 injected into the ground will not remain sequestered. Even if carbon capture and sequestration (CCS) were implemented, Mesaba would still be adding 8 million tons/year to Minnesota s GHG emissions. The Minnesota Geological Survey has recently concluded that there is a very low probability of success in confirming suitable conditions for deep geologic sequestration of CO2 in

Minnesota. The Department of Energy, at page 3 of Appendix A2 of Mesaba s draft EIS, regarding the feasibility of CCS, stated: it could increase the cost of electricity by as much as 40%; even if the CO2 could be sold for enhanced oil recovery, the revenues would be grossly insufficient to recover the costs of CCS; and without a PUC order incorporating CCS costs within the power purchase agreement (PPA), Mesaba would not be economically viable. Even without the estimated $1 billion cost for 30% CCS, the Minnesota PUC has determined that Mesaba s electricity is too expensive and that its operational and financial risks should not be imposed on Xcel s ratepayers. The PUC agreed with the ALJs in the PPA docket that: including CO2 in the emissions required a finding that the plant had little or no quantifiable advantage at this time over other coal burning plants and no advantage over baseload generators operating on renewables . The ill-advised Mesaba Project has survived this far only because of $40 million of public funding and exemptions from Minnesota s laws and rules. CAMP opposes any additional regulatory benefits for Excelsior Energy s Mesaba Project, and it is unreasonable for the MCCAG to recommend this one."

Charlotte Neigh, Co-Chair Citizens Against the Mesaba Project (CAMP), Grand Rapids, MN

"It is absolutely unacceptable to exempt a proposed power generation plant from CO2 emission standards; specifically the Mesaba/Excelsior Energy gasification plant on the Iron Range. I urge legislatures to confirm their commitment to reduce greenhouse gas, resist pressure from past practices, and stand strong supporting initiatives that promote a sustainable future, and rejecting proposals that would be detrimental. There is no justification to exempt Mesaba/Excelsior Energy, a proposed project that is not based on need."

Jeanne Newstrom, Bovey, MN

"Mesaba Units I and II will emit 10.6 million tons/year of CO2. Carbon capture equipment will not be installed until mandated by law. The Minnesota Geological Survey has recently concluded that there is a very low probability of success in confirming suitable conditions for deep geologic sequestration of CO2 in Minnesota and would most likely have to be transported by pipeline hundreds of miles to the west. Existing technology could capture only 30% of CO2 and necessary equipment and pipeline has been estimated at $1 billion. Even if CCS were implemented, Mesaba would still be adding 8 million tons/year to Minnesota's GHG emissions. Action is needed NOW to stop global warming and exempting any power plant from CO2 emission standards is irresponsible and will affect the future of the entire globe in years to come."

Lee Ann Norgord, CAMP, Bovey, MN

"I do not favor any exemption for either the Mesaba Coal Gasification plant or the Big Stone Power Plant. Neither will help reduce green house emit ions. Both will add to further Mercury pollution. I think both are a political Bamboozle!!!"

Donald St. Aubin, Grand Rapids, MN

"Stop this plant it is obvious the scams that are currently being generated are the only energy that it going to come out of it, and it all about the company making money, nothing to do with us here in N. MN and absolutely nothing to do with protecting our world from greedy power hungry elitist snobs."

Bryan Stenlund, Grand Rapids, MN

"It would be irresponsible to make any exclusion to legislation that is designed to prevent global warming. Also, Dick Stone, Excelsior Energy's VP for Development and Engineering, should not have been allowed to be a member of the Energy Supply Working Group that would give exemptions to Excelsior Energy and Big Stone 2. Global warming is a real threat to the survival of the world as we know it, and CO2 from the Mesaba Project and Big Stone 2 would exacerbate the problem."

Robert Norgord, CAMP, Bovey, MN

"Please stop the Mesaba Energy boondoggle. It does not sequester carbon. It's just a few crony capitalists exploiting the Iron Range political machine to bleed resources from our efficiently regulated utility system.

My wife and I are retired in northern Minnesota. We object to our tax dollars being used to promote a project that will damage our economy and our environment."

Bob Tammen, Soudan, MN

"I am writing to object to the MCCAG's recommendation to exempt Excelsior Energy form the carbon emission standards at its proposed Mesaba generation plant. It should be obvious to everyone that carbon sequestration will not occur if this project moves forward. The geology of the local terrain will not allow co2 sequestration and the cost o transporting it to an area with suitable geology is prohibitive. Minnesota has mandated that electricity production must come from renewable sources in the near future. Projects such as the proposed Mesaba project fly in the face of that mandate. I suggest that politics be removed from all consideration of this proposa.l"

Richard Twaddle, Bovey, MN

"As a citizen of Grand Rapids MN I strongly oppose the MCCAG decision to exempt Mesaba from CO2 emission standards. You unanimously support 'strong federal standards and requiring high state standards' yet exempt a proposed facility [Mesaba Units I&II] which will emit over 10 and 1/2 million tons per year of CO2! Furthermore, 24% of green house gases in MN are from transportation, and most pollution/GHG estimates re: Mesaba don't even factor in the transport of coal! Sequestration of CO2 in this region, if possible at all, is technologically complicated, and at best, would be inefficient and incomplete! How can a climate change advisory group exempt a proposed project of this magnitude? This is unthinkable. Moreover, Mr. Stone should recluse himself from making decisions re: Mesaba! If we are to address current and future climate change we MUST take action NOW, this according to credible science. There is no good reason for such an exemption. Quite the contrary, now more than ever we are called upon to scrutinize proposed energy producing projects...In looking at the Mesaba project, one is led to question the gross environmental costs, financial costs, and the opportunity cost of all this capital that could be better invested in true "alternative" energy! Please reconsider this short sighted and ill-conceived exemption! Thank you."

Jenny M Wettersten, Grand Rapids, MN

"Exemption of the Big Stone 2 and Mesabi coal fired power plants is a lost opportunity. Here are the first two plants slated to be built, and we choose not to take the opportunity to look for a better option than to continue to rely on fossil fuels to provide our energy. These plants should be included in any cap and trade framework."

Brian Nerbonne, Minneapolis, MN

"Debate Over Applying the GPS to Big Stone II and Mesaba Coal Plants

The ES-1 Generation Performance Standard (GPS) was one of the most controversial policies considered by the MCCAG. This standard would prevent Minnesota utilities from making new long-term investments in coal power unless the plants meet a CO2 emissions standard that in effect would require them to employ carbon capture and storage technology. The GPS described in the policy description set forth in Appendix G was modeled after California s GPS. The MCCAG voted to recommend adoption of a GPS standard that applies to coal plants yet to be proposed (though because the MCCAG did not anticipate any more coal plant proposals during the planning period, there are no actual pollution savings to be had by applying the GPS to them). Many MCCAG members, though not a majority, also supported applying the GPS to currently pending coal proposals (Big Stone II and Mesaba). Since neither of those proposals employ carbon capture and storage technology, applying the GPS standard to pending proposals would bar their construction.

Huge cost and pollution savings from barring construction of unneeded coal plants

An analysis conducted by CCS of the cost and emissions impact of applying the GPS (ES-1) to Big Stone II and Mesaba is presented for informational purposes at page G-2. It indicates that blocking these two new coal projects would yield dramatic cost and pollution benefits -- saving 61.8 million tons of emissions and $7.4 billion dollars between 2013 and 2025. (These may even be underestimates since CCS assumed rather low emissions and ignored the costs of future CO2 regulations, among other costs). The reason this analysis showed such large savings relates back to another important finding of the MCCAG process namely that these new coal plants are not needed given the state s existing renewables and efficiency policies. As the state implements the new energy efficiency legislation of 2007, the MCCAG analysis projects that our electricity demand growth rate will shrink from 2.04% (p. EX-5) to a more modest 0.82% (p. 4-2). When this lower demand growth is combined with the effects of the 2007 Renewable Energy Standard (which requires Xcel to get 30% of its power from renewables by 2020 and other utilities to get 25% from renewables by 2025) it results in a steady and sustained decline in state demand for power from coal plants. This declining demand will allow the state to start backing down the operation of existing coal plants and to claim credit for reduced CO2 emissions as a result (see Figure 4-1, which illustrates the sustained drop in emissions from coal caused by the projected drop in demand for coal power).

Since our demand for coal power is projected by the MCCAG analysis to shrink in the years ahead, new coal units are simply not needed to serve Minnesota electric load. Therefore, a policy that prevents their construction saves Minnesota a great deal of pollution and money. There is no need to replace the power the plants would have generated because that power will be replaced by efficiency and renewables as the new laws are implemented. The methodology for calculating these cost and pollution savings presented in Appendix G for ES-1 was disputed by some members of the MCCAG, which is why it is presented for informational purposes only. However, in its fundamentals it is surely sound: any policy that prevents the construction of coal plants that Minnesota does not need will save large amounts of both money and pollution.

No process considers impact of new coal plants on state emission reduction goals

Members who did not want the GPS to apply to Big Stone II and Mesaba also urged the MCCAG to defer to the judgment of the Public Utilities Commission (PUC) regarding approval of those plants. As the final report notes, the majority on the MCCAG did not favor applying the GPS to Big Stone II and Mesaba because they are currently undergoing regulatory review. (4-4). However, the regulatory review being conducted by the PUC is held under different laws and standards and does not in any way look at the impact these new plants would have on the state s overall emission reduction efforts. The PUC is not considering, for example, which emission sources will have to reduce their emissions if these coal plants are built, or how much those reductions will cost those sources or the state as a whole. The PUC is not asking whether building two large and costly coal plants at a time of declining demand for coal power is part of a least-cost path to achieving our emission reduction goals, nor is any other state regulatory body or process.

Unfounded Assumption That Old Coal Units Will Back Down As New Ones Are Built

Because the state's need for coal power is projected to decline, the two new coal plants presented an analytical challenge for the MCCAG. If the MCCAG assumed that the plants were built and operated as proposed and that all existing units continued to operate as they do today, it would result in the generation of far more electricity than the state is projected to need (indeed, this will be true to a certain extent even if the new coal plants are not built). Over the objections of several MCCAG members, the final report assumes a backing down of existing units if the Big Stone 2 and Mesaba units come on line in order to balance the supply of electricity with the demand in Minnesota (page EX-5). This is why none of the graphs in the report show the over 5 million tons of CO2 these new plants would suddenly begin emitting around 2013 when they are assumed to come on line. By assuming that existing coal units will suddenly reduce their output if the new plants are built, the report essentially makes these two new coal unit, the largest new CO2 sources built to serve Minnesotans in decade, disappear from the analysis.

Many members of the MCCAG objected to making this unfounded assumption. Backers of the two new coal plants have been promoting them to regulators, ratepayers, and the public as needed to meet increasing demand, not as a way to displace existing coal generation. (And if the point were to displace old coal units, it would likely be far cheaper to construct the new units where the old units are being taken offline to avoid having to build costly new power lines and other infrastructure.) The plants backers are under no commitment to take any of their old coal units offline when the new units come online, and the owners of the other coal plants serving Minnesota have no plans nor any incentives to reduce their output. Given that there is no requirement, plan or incentive to back down existing coal units, it is far more likely that the excess coal power would simply be sold to consumers outside of Minnesota through the regional power market, undermining regional investments in renewables and efficiency. Under the statutory definition of statewide greenhouse gas emissions (Minn. Stat. section 216H.01), the CO2 associated with these coal power exports would still be counted, and rightly so, since it would be every bit as damaging to the climate as CO2 associated with power consumed by Minnesotans. It was certainly not the intent of the legislature in passing the emission reduction targets to have Minnesota meet them by exporting its extra coal power to others. Indeed, the CO2 reductions associated with the state s energy efficiency efforts and RES are in no small part associated with displaced coal power; to the extent that displaced coal power is simply exported, those policies will have no beneficial effect on the climate. It is critical that Minnesota policy makers keep this all important back-down assumption in mind in the event that the Big Stone II and Mesaba units are actually built. If the state does not translate this assumption into reality by ensuring that older coal units actually reduce their generation, then Minnesota will fall millions of tons short of meeting its emission reduction targets. The 2015 target is particularly in jeopardy, given that backers of the two new coal plants have been hoping to bring them online in 2013."

Barbara Freese, Union of Concerned Scientists, Minnesota Center for Environmental Advocacy, Izaak Walton League of America - Midwest Office, Fresh Energy, Global Green Energy LLC, Institute for Agriculture and Trade Policy, Clean Water Action, St Paul, MN

"I see no reason for Mesaba Energy to have an exemption from the CO2 emission standards. These standards are in place to protect the public and the environment and should be enforced for everyone and every business."

William R Wheeler, Bovey, MN

"I own property in Bovey, MN at 23029 Co. Rd. 71, 55709. I have lived in northern Minnesota for most of my life: as a full time resident in my youth and as a summer resident as an adult. I currently live in Columbus, OH which is recognized as having high pollution and bad air quality. Poor air quality in Ohio goes into our lungs and into the soil. Poor air quality in Minnesota goes into the lakes. It is NOT tolerable to allow higher CO2 and GHG emissions for Mesaba development. Natural resources are Minnesota's economic resource and should not be endangered or destroyed by shortsightedness. GHGs worldwide need to be controlled. Please do not exempt Mesabi and Big Stone 2 from the standards necessary to control greenhouse gases. Don't allow a polluter to build in our back yard! Or anywhere on this earth! I'm planning to move back to Minnesota for many reasons. Please do what is necessary to keep one of the reasons valid: "It is a cleaner state."

Heidi Wick, Columbus, OH

"I am against the exemption of MESABA from the CO2 emission standards as this conflicts with the goal of reducing MN GHG Emissions. As a resident of this area I feel that this is a significant health issue for myself and others."

Nancy Wheeler, Bovey, MN

"The exemption of the Mesaba Energy Project (MEP) from any climate control legislation will make that legislation meaningless. / [Minn. Stat. 216B.1694, Subd. 1, Definition. For the purpose of this section, the term innovative energy project means a proposed energy-generating facility or group of facilities, which may be located on up to three sites.]

The above statute concerns the MEP. Exempting the MEP exempts up to six 600 MW generation facilities. Each of these facilities will emit approximately 5.3 million tons of carbon dioxide (CO2) annually, nearly 32 million tons annually if all six were constructed. / The generating units of the MEP are being proposed as capture ready. Excelsior Energy has repeatedly stated that the MEP will be ready to capture 30% of CO2 when mandated by law. 10% of CO2 escapes in the Carbon Capture and Sequestration (CCS) process. That equates to 80% (4.24 million tons per facility or 25.44 million tons total) of CO2 still contributing to global warming.

Please keep in mind the statements of the Department of Energy (DOE) in Appendix A2 of the MEP s Draft Environmental Impact Statement (DEIS). In this four-page section, the DOE clearly states that CCS is not technically or economically feasible for the MEP.

The Public Utilities Commission has determined that the costs associated with the MEP are too high and risky for Xcel s ratepayers. Adding CCS to the MEP raises the cost of the electricity produced by up to 40%. / Excelsior Energy wants their project to be exempt from meaningful climate control legislation because of their knowledge and the DOE s findings that it is not feasible for the MEP to capture CO2.

Excelsior Energy has been on the receiving end of unprecedented special legislation and monetary handouts for the Mesaba Energy Project. Its time to use common sense and say NO to more legislation that would encourage this project to move forward, a project without any hope of producing cheap or clean energy."

Amanda Nesheim, Big Fork, MN

"I commend the committee on some excellent next generation standards--,however if Big Stone 2 and Mesaba are allowed to go on as planned (projected to emit 5.1 million tons of CO2 per year) we will never reach our goal of lowering emissions 80% by 2050 (as recommended to avert catastrophic change). Please remove the statement that grandfathers in this old technology and re-consider how to give these power plants the incentive to become next generation plants too."

Julia Nerbonne, Minneapolis, MN

"Mesaba Units I and II will emit 10.6 million tons/year of CO2, and carbon capture equipment will not be installed until mandated by law. But, the Minnesota Geological Survey has recently concluded that there is a very low probability of success in confirming suitable conditions for deep geologic sequestration of CO2 in Minnesota, and some CO2 escapes anyway. Existing technology could capture only 30% of the CO2, and the necessary equipment and pipeline has been estimated at $1 billion. The DOE has concluded that: carbon capture and sequestration (CCS) could increase the cost of electricity by as much as 40%. If the CO2 could be sold for enhanced oil recovery, the revenues would be grossly insufficient to recover the costs of CCS; and without a PUC order incorporating CCS costs within the power purchase agreement, Mesaba would not be economically viable. Even if CCS were implemented, Mesaba would still be adding 8 million tons/year to Minnesota's GHG emissions. We should prevent utilities from making long-term investments in high-carbon-generation technology. This should be immediate - and it should apply to all baseload projects not already in operation."

Susan Hutchins, Grand Rapids, MN

"How has money and profit become the main consideration in decision making? The idea of exempting the Mesaba Energy project from CO2 emmision standards is shocking. Remember, it's your children and grandchildren who will pay the price of this stupidity with their health and their lives. I was out of town and therefore this email did not make the deadline, but I doubt that input from people matters much anymore. Big business is the god of our times."

Celeste Kanli, Grand Rapids, MN

"I find it inconceivable that the Minnesota legislature (not exactly a group of emission scientists) can decide that the Excelsior/Mesaba Energy can be exempt from the power company emissions standards. I also find it inconceivable that the legislature can write its own definition of the coal gasification as "innovative energy" as it pertains to Excelsior/Mesaba Energy. Excelsior/Mesaba Energy has no plans to sequester any of its CO2 atmospheric emissions, and thus will be a major atmospheric polluter. In these days of increases awareness and knowledge of greenhouse gases and climate change, Excelsior/Mesaba Energy should not be exempt from the emissions performance standards; rather, Excelsior/Mesaba Energy should be held to the highest, scientifically monitored standards. Our future, and that of our grandchildren, depends on it!

William E Berg, Bovey, MN

ES 3: Efficiency Improvements, Re-powering and Other Upgrades to Existing Power Plants

"Switching From Coal to Natural Gas for Electric Power. I was happy to see that this was not included in the recommendations (that I could find). While natural gas reduces the amount of CO2 emissions, it substitutes this for increased water vapor that is a stronger greenhouse gas than CO2. Furthermore, it causes a significant increase in cost to produce electricity."

Richard J. Petschauer, Edina, MN

"The report doesn't mention whether life cycle emissions from biomass are considered in the repowering scenario with biomass co-firing. If they are not, the GHG savings from this strategy could be reduced. In addition, the land requirements for this strategy should be considered in the context of the land requirements for other strategies in the report."

P Reich (Regents Professor, Dept of Forest Resources, U of Minnesota)
E Nater (Professor & Department Head, Dept of Soil, Water and Climate, U of Minnesota)
S Hobbie (Associate Professor, Dept of Ecology, Evolution, and Behavior, U of Minnesota)
J Espeleta (Research Associate, Dept of Soil, Water and Climate, U of Minnesota)
C Fissore (Research Associate, Dept of Soil, Water and Climate, U of Minnesota)
L Olabisi (Research Associate, Ecosystem Science and Sustainability Initiative, U of Minnesota)
A Ek (Professor & Department Head, Dept of Forest Resources, U of Minnesota)

"This option as drafted involves requiring utilities to evaluate their existing generating units for opportunities to improve their emissions profile through a variety of options efficiency improvements, the addition of biomass or other fuel changes, or the additional of carbon capture technology. However, the only option that was considered quantifiable was the option of adding biomass. Initially, the Energy Supply TWG considered adding 8% biomass to coal plants. Later, it decided that this might not be realistic given supply constraints and reduced it to 1% biomass. However, because the MCCAG had already voted on the 8% option, the numbers in the final report assume the CO2 savings and financial costs associated with the 8% option, even though the language on page 4-5 refers to the 1% biomass option. However, it is unclear to what extent the analysis overestimates reductions, since the other unquantified aspects of the policy (like improving efficiency) could increase emissions reductions."

Barbara Freese, Union of Concerned Scientists, Minnesota Center for Environmental Advocacy, Izaak Walton League of America -- Midwest Office, Fresh Energy, Global Green Energy LLC, Institute for Agriculture and Trade Policy, Clean Water Action, Saint Paul, MN

ES 4: Transmission System Upgrading, including Reducing Transmission Line and Distribution System Losses

"EX-10 and ES-4 assumes transmission reduces CO2 generation, which is false, because CapX 2020 would facilitate coal and increased CO2 emissions."

Carol A. Overland, Red Wing, MN

ES 5: Renewable and/or Environmental Portfolio Standard

"In addition, the State of Minnesota must encourage and/or regulate utilities to import additional hydroelectric power in place of coal or nuclear sourced electric power, whenever the choice is available without building additional dams. Furthermore, it is necessary to evaluate the potential for upgrading existing in-state hydro generation facilities"

Tom Casey, West Metro Global Warming Action Group, Mound, MN

"Facts against Mesaba exemption from CO2 emission standards. Mesaba 1&2 will emit 10.6 million tons/yr.CO2 as is. CC equip. not installed until needed by law. CCS existing tech. capture 30% only,equip.est. $ 1 billion. Not economical. 8 million tons/yr add to Mn.GHG emissions even with CCS. Conflicts with goal reduction of MN. GHG emissions. Protection is denied to citizens when Companies are exempt."

Darrell and Delores White, Bovey, MN

"Burning biomass and burning garbage is NOT renewable or sustainable and it has very high emissions. Minnesota must eliminate burning -- it has no part in a CO2 emissions reduction plan."

Carol A. Overland, Red Wind, MN

"Estimations of the GHG savings from replacing coal and natural gas electricity generated out-of-state with renewable electricity may be low. The report appears to underestimate the proportion of out-of-state electricity that comes from coal. This has the effect of making renewable electricity generation seem less important as an emission reduction strategy than it actually is."

P Reich (Regents Professor, Dept of Forest Resources, U of Minnesota)
E Nater (Professor & Department Head, Dept of Soil, Water and Climate, U of Minnesota)
S Hobbie (Associate Professor, Dept of Ecology, Evolution, and Behavior, U of Minnesota)
J Espeleta (Research Associate, Dept of Soil, Water and Climate, U of Minnesota)
C Fissore (Research Associate, Dept of Soil, Water and Climate, U of Minnesota)
L Olabisi (Research Associate, Ecosystem Science and Sustainability Initiative, U of Minnesota)
A Ek (Professor & Department Head, Dept of Forest Resources, U of Minnesota)

"The MCCAG Report Assumes RES Costs That are Far Too High The MCCAG analyzed the costs associated with the Renewable Electricity Standard (RES) enacted by the state in 2007. The main reason to look at the cost of this already-enacted law was to model the costs of complying with a cap and trade program. During the course of the MCCAG process, the estimated cost of the RES fluctuated wildly. At the December 5 meeting it was estimated to cost about $2 billion over the study period (up to 2025). At the January 10 meeting the cost had dropped over three billion dollars to a negative $1.675 billion. At the January 24 meeting, the cost had skyrocketed and the RES was estimated to cost $7.5 billion dollars, and this number persists in the final report. The cost/ton of reductions associated with the RES similarly bounced from $20/ton to a negative $13/ton and landed at a positive and highly implausible $56/ton. Had there been another meeting, it is likely these cost numbers would have dropped back down.

This high cost for emissions savings from the RES runs counter to a great deal of other analysis of RESs. A recent detailed study of RESs by the Department of Energy s Lawrence Berkeley National Laboratory shows that RES standards are extremely cost effective and sometimes reduce electric rates. The study looks at results from 28 state or utility-level RES cost studies completed since 1998. It finds that on average state standards will result in a monthly electric bill increase of just 38 cents for a typical residential household. Since the study does not analyze the effect of increased renewable energy use on natural gas markets, which several studies have found would lower demand and prices by increasing competition, the overall energy bill impacts from state RESs would likely be even lower. (This study if further described at the website of the Union of Concerned Scientists.)

The exorbitant RES cost estimate embedded in the final report also runs directly counter to the Integrated Resource Plan recently submitted to the PUC by Xcel Energy. Xcel provides half the retail electric power in the state and bears a disproportionate share of the RES costs given its higher obligations under the law. If the RES actually cost $7.5 billion to implement over the study period, more than half of that cost should be appearing in Xcel s IRP. In fact, Xcel projects that complying with the RES (assuming a production tax credit in place until 2015) will save it about half a billion dollars compared to a no-wind scenario. Even when Xcel models a scenario with no production tax credit, the cost of the RES scenario is only marginally higher than the no wind scenario (rising from $60.667 billion to $60.891 billion). [Xcel Energy 2007 Resource Plan, page 5-12.]

The projection of RES costs is a complex matter, and as the history of the MCCAG estimates shows, changing assumptions can make it dramatically different. There are at least two problematic underlying assumptions that contribute to the MCCAG RES cost estimate being so high:

(1) Wind cost estimate unrealistically high. There was a tremendous increase in the estimated cost of wind power between the November 2007 analysis and January 2008, rising from $50.60 per megawatt hour to $153.7/MWh (see page G-63). The component of wind costs responsible for this leap is the capacity cost for wind, which jumped from $38.9/MWh to $131.3/MWh. This clearly had a huge impact on the analysis because it now estimates that wind power costs almost three times more than coal power, which is far from the case. The reason this price went up so high apparently relates to a decision to reflect a reduced capacity credit for wind in order to reflect its intermittent nature. However, the reason Minnesota passed such an aggressive RES in 2007 was because the state' s very detailed Wind Integration Study showed that adding this quantity of wind to the system could be done with only a modest additional cost to integrate the wind into the current grid. In other words, that study showed that wind s intermittent nature, while not irrelevant, adds to overall costs only minimally. The MCCAG report, by contrast, appears to assume that wind s intermittent nature triples its cost.

Here again there is a dramatic contrast between the assumptions embedded in the MCCAG report (which assume wind costs of $153.70/MWh) and those made by Xcel in its IRP. Xcel projects far lower wind costs of $58.50/MWh for 2010-2015 and of $78/MWh after 2015 when it assumes the production tax credit won t be available. Xcel s estimates include an ancillary service cost based on the Minnesota wind penetration study of 2006. [Xcel Energy 2007 Resource Plan, page 5-12]

(2) New renewables are compared to old coal plants, not new ones. Another analytical problem with the RES calculation is that the cost of new renewables are compared solely to the cost of existing coal, rather than to the much higher cost of new coal plants. We know that the RES has reduced the demand for new coal plants from Minnesota utilities. GRE was formerly a partner in the Big Stone II plant and it cited the RES as among the reasons why it pulled out of that project. Similarly, Xcel formerly had a great deal of new coal capacity in its Integrated Resource Plan.

In a final conference call discussion held by the MCCAG to discuss the draft report, there was general acknowledgment that the wind cost number was very high. However, with the process at its end, this issue was not resolved.

The extremely high cost of the RES is important because the RES is an important part of the cost curve that is fed into the computer model that determines what it would cost Minnesota to comply with a cap and trade program. Moreover, because the cap and trade modeling process derived cost curves for our regional trading-partner states by adjusting the Minnesota cost curve according to the carbon intensity of the various state economies. This means that the impact of overestimating the cost of an RES is amplified throughout the region. While it is difficult to know the impact of this cost overestimation on the cap and trade numbers generally, it could be substantial.

When additional modeling is done under the Midwest Governor s Association process, it is important that it use a more realistic estimate of RES costs".

Barbara Freese, Union of Concerned Scientists, Minnesota Center for Environmental Advocacy, Izaak Walton League of America -- Midwest Office, Fresh Energy, Global Green Energy LLC, Institute for Agriculture and Trade Policy, Clean Water Action

ES 6: Nuclear Power Support and Incentives

"The Next Generation Energy Act of 2007 (Chapter 136, 2007 Session Laws) sets energy policy goals that: (1) the per capita use of fossil fuel as an energy input be reduced by 15 percent by the year 2015, through increased reliance on energy efficiency and renewal energy alternatives; and (2) 25 percent of the total energy used by the state be derived from renewable energy resources by the year 2025. (Minn. Stat. 216C.05, Sub. 2). This is not good enough. Timelines must be accelerated and goals must be elevated. The citizens of Minnesota, through their elected representatives, must consider global warming as the world emergency it really is. Solving the global warming crisis requires the highest allocation of financial, scientific, and other resources that our world of nations has ever seen beyond the resources devoted to our efforts in world wars, the Marshall Plan, or the Apollo Project. The solution lies partly in research and development of renewable energy resources. Nuclear energy is a **devil s bargain** - a target for terrorists and a dirty, linear chain of events from mining to waste disposal. The solution also requires personal involvement and sacrifice. Citizens must adopt personal conservation measures set forth by our elected leadership and proactively practice sustainable lifestyle choices."

Tom Casey, West Metro Global Warming Action Group, Mound, MN

"This is probably the single most important way to reduce CO2 emissions and coupled with more plug-in electric/hybrid automobiles has the promise to do more than all the other proposals combined covered in the MCCAG report. Furthermore, it will result in decreased costs of electricity, especially compared to natural gas. This should be given a very high priority with a shorter time frame for a number of nuclear plants. Government loans should be given to utility companies with interest and payback delayed until production begins."

Richard J. Petschauer, Edina, MN

"Any further analysis of increasing nuclear power to reduce GHG emissions should include a full cradle to grave GHG accounting . The mining, transport, and refining of Uranium is incredibly fossil fuel intensive. Furthermore, nuclear power stations often need supplemental power from the grid to operate safety systems, so this added stress to grid must also be accounted. Finally, the issue of nuclear waste can not be ignored simply because it does not emit GHG. "

Matthew Tyler, Finland, MN

"The option in the table for Nuclear Power (ES-6) was unanimously approved by the group with clarifications. This group was a mixture of business and environmental interests, so I think this represents an indication that the group thought this was an option that could not be ignored. The clarifications were simply that we needed to assure ourselves of the safety of this. I believe this is based on a lack of understanding of nuclear power. I would recommend a book by Gwyneth Cravens entitled "Power To Save The World: The Truth About Nuclear Energy" to answer any questions concerning safety, nuclear waste, etc.In addition, there is a memo from the Energy Supply Technical Working Group (ES-TWG) of the MCCAG, which was prepared as part of the final report of this working group, that shows the potential cost advantages of nuclear power. This is documented on the MCCAG website at http://www.mnclimatechange.us/ewebeditpro/items/O3F14774.pdf . On page 5 of this memo there is a table called Levelized Costs of New Electric Generating Capacity. This table makes it clear that new nuclear power is cheaper than any of the viable alternatives except pulverized coal. Pulverized coal represents a coal plant with no improvements to reduce CO2 emissions...

I still believe that nuclear power is the best method to have a truly substantial impact on greenhouse gas emissions. Wind power can never be more than a minor component because of the unpredictable nature of the power source. If cheap methods of storage can be developed, wind power can be a major contributor. Research has been going on for years for cheap and effective ways to do that. Coal power with carbon capture and sequestration will always be more expensive than nuclear and we will still have the massive amounts of toxic combustion residue to deal with. I would recommend a change in the Renewable Energy Standard to accommodate nuclear power.

Jerry Hinderman, North Oaks, MN

"Nuclear power - this recommendation does not consider the magnitude of the full life-cycle CO2 emissions of nuclear."

Carol A. Overland, Red Wing, MN

ES 8: Advanced Fossil Fuel Technology Incentives, Support, or Requirements, including Carbon Capture and Storage

"Mesaba energy project should not be exempt from pollution emission regulation. We need to move forward and not be implementing 100 year old technologies. Renewable energy is the only way forward if we want to keep our planet from catastrophic changes."

Chad Johnston, Bovey, MN

"No additional fossil fuel power plants (such as the planned Big Stone 2 and the Mesaba IGCC plants) should be allowed unless they have a functioning carbon dioxide capture and storage/re-use (CCSR) system functioning from their first day of operation. To curb major greenhouse gas emissions and build the infractructure for a sustainable future, we need to be putting our energy sector financial resources into renewable energy (e.g., wind and solar, with energy storage) and into retrofitting existing fossil fuel plants with CCSR technology. There are several "carbon capture" technologies currently available at pilot or near-commercial scale around the world that could be used. (See, for example, the Carbon Capture Journal website at http://www.carboncapturejournal.com/.) These include CO2 capture using chilled ammonia, monoethanolamine, other amine solvents, Mitsubishi Heavy Industries' proprietary solvent (which has been in commercial use in a urea fertilizer plant in Malaysia since 1999), and CO2 cooling/liquification (Denis Clodic, et al., France.) Descriptions of systems that collect and store carbon-neutral renewable energy (wind, solar, hydroelectric, etc.), and that can convert captured CO2 to useful products in a carbon-neutral, energy efficient manner, are described in international patent applications PCT/US2008/051533 and PCT/US2008/050805, which will be published about mid-August, 2008. I am vey disappointed that the MCCAG was unable to present clear recommendations on implementing Policy Option ES-8, since the final report states (page 37), "Emissions associated with electricity generation and imports to meet in-state demand is projected to be the largest contributor to future emissions growth."

Dr. Dale R. Lutz, Maplewood, MN

"Open Letter to Minnesota Legislature SUBMISSION TO MINNESOTA LEGISLATURE REGARDING MINNESOTA LEGISLATURE CLIMATE CHANGE ADVISORY GROUP'S RECOMMENDATION TO EXEMPT A PROPOSED COAL-FIRED POWER PLANT, EXCELSIOR ENERGY, FROM CO2 EMISSION RESTRICTIONS

I was informed that *Minnesota Climate Change Advisory Group (MCCAG) is recommending to the Minnesota Legislature that *Excelsior Energy's proposed coal-fired power plant (supposedly *IGCC) can go ahead and burn as much CO2 as they want. According to MCCAG, this coal-fired plant should be exempt from any restrictions on its CO2 emissions.

It would be in the interest of each one of us - wherever we are - not to pursue fossil fuel burning in any of its forms or shapes. Without environment there is no economy. Fossil fuel burning will not only irreparably damage your local environment - I mean it is your Minnesota. Wouldn't you want it to be beautiful and livable? - but it will add *GHG to our collective planetary atmosphere.

Imagine YOUR Minnesota being ravaged with Excelsior's fossil fuel operation not for the sake of producing your energy it was already established that Minnesota didn't need more energy, especially not from a coal-fired plant but for its own sake. Excelsior's survival method in No Demand / No Customer situation in Minnesota was to force a local utility into buying its dirty power. The utility said No. No means No. Really!!! (PUC rejects Iron Range power plant project Pioneer Press Nov 1, '07)

Even if you needed to produce more energy, why would you ever go with the environmentally destructive technologies especially those based on fossil fuel burning? To award public moneys to a fossil-fuel burning plant which is proposing to destroy local and global environment by producing energy no one needs is tragic.

It is unbelievable that this Excelsior's proposed coal-fired plant received millions from the Renewable Development Fund. When did fossil-fuel burning, which is choking our Planet to death, become renewable??? This question, though, is not meant to trigger the blah blah on IGCC, *ZLD and *CCS. I am really not interested in indulging in false hopes which are propping Ole King Coal and driving each one of us to extinction. Gassing the planet with fossil fuel burning (includes nuclear) is a job almost completed. What more is there to be said about fossil fuel burning than that we need to abolish it immediately?

Many within Minnesota Climate Change Advisory Group do not agree with the MCCAG final decision, which is recommending to Minnesota Legislature to exempt Excelsior's proposed coal-fired plant from CO2 emissions restrictions. Many members of MCCAG are representatives from local community, faith and environmental groups who joined hoping to ensure the wellbeing of their environment. I believe that they participated in a stakeholder consensus building process, which was rigged from start.

It is safe to conclude this because among other things, the State of Minnesota already invested millions of public monies into Excelsior's cause, gave this corporation power to exercise eminent domain meaning to kick people off their land for new transmission lines and exempted Excelsior from public hearing in determining whether power is needed. (Coal gasification arguments Nov 21,'03 MPR) Also, Excelsior's VP, Richard Stone acts as a member of the MCCAG's Energy Supply Technical Working Group, which convinced the MCCAG to recommend to the Governor that this project be allowed to proceed. (Letter to Legislators Feb 18, '08 Citizens Against the Mesaba Project http://www.camp-site.info/letter.html) Many of Excelsior's executives have been involved in companies that were fined $25 million for manipulation of California's energy market. (Public Citizen, Nov 10, 2003 Minnesota's Excelsior Energy to Receive $800 million in Loan Guarantee in Energy Bill). They also have ties to NRG Energy Inc. which filed for bankruptcy in 2003 taxing its parent company Xcel Energy Inc. with $752 million (NYTimes May 15, 2003 NRG Energy Files for Bankruptcy Protection). Xcel Energy is a local utility in Minnesota that refused to buy dirty energy from Excelsior's proposed coal-fired plant. Xcel owns two nuclear plants involved in controversy over their nuclear waste storage. More on Xcel: http://en.wikipedia.org/wiki/Xcel_Energy

Dear Minnesota Legislators, your decisions about fossil fuel burning in Minnesota are of concern to all of us. I live in Ottawa, Ontario and I am very concerned about Excelsior's proposed coal-fired plant in your state. This is so because accumulation of Greenhouse Gases in this planet's atmosphere through fossil fuel burning sees no boundaries. It affects us all however close or far we happen to be from those coal-fired plants. In addition, Excelsior coal-fired plant wastewater would discharge into the Upper Mississippi River watershed. (Excelsior Energy Announcement Agreement to undertake major water quality improvement program - paragraph 2 - January 21, '08) http://energyfacilities.puc.state.mn.us/documents/16573/Excelsior%20Press%20Release-ZLDWQ.pdf Ottawa's watershed is part of the Mississippi watershed. Billions tons of Excelsior's heavy metals would end up in this watershed. Excelsior's heavy metals are directly connected to the wellbeing of my unborn child. Brain damage and birth defects result from ingesting water, food and air contaminated with heavy metals.

Excelsior fled from its previously selected East Range site because of the Lake Superior watershed requirement for Excelsior to have Zero Liquid Discharge wastewater treatment facility (Excelsior Energy: Environmental Consciousness or Desperation? January 25, 2008, Ed Anderson Co-Chair, Citizens Against the Mesaba Project CAMP http://www.camp-site.info/ scroll down) At the end, even if it was implemented, Zero Liquid Discharge facility still needs to find dumping grounds for hazardous solid waste, which is byproduct of coal-fired plant wastewater treatment. Your decisions concern Life on this Planet, including your own life. The times when we could observe the smoke of burning bodies from our green soccer fields is gone because the fire is catching on. Why fan the fire? Extinguish it starting with Excelsior! FYI: http://www.camp-site.info/ http://www.mncoalgasplant.com/ Ivona Vujica ivujica@gmail.com Ottawa. IGCC stands for Integrated Gasification Combined Cycle. Read more about IGCC http://www.energyjustice.net/coal/igcc/factsheet.pdf ZLD stands for Zero Liquid Discharge It is a factory on its own: http://www.hpdsystems.com/en/industries/zeroliquiddischarge/ http://www.hpdsystems.com/en/industries/industrysolutions/power/

Instead of forsaking your water to the private water treatment interests, keep it clean and public. Don't build fossil fuel burning plants. Go green. Invest in a mix of renewable technologies for every building in Minnesota. CCS stands for Carbon Capture and Sequestration. In addition to dumping CO2 in the atmosphere, CCS approach would also dump it in the ground. But why pursue CCS when the only recourse to our collective survival is abolition of fossil fuel burning. People are ready for the green economy. GHG stands for Greenhouse Gases such as CO2 and Methane Minnesota Climate Change Advisory Group http://www.mnclimatechange.us/ewebeditpro/items/O3F15517.pdf. What is Excelsior Energy? http://www.excelsiorenergy.com/mesaba/description_frame.html

Later Submission: Correction regarding info on Mississippi watershed While Ottawa, Ontario is located in the Mississippi Watershed of Eastern Ontario, Mississippi watershed in Eastern Ontario is different from the Mississippi watershed in Minnesota. Located in the Upper Mississippi watershed, Excelsior Energy would be discharging its waste and cooling water close to the source of the second longest river in the U.S., which starts at Lake Itasca in Minnesota and ends at Gulf of Mexico, passing through major U.S. cities. Billions tons of Excelsior's heavy metals would end up in this watershed. Heavy metals impact the wellbeing of unborn children. Brain damage and birth defects result from ingesting water, food and air contaminated with heavy metals. Corrected version available at : http://floodiceorfire.wordpress.com/2008/04/25/excelsior/"

Ivona Vujica, Ottawa, Canada

ES Other Comments

"Near the bottom of the table is a line that shows the cost and effectiveness of the Renewable Energy Standard that has been enacted in Minnesota. The cost of this standard is $7.5 billion between 2008 and 2025. And the cost per ton of CO2 emissions reduced is $56/ton. This is a cost based mostly on importing wind power. It is difficult to accommodate this power in the grid because it is not base load, that is, it cannot be predicted when the wind will blow and the wind power generated at night may not be usable when the load requirements are significantly less.

The recently enacted Consumer Incentive Plan (CIP) requires annual energy savings of 1.5%. If these savings are actually achieved it will be even more difficult to accommodate this wind power because existing power plants will have to be cycled off and on or idled. These plants produce power at a significantly lower cost than wind power and there are other costs of cycling these plants in addition to the cost differential of the basic source. These costs have not been adequately taken into account in this analysis."

Jerry Hinderman, North Oaks, MN

"New NASA satellite studies and others show increasing evidence that the fine particulates of wood combustion/wood smoke and others contribute heavily to climate change. This is because pollution in clouds thins cloud formation and interferes with the seeding of rain and snow. Burning biomass is not clean energy. Wood may be green, but the combustion is the problem. The fine particulates harm the air, our lungs, water, food supply and the planet. The dioxins in wood smoke are bioaccumulative and are implicated in reproductive defects. PLEASE CONTACT me, Julie Mellum, 612-926-109, for more information. Or see www.burningissues.org.

Julie Mellum, President, Take Back the Air, Minneapolis, MN

"I am concerned that giving the Mesabe project an exemption from emission standards will allow pollutants into the atmosphere resulting in global warming at a time when it should be our primary concern."

Kenneth Hamilton, Waseca, MN

"Sierra Club MCCAG Comments. Energy Supply Sector. Author: Dale Lutz.

Part 1 of the report, in the middle of page 37 states: Emissions associated with electricity generation and imports to meet in-state demand is projected to be the largest contributor to future emissions growth, Fig. 1-2 on page 38 estimates the electricity (consumption based) contribution to gross GHG [greenhouse gas] emissions to increase from 40 MMtCO2e [million metric tons of CO2 equivalent] in 2000 to about 65 MMtCO2e by 2025. The figure also shows that this sector is expected to produce the largest absolute increase in gross GHG emissions between now and 2025.

Executive Summary Figure EX-3 (part 1, page 15) assumes completion of the Big Stone 2 coal-fired plant and the Mesaba IGCC coal-fired power plant (without arguing for or against them.) These facilities are projected to produce 5.1MMtCO2e/yr (million metric tons of CO2 equivalent per year.) It also assumes backing down of other facilities to match demand if these plants come on line. The "rule of holes" states that when you find yourself in a hole, the first thing you should do is stop digging yourself deeper. Since coal-fired power plants are the largest single source of carbon dioxide emissions, one of the most obvious ways to address climate change is not to build or expand new coal-fired power plants, which commit us to carbon emissions from these facilities for decades.

Recently NASA Scientist Dr. James Hansen sent a letter to Governor Pawlenty expressing grave concerns around global warming related to the Big Stone II coal plant proposal sharing statements such as, A direct implication is that we cannot be aiming for a 50, 80, or 90 percent reduction of emissions. We must transition over the next several decades to practically zero net CO2 emissions. Thus our energy focus must be to develop carbon-free energy sources and energy efficiency.

The Sierra Club is opposed to new coal fired power unless projects can be demonstrated to mine coal responsibly, burn it cleanly, and does not contribute to global warming. Right now, coal meets none of these criteria. While IGCC designs may be more compatible with carbon capture and storage (CCS or "sequestration"), no approach currently exists to do so on a commercial basis. All new coal plants should be built with the potential to sequester CO2 Big Stone II and Mesaba have not demonstrated a realistic capacity to do so. Aside from these considerations, these projects have not adequately demonstrated that they are needed. Big Stone II and Mesaba plants should not be allowed to go forward without having carbon capture and sequestration/re-use in place and operating as soon as the plants are brought on-line.

This approach is at least partially supported in Appendix G, Energy Supply Sector Policy Recommendations, under Policy Number ES-8, which the Minnesota Climate Change Advisory Group (MCCAG) voted unanimously as "recommended for further study." The policy goals for ES-8 state that, "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 CO2 emissions, while producing energy that is both affordable and reliable." The Timing portion of the goal statement says, "By 2020, the Upper Midwest Region (Minnesota, Wisconsin, and North and South Dakota) should have at least two IGCC [Integrated Gasification Combined Cycle coal plant] projects with carbon capture and storage through design, construction, and into full operation." (One of the specific IGCC demonstration projects mentioned is Excelsior Energy's Mesaba project in northeastern Minnesota.) This will require plant re-design, as well as establishing and implementing a credible plan for dealing with the captured CO2 (including associated legislation and infrastructure.) In the meantime, the Sierra Club believes that any additional electricity generation capacity added should be carbon-neutral with priority placed on energy efficiency measures and renewable energy (such as wind and solar - either from commercial providers or as distributed generation by individual consumers.)

The ES-8 "Implementation Mechanisms" section also mentions "IGCC in conjunction with renewable energy, such as wind power and/or hydrogen production," possibly referring to Xcel Energy's Wind to H2 project with the National Renewable Energy Laboratory in Colorado. Sierra Club is opposed to increased electricity generation from nuclear power. Although nuclear power produces less CO2 than fossil alternatives, nuclear power is not safe, affordable, or clean with currently available technology and practice. Mining uranium risks workers' health and creates toxic residues. Clean energy resources are sufficient to address climate change and are cheaper than nuclear power. In addition, the huge investment to bring additional nuclear facilities online would siphon capital from much more cost-effective uses of financial resources, especially investments in efficiency.

The Minnesota Climate Change Advisory Group (MCCAG) voted unanimously to "recommend for further study" of Energy Supply working group proposal ES-6, "Nuclear Power Support and Incentives." According to an April 16, 2008, article in the St. Paul Pioneer Press (page 1C), Xcel Energy said "it wants to extend the lives of its two reactors at the Prairie Island nuclear power plant near Red Wing by another 20 years and also boost their power generation. That would require approval by the Minnesota Public Utilities Commission to allow Xcel to store more spent radioactive fuel in containers on the grounds of the plant, which is next door to the Prairie Island Mdewakanton Dakota community." An article in the same newspaper the next day (April 17, 2008, page 2C) stated that "The Prairie Island Indian Community Tribal Council said Wednesday that it has 'very serious concerns' about a proposal by Xcel Energy to extend the license of its Prairie Island nuclear power plant another 20 years. ... 'We're extremely concerned about the prospect of re-licensing the Prairie Island plant, or any nuclear power plant, at this time,' Prairie Island Tribal Council President Ron Johnson said in a statement." This brings up issues of public resistance to nuclear power, nuclear waste disposal, nuclear proliferation, susceptibility to terrorist attacks, and environmental justice for groups disproportionately affected by nuclear waste, such as Indigenous populations like the Prairie Island Mdewakanton Dakota community.

Sierra Club requests any further study of nuclear power includes at a minimum: inclusion of groups disproportionately affected by nuclear power plant siting and waste storage; siting, risk, and costs associated with waste disposal; the impact on nuclear energy prices with the repeal of the Price-Anderson Act which acts as a government subsidy by severely limiting the liability of nuclear power plant owners in the case of accidents, and the level of government subsidy (including existing subsidies like the Price-Anderson Act) required to make nuclear energy cost-competitive with other energy sources.

Energy Supply policy proposal ES-3, "Efficiency Improvements, Re-powering, and Other Upgrades to Existing Plants," was unanimously approved as an 8% (later revised to 1%) biomass co-firing at coal-fired power stations. This proposal was modeled such that "Wood wastes and forest residues are the major form of biomass to be used, at a flat price of $2.5/million British thermal units (MMBtu)", in 2005 dollars. The Sierra Club is concerned that this policy would encourage increased deforestation and illegal logging. The study apparently does not consider the additional vehicle emissions from transporting the forest residue to the coal-fired plants. Please see Sierra Club s comments on the Agriculture, Forestry, and Waste Sector in which we share more detailed concerns around biomass.

If, after all energy efficiency measures are met and renewable energy supply is exhausted, actual need for a new coal-fired power plant can be adequately demonstrated, (which we believe is an incredibly difficult case to make considering changes in investor status, as well as Department of Commerce testimony suggesting adequate need was not demonstrated in the Big Stone II proposal as two examples.) we require that the coal-fired plants must also have in place the best available pollution control equipment, to avoid release of soot and carbon particulates that contribute to global warming and serious health and environmental hazards, as well as the various toxins associated with wood smoke at uncontrolled facilities. Furthermore, there is increasing competition for "wood wastes and forest residues," as described in the St. Paul Pioneer Press article from April 6, 2008 (page 7D), titled "Once waste, sawdust fetches big price." The subtitle reads, "Sawmill byproducts find a ready market among dairy farmers, pallet makers and other manufacturers." The article states that these sawdust buyers "are paying up to $50 a ton or more. That's double what they paid a year ago, some say." A sawmill operator is quoted as saying, "It's gotten to the point where wood shavings, which are popular with horse farms, are worth more than the lumber. ... We use every part of the tree. It's become so valuable you can't afford to not sell everything."

Energy Supply proposal ES-1, a "General Performance Standard," was passed by the advisory group by a simple majority, with 16 objections. The policy goal was to "prevent utilities from making a long-term financial commitment to base-load generation plants with carbon dioxide (CO2) emissions in excess of 1,100 pounds of CO2 per megawatt-hour (MWh)." However, "At its last meeting, the MCCAG decided that this option would not apply to the planned Big Stone II and Mesaba coal plants. Therefore, no benefits or costs are ascribed to this option." We recommend that Big Stone II and Mesaba be required to meet this standard. MNCCAG fails to realize the impact of locking Minnesota into decades of energy generation by allowing current coal-fired power plant proposals, namely Big Stone II and Mesaba, to be excluded from global warming pollution reduction recommendations. Failing to address these proposals will result in significant increases of CO2 emissions which directly contradicts the state s goal to reduce emissions. The cost analysis applied to Big Stone II and Mesaba only included construction and operation costs, thus it does not take into account the increasing cost of coal and potential for costs around carbon regulation. Even without the full analysis of high social, environmental, and financial costs, had MNCCAG applied the expected emissions and cost of these projects to the Final Reports recommendations, the state would be saving a tremendous amount of pollution and money in its plan for addressing global warming."

Cesia Kearns, Sierra Club, Minneapolis, MN

"Exemption of Big Stone II and Mesaba is beyond the scope of the charge of the group, and contrary to the charge to devise a plan to REDUCE CO2 emissions: The report assumes exemption of two large CO2 emitters, Big Stone II and Excelsior Energy s Mesaba project. This exemption is stated, but the statute provides only for the group to: (7) evaluate the option of exempting a project from the prohibitions contained in section 216H.03, subdivision 3, if the project contributes a specified fee per ton of carbon dioxide emissions emitted annually by the project, the proceeds of which would be used to fund permanent, quantifiable, verifiable, and enforceable reductions in greenhouse gas emissions that would not otherwise have occurred. Minn. Stat. 216H.02, Subd. 4(7)"

Carol A. Overland, Red Wing, MN