

# Appendix G Energy Supply Policy Recommendations

## Summary List of CCAC-Recommended High Priority Policy Options

	Policy Option	GHG Reductions (MMtCO <sub>2</sub> e)			Net Present Value 2007–2020 (Million \$)	Cost-Effectiveness (\$/tCO <sub>2</sub> e)	Level of Support
		2012	2020	Total 2007–2020			
	<b>Energy Supply</b>						
ES-1	Environmental Portfolio Standard (Renewables and Energy Efficiency)						UC
	Efficiency/Conservation	0.03	0.92	5.4	–\$79	–\$15	UC
	Renewable Energy	0.0	1.6	5.5	\$53	\$10	UC
ES-2	Renewable Energy Incentives and Barrier Removal	<i>Not Quantified Separately (see ES-1 and ES-4)</i>					UC
ES-3	Research and Development (R&D), Including R&D for Energy Storage and Advanced Fossil Fuel Technologies	<i>Not quantified</i>					UC
ES-4	Incentives and Barrier Removal for Combined Heat and Power (CHP) and Clean Distributed Generation (DG)						UC
	Distributed Renewables	0.03	0.10	0.8	\$16	\$21	UC
	Combined Heat and Power	0.2	0.7	5.0	\$81	\$16	UC
ES-5	Incentives for Advanced Fossil Fuel Generation and Carbon Capture and Storage or Reuse (CCSR)						UC
	Reference Case	0	1.0	4.5	\$135	\$30	UC
	High Fossil Fuel Scenario	0	5.2	24.4	\$733	\$30	UC
ES-6	Efficiency Improvements and Repowering of Existing Plants	<i>Not Quantified</i>					UC
ES-7	Demand-Side Management	<i>Not Quantified Separately (see ES-1 and RCII-1)</i>					UC
ES-8/9	Market-Based Mechanisms to Establish a Price Signal for GHG Emissions (GHG Cap-and-Trade or Tax)	<i>Not Quantified</i>					UC
ES-10	Generation Performance Standards or GHG Mitigation Requirements for New (and/or Existing) Generation Facilities, With / Without GHG Offsets	0.1	0.8	4.7	\$60	\$13	UC
ES-11	Methane and CO <sub>2</sub> Reduction in Oil and Gas Operations, Including Fuel Use and Emissions Reduction in Venting and Flaring						UC
	Reference Case	0.1	0.5	3.9	Not estimated	Likely net benefit	UC
	High Fossil Fuel Case	0.3	0.8	6.6			UC

	Policy Option	GHG Reductions (MMtCO <sub>2</sub> e)			Net Present Value 2007–2020 (Million \$)	Cost-Effectiveness (\$/tCO <sub>2</sub> e)	Level of Support
		2012	2020	Total 2007–2020			
ES-12	GHG Reduction in Refinery Operations, Including in Future Coal-to-Liquids Refineries						UC
	Coal-to-Liquids – High Fossil Fuel Case	0	9.9	35	Not estimated	Not estimated	UC
	Petroleum Refining - Reference Case	0.02	0.24	1.5	Not estimated	Not estimated	UC
	Petroleum Refining - High Fossil Fuel Case	0.03	0.38	2.2	Not estimated	Not estimated	UC
ES-13	CO <sub>2</sub> Capture and Storage or Reuse (CCSR) in Oil & Gas Operations, Including Refineries and Coal-to-Liquids Operations	<i>Incorporated in ES-5 and 12</i>					UC
	<b>Sector Total After Adjusting for Overlaps (Among ES Options and After Demand Reductions From RCI Options)</b>						
	<b>Reference Case</b>	<b>0.4</b>	<b>4.2</b>	<b>21.9</b>	<b>\$272</b>	<b>\$17</b>	
	<b>High Fossil Fuel Case</b>	<b>0.4</b>	<b>18.7</b>	<b>79.4</b>	<b>\$870</b>	<b>\$24</b>	

UC = unanimous consent

Note: Positive numbers for net present value (NPV) and cost-effectiveness reflect net costs. Negative numbers reflect net cost savings.

\* Reflects costs (and emissions reductions) only for those items quantified.

## **Approach for the Estimation of Emissions Reductions From Electricity Policies (Production-basis vs. Consumption-Basis) for Reporting Greenhouse Gas Emission Reductions**

The Climate Change Advisory Committee (CCAC) process has discussed two accounting approaches for estimating electricity emissions: 1) the consumption-basis approach, which aims to reflect the emissions associated with electricity sources used to deliver electricity to consumers in the state and 2) the production-basis approach, which considers the emissions from Montana power plants, regardless of where the electricity is delivered. The emissions impact of Energy Supply (ES) policy options will differ depending on which approach or perspective is taken. For instance, an Environmental Portfolio Standard (EPS, ES-1) will result in increased delivery of renewable electricity and energy efficiency programs to Montana consumers, thereby directly displacing the delivery of fossil fuel-based electricity (i.e., a consumption-based impact).

The impacts of an EPS from a production-based perspective are more uncertain. An EPS might well avoid or delay the construction of new fossil-fired power plants in Montana, to the extent these plants might otherwise be sited in Montana and contracted to meet Montana demands. This option's effect on the operation of existing coal plants is less clear, since these plants could well continue to generate and sell more electricity to other states. Other options, such as Incentives for Advanced Fossil Fuel Generation and Carbon Capture and Storage (ES-5) will focus directly on reducing emissions from electricity production. In this case, the effects on electricity generation for Montana's consumption is less clear; for example, much of the lower greenhouse gas (GHG) generation could be exported.

### **Avoided Electricity Emissions**

To estimate emissions reductions from policy options that are expected to displace conventional grid-supplied electricity (i.e., those that reduce grid demand such as efficiency/conservation, renewable energy, and combined heat and power) a simple, straightforward approach is used. Through 2010, we assume that these policy options would displace generation from the then-current mix of fuel-based electricity sources. We assume that sources without significant fuel costs would not be displaced, e.g., hydro or other renewable generation. After 2010, we assume that the policy options are likely to avoid a mix of new capacity additions (plants built after 2006) and existing fossil fuel-based generation. The assumed ratio between existing and new resources has the fraction of new resources increasing from 0% in 2010 to 100% in 2020.

This approach provides a transparent way to estimate emissions reductions and to avoid double counting (by ensuring that the same megawatt hours [MWh] from a fossil fuel source is not "avoided" more than once). It also yields results that are consistent with the state-level inventory and forecast developed as part of the CCAC process. It can be considered a "first-order" approach; it does not attempt to capture a number of factors such as the distinction between peak, intermediate, and baseload generation; issues in system dispatch and control; impacts of non-dispatchable and intermittent sources such as wind and solar; or the dynamics of regional electricity markets. These relationships are complex and could mean that policy options affect generation and emissions (as well as costs) in a manner somewhat different than estimated here. Nonetheless, this approach provides reasonable first-order approximations of emissions impacts

and offers the advantages of simplicity and transparency that are important for stakeholder processes.

Note that for options that target individual facilities (e.g., ES-5, Incentives for Advanced Fossil Fuel Generation and Carbon Capture and Storage), avoided emissions are based directly on the assumed displaced resource (e.g., conventional pulverized coal [PC] plant with no capture).

### **Reference Case and High Fossil Fuel Case**

Two scenarios were developed for projections of Montana’s future GHG emissions from the electricity sector and the fossil fuel production sector. The two scenarios acknowledge the significant uncertainty of future energy production in Montana (due to economics and policy actions in Montana, other states, Canada, and internationally)—the Reference Case assumes lower growth in electricity generation and fossil fuel production than the High Fossil Fuel Case. The GHG emissions reductions associated with several of the ES options depend on which scenario is being considered. For example, the High Fossil Fuel Case assumes a greater number of coal plants will be developed than in the Reference Case—and the High Fossil Fuel Case will have a larger potential to reduce GHG emissions from carbon capture and storage than the Reference Case. For the relevant options, the GHG emission reductions and costs are reported for both the Reference Case and the High Fossil Fuel Case.

### **Option Implementation—Single Options vs. Combined Options Assessment**

The emissions reduction and cost estimates shown for each individual option presume that each option is implemented alone. Many options, particularly for electricity supply, are related in so far as they target the displacement of the same reference case resources (e.g., growth in emissions from new coal plants), or otherwise have interactive effects. Therefore, if multiple options are implemented, the results will not simply be the sum of each individual option result. For this reason, we have conducted a “combined policies” assessment to estimate total emission reductions of all recommended policies that captures the overlap among policies. For example, demand reduction (RCII options that are additional to the energy conservation/efficiency requirements of ES-1) and customer-sited renewable energy (ES-4) reduce requirements for grid electricity; as a result, fewer MWh from renewables are needed to meet the targets described in option ES-1. The effect of these interactions—lower emissions savings and costs than the sum of individual options—is reflected in the combined policy results shown in the bottom two lines of the Summary List of Recommended High Priority Mitigation Options.

## ES-1. Environmental Portfolio Standard (Renewables and Energy Efficiency)

### Policy Description

A renewable portfolio standard (RPS) is a requirement that utilities must supply a certain percentage of electricity from an eligible renewable energy source(s). For example, an RPS of 5% would mean that for every 100 kilowatt hours (kWh) a utility or a load-serving entity (LSE) supplies to end users, 5 kWh must be generated from renewable resources. An environmental portfolio standard (EPS) expands that notion to include energy efficiency as an eligible resource as well. About 20 states currently have an RPS in place (including Montana), while a handful have implemented an EPS (Washington and Nevada among them). In some cases (as in Montana), utilities can also meet their RPS or EPS requirements by purchasing certificates from eligible energy projects, typically referred to as Renewable Energy Certificates in the case of RPS policies.

### Policy Design

This policy options involves extending the existing RPS to include renewable energy requirements for 2020 and 2025 and requiring utilities to pursue cost-effective end-use energy conservation.<sup>1</sup>

**Goals:** Each investor-owned utility (IOU) and public utility (including member-owned electric cooperatives) should

- Meet 20% of its load using renewable energy resources by 2020, increasing to 25% by 2025.
- Implement a plan to obtain 100% of achievable cost-effective energy conservation by 2025.
  - By 2010, identify its achievable cost-effective energy conservation for the subsequent 10 years.
  - Update its energy efficiency assessment and plan regularly, possibly every 2 years.  
*“Energy conservation” refers to both electricity and natural gas.*

**Timing:** See above.

**Parties Involved:** IOUs, electric cooperatives, Montana Public Service Commission (PSC), state government.

**Other:** None cited.

### Implementation Mechanisms

The following aspects will need to be addressed prior to the implementation of this option:

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<sup>1</sup> End-use energy conservation comprises changes at electricity customer sites to 1) reduce energy used to provide services—such as heating, cooling, illumination, and entertainment—through increased energy efficiency of appliances and other technologies and 2) reduce demand for these services—for example, by turning off unused lights and televisions and turning down thermostats.

- Ensure that the utilities are not punished for pursuing energy efficiency. [Note: “decoupling” of utility revenues from the level of utility sales is a strategy for removing this barrier that has been proposed, and in some cases implemented, in other states.]
- Define “cost-effective” and strategies (incentives/penalties) to ensure that the energy savings are achieved.
- Adjust cost cap in existing bill.
- Consider the possibility of different standards for cost cap to apply to IOUs and co-operatives.

Given concerns about how an RPS could be enforced with respect to electric cooperatives (since cooperatives are not regulated by the PSC), further investigation regarding enforcement mechanisms for cooperatives is needed.

The CCAC noted that technologies and measures for increasing electricity production at hydroelectric and other related facilities (e.g., irrigation drops) through turbine additions and upgrades should be considered as eligible for the RPS.

### **Related Policies/Programs in Place**

Montana’s RPS, enacted in April 2005 as part of the Montana Renewable Power Production and Rural Economic Development Act (69-8-1001 through 69-8-1008, Montana Code Annotated [MCA]), requires public utilities to obtain a percentage of their retail electricity sales from eligible renewable resources according to the following schedule:

- 5% in 2008 through 2009,
- 10% in 2010 through 2014, and
- 15% in 2015 and thereafter.

Eligible renewable resources include wind, solar, geothermal, existing hydroelectric projects (10 MW or less), landfill or farm-based methane gas, wastewater-treatment gas, low-emission, nontoxic biomass, and fuel cells where hydrogen is produced with renewable fuels. Facilities must begin operation after January 1, 2005, and must be either a) located in Montana or b) located in another state and delivering electricity to Montana.

Utilities can meet the standard by entering into long-term purchase contracts for electricity bundled with renewable-energy credits (RECs), by purchasing the RECs separately, or a combination of both. The law includes cost caps that limit the additional cost utilities must pay for renewable energy and allows cost recovery from ratepayers for contracts preapproved by the Montana PSC. RECs sold through voluntary utility green power programs may not be used for compliance.

The RPS includes specific procurement requirements to stimulate rural economic development. For example, the utilities must buy a portion of the required renewable energy (electricity + credits) from community renewable-energy projects with a maximum individual nameplate capacity of 5 megawatts (MW). These include projects in which local owners have a controlling interest and that are interconnected on the utility’s side of the meter. In 2015, these projects must

provide a total of at least 75 MW of renewable-energy capacity. In addition, public utilities must enter into contracts that include a preference for Montana workers.<sup>2</sup>

Montana’s Universal System Benefits Program (USBP) also supports energy efficiency and renewable energy and is described more fully under option RCII-1.

### Type(s) of GHG Benefit(s)

**CO<sub>2</sub>:** By creating a substantial market in renewable generation and energy efficiency programs, an EPS can reduce fossil fuel use in power generation and thus reduce CO<sub>2</sub> emissions.

**Black Carbon:** To the extent that generation from coal and oil would be displaced by renewables, black carbon emissions would decrease.

### Estimated GHG Savings and Costs Per Ton

	Policy	Scenario/Element	Reductions		Cumulative Reductions 2007–2020 (MMtCO <sub>2</sub> e)*	NPV 2007–2020 (\$ Million)	Cost-Effectiveness (\$/tCO <sub>2</sub> )
			2010	2020			
ES-1	Environmental Portfolio Standard	Efficiency / Conservation (electricity only)	0.03	0.92	5.4	–\$79	–\$15
ES-1	Environmental Portfolio Standard	Renewable Energy	0.0	1.6	5.5	\$53*	\$10 <sup>†</sup>

Note: Positive numbers for Net Present Value (NPV) and Cost-Effectiveness reflect net costs. Negative numbers reflect net cost **savings**.

\* Analyzed on the basis of **consumption-based emissions**, since the EPS is focused on load.

<sup>†</sup> Costs for renewable energy are highly dependent on assumptions regarding federal Production Tax Credit (PTC). For the purposes of analysis, it is assumed that the credit will end in 2010. However, the PTC has been renewed several times and could well be renewed again. If the PTC were extended beyond 2010, this could lead to lower costs or even net cost savings.

*Results using alternative assumptions are presented in the Key Uncertainties section below.*

### Data Sources, Quantification Methods, and Key Assumptions (for quantified actions)

#### Data Sources:

- Renewable Energy Technology costs from Western Governors’ Association 2006 (WGA 2006) *Task Force Reports from the Clean and Diversified Energy Initiative*,<sup>3</sup> Energy Information Administration (EIA) Annual Energy Outlook (AEO),<sup>4</sup> National Renewable Energy Laboratory.<sup>5</sup>

<sup>2</sup> [www.dsireusa.org/library/includes/tabsrch.cfm?state=MT&type=RPS&back=regtab&Sector=S&CurrentPageID=7&EE=1&RE=1](http://www.dsireusa.org/library/includes/tabsrch.cfm?state=MT&type=RPS&back=regtab&Sector=S&CurrentPageID=7&EE=1&RE=1)

<sup>3</sup> <http://www.westgov.org/wga/initiatives/cdeac/index.htm>

<sup>4</sup> <http://www.eia.doe.gov/oiaf/aeo/assumption/index.html>

<sup>5</sup> [http://www.nrel.gov/analysis/power\\_databook/](http://www.nrel.gov/analysis/power_databook/)

- Other data sources as noted below.

**Quantification Methods:** Analysis of the EPS involves the following steps: 1) estimate the level and costs of cost-effective energy conservation (electricity and gas) that are achievable in Montana (see RCII-1); 2) identify the type of renewable generation that would most likely be used to meet the renewable energy requirements in 2010, 2015, and 2020; 3) estimate the costs associated with each type of renewable technology; 4) estimate the type, cost, and GHG emissions of the conventional generation that would be avoided by the increased energy efficiency and renewable energy (see description in the above “Approach” section on avoided costs and emissions); and 5) calculate the difference in costs and GHG emissions between the EPS scenario and the reference case.

This option will be analyzed in two stages: the first stage estimates the costs and emission reductions from energy efficiency alone (from the RCII-1 analysis), while the second stage considers the costs and reductions from the additional renewable energy generation requirements. Costs and emission reductions are calculated as incremental to the reference case, which includes energy efficiency savings expected from current and planned utility programs and the renewable energy generation to meet the existing RPS (see the “Related Policies/Programs in Place” section below).

#### **Key Assumptions:**

- **Efficiency potential and cost**—See RCII-1.
- **Renewable energy mix**—It is assumed that the renewable portion of the Montana EPS would be met with a combination of wind and biomass. For this preliminary analysis, it is assumed that the renewable mix is made up of 90% wind and 10% biomass.
- **Renewable energy costs**—The costs of the new renewable systems are based on those used in the EIA Annual Energy Outlook for 2007, except where better (e.g., updated or more local) data are available. The cost of renewable generation includes costs associated with connecting renewable technologies to the electric grid and transmitting the renewable generation to loads (see below). The cost of wind generation also includes costs associated with integrating wind into the system, as detailed below.
- **Production tax credit**—For qualifying renewable energy technologies, a federal tax credit of \$18/MWh (inflated) is assumed for the first 10 years of operation for new facilities that commence operation by the end of 2010.
- **Transmission expansion costs**—Since many renewable resources are located away from existing transmission lines, additional transmission would likely be needed. Since the precise nature of those additional costs would require calculations beyond the scope of the current analysis, we propose using an average cost of \$80/kW for all new resources, based on a recent scenario analysis by the WGA Clean and Diversified Energy Advisory Committee (CDEAC).<sup>6</sup>

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<sup>6</sup> CDEAC Transmission Report in the High Renewables case has an average incremental transmission cost of 80 \$/kW compared with the reference case, i.e., 84,641 MW incremental capacity with additional transmission expansion costs of \$6,786 million.

- **Reference technology costs**—For overall consistency, we use technology costs from EIA’s Annual Energy Outlook for 2007, as shown in Table G-1.<sup>7</sup> While prices have recently gone up significantly for wind turbines, as well as for other technologies including coal units due to tight markets and high materials prices, these estimates reflect a longer-term view. See discussion under “Key Uncertainties.”

**Table G-1. Assumptions used for biomass and wind technology parameters**

Technology	Technology Parameters						
	2010			2020			
	Total Overnight Cost (\$/kW)	Variable O&M (mills/kWh)	Fixed O&M (\$/kW)	Total Overnight Cost (\$/kW)	Variable O&M (mills/kWh)	Fixed O&M (\$/kW)	Project Life (Years)
Biomass	1,833	3.0	50	1,721	3.0	50	30
Wind	1,194	0	28	1,194	0	27	20

O&M = operation and maintenance.

All costs are expressed in year 2005 dollars and represent expectations as of late 2006.

Source: Assumptions for the Annual Energy Outlook 2007, Renewable Fuels and Electricity Supply sections.<sup>8</sup>

- **Wind integration costs**—The cost of integrating wind at various levels of wind penetration is estimated on the basis of studies by utilities in the Northwest (Avista, Idaho Power, Puget Sound Energy, and Pacificorp) as compiled for the *Northwest Wind Integration Action Plan* (March 2007).<sup>9</sup> In general, wind integration costs rise with increasing penetration of wind in the grid, as shown in Table G-2. However, these estimates are subject to considerable uncertainty (see discussion below under “Key Uncertainties”).

**Table G-2. Wind integration costs**

Wind Capacity Fraction of System Peak	Average Wind Integration Cost (\$/MWh of Wind Generation)
0%	0.0
5%	\$3
10%	\$6
20%	\$8
30%	\$12.5

- **Avoided costs**—Electricity avoided costs are provisionally based on the levelized value of long-term standard Qualifying Facilities Tariff from the Montana PSC (\$49 per MWh).<sup>10</sup>

<sup>7</sup> Electric Market Module, EIA Assumptions to the Annual Energy Outlook 2006.

<sup>8</sup> <http://www.eia.doe.gov/oiaf/aeo/assumption/index.html>

<sup>9</sup> <http://www.nwcouncil.org/energy/Wind/library/2007-1.pdf>

<sup>10</sup> Estimate derived from contract data underlying the “the long-term, standard QF [Qualifying Facilities] tariff,” “Option 1” (\$49.90 per MWh, nominal cost average of quarterly contract costs from 2007 through 2014) as set by the Montana Public Services Commission, in an order covering Docket No. D2003.7.86, Order No. 6501f 2; Docket No. D2004.6.96, Order No. 6501f; and Docket No. D2005.6.103, Order No. 6501f, dated December 19, 2006. The

- **Avoided electricity emissions**—See description in the above “Approach” section on avoided emissions.

## Key Uncertainties

**Capital costs:** Wind capital costs used for the analysis above (around \$1,200/kW) are based on the United States Department of Energy’s (US DOE’s) most recent long-term projections. In the past couple of years, wind capital costs have been higher than these levels.<sup>11</sup> Some recent utility Integrated Resource Plans (IRPs) suggest the current capital costs of a 100–200 MW facility may be as high as \$1,700/kW (not including land/site acquisition).<sup>12</sup> This higher cost appears to be due in large part to an increase in the costs of materials (e.g., steel) and to the rapid expansion of the wind industry globally.

**Avoided costs:** Significant increases in capital costs have also been witnessed in recent years for other power plant types, including coal plants. If higher than projected costs persist into the next decade for power plants that would be avoided through increased renewable electricity generation, the assumptions for avoided cost of electricity may also be too low.

**Production tax credit:** As noted, costs for renewable energy are highly dependent on assumptions regarding the federal Production Tax Credit (PTC). The PTC has been renewed several times and could well be renewed again, leading to lower costs of the RPS to Montana.

**Wind integration costs:** The market for integration services is constrained at present, and there are indications that the cost of such services will increase, at least in the near term. When NorthWestern Energy’s (NWE’s) Judith Gap project came online, the reported cost for wind integration was approximately \$7/MWh.<sup>13</sup> However, NWE has announced publicly that the entities that provided that service in the past may not provide the service in the future, and if they do, the cost will likely increase.

If costs for integration services increase significantly, and if other measures to reduce the need for such services are not undertaken, achieving the renewable energy goals set forth here could

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\$49.90 cost indicated is shown in paragraph 184 of the PSC document. Cost shown here extends the stream of nominal costs in the original NorthWestern Energy/PPL Montana (NWE/PPL) document by including values for 2015 to 2020 that increment the 2014 average value at the rate of inflation, levelize the resulting 2007 to 2020 stream, and adjust the levelized value to 2005 dollars.

<sup>11</sup> Recent utility plans in the region have used the following costs: Avista 2005 IRP—\$1,191 (100 MW), IPC 2006 IRP—\$1,610 (100 MW), NorthWestern Energy 2006 DSP—\$1,010 (100 MW), Northwest Power and Conservation Council 2007 Report (2006\$)—\$1,500 (150 MW), PacifiCorps 2004 IRP update (2005\$)—\$1,474 (50 MW), Portland General 2007 IRP (2006\$)—\$1,700 (100 MW), Puget Sound 2005 IRP (2006\$)—\$1,438 (150 MW), Seattle City Light 2006 Draft IRP (2006\$)—\$1,500.

<sup>12</sup> For example, see Standard and Poor’s Viewpoint (May 11, 2007, “Which Power Generation Technologies Will Take the Lead in Response to Carbon Controls?”) and US DOE 2007 Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2006. National Renewable Energy Laboratory.

<sup>13</sup> “NWE has reported to the Montana Public Service Commission a wind integration cost of \$6.75/MWh for the Judith Gap project for 2006. This value is yet to include the expenses for the operation of the Basin Creek gas-fired plant that are solely attributable to wind integration. The wind integration costs for Basin Creek have not been finalized for 2006. The NWE control area has a wind penetration of 8.7% and is currently purchasing all of its control area services at market-based rates.” Northwest Wind Integration Action Plan, March 2007.

come at a higher cost. For this purpose, an illustrative sensitivity analysis is shown below with a value for future integration costs at high penetration levels reaching \$20/MWh.<sup>14</sup>

### Impacts of Alternative Assumptions

In order to test the sensitivity of above uncertainties on the estimated costs and cost-effectiveness, we re-estimated the options with alternative assumptions for the key uncertainties.

Table G-3 summarizes the alternative assumptions that we tested, and the changes to the cost and cost-effectiveness results. Each alternative assumption was tested individually, but the effects of combining the alternative assumptions can be roughly estimated by summing the changes.

For example, Table G-3 indicates that if the capital cost of new wind plants is \$1,800/kW, rather than the initial assumption of \$1,194/kW, then the estimated costs of the option will *increase* by \$67 million (NPV) or \$12/MtCO<sub>2</sub>e, relative to the costs based on the initial assumptions (presented above). So with higher estimates for the capital cost of new wind, the total cost is approximately \$119 million (NPV) and the cost-effectiveness is about \$22/MtCO<sub>2</sub>e. Using the assumption that the PTC will be extended to 2015, the initial costs would *decline* by \$19 million (NPV) or \$3/MtCO<sub>2</sub>e. Assuming both the higher capital cost of wind and a 2015 extension of the PTC leads to an increased cost of \$48 million (NPV) or \$9/MtCO<sub>2</sub>e.

**Table G-3. Summary of alternative assumptions, changes to cost, and cost-effectiveness results**

			Change in Results, Relative to Initial Assumptions	
	Initial Assumptions	Alternative Assumptions	Costs (\$ millions)	Cost-Effectiveness (\$/tCO <sub>2</sub> )
Capital cost of wind	\$1,194/kW	\$1,800/kW	+\$67	+\$12
Avoided cost of electricity	\$49/MWh	\$63/MWh	-\$47	-\$9
PTC sunset	2010	2015	-\$19	-\$3
<b>Wind capacity fraction of system peak</b>	<b>Average Wind Integration Cost (\$/MWh of Wind Generation)</b>		+\$35	+\$6
0%	\$0	\$0		
5%	\$3	\$7		
10%	\$6	\$20		
20%	\$8	\$20		
30%	\$12.5	\$20		

<sup>14</sup> There was considerable discussion by TWG and CCAC members as to the choice of this specific value. Some members state that not only are current regional integration costs a fraction of this amount but there is also no reasonable likelihood that integration costs will approach this amount in the future, while one CCAC member contends that such a high cost, or even a higher cost, is indeed conceivable. Given the nature of the sensitivity analysis, the \$20/MWh was retained, with the caveat that there is no specific reference to support this exact figure and that further analysis is needed.

Sources: Initial Assumptions, see above; Alternative Assumptions, based on general ranges determined during research. Alternatives for the capital cost of wind are based on sources in footnote 12, and wind integration costs were suggested by Technical Work Group (TWG) members. Alternative for the avoided cost of electricity is based on the estimated future costs of power provided by Standard and Poor's Viewpoint (May 11, 2007 *Which Power Generation Technologies Will Take the Lead in Response to Carbon Controls?*). \$63/MWh reflects the average of the costs of pulverized coal (\$58/MWh) and natural gas combined cycle (\$68/MWh).

### **Additional Benefits and Costs**

None cited.

### **Feasibility Issues**

None cited.

### **Status of Group Approval**

Completed.

### **Level of Group Support**

Unanimous consent.

### **Barriers to Consensus**

None.

## ES-2. Renewable Energy Incentives and Barrier Removal

### Policy Description

This policy option reflects financial incentives and other efforts, such as improving the ability to integrate intermittent wind resources to encourage investment in renewable energy sources by businesses that sell power commercially (smaller-scale renewable sources are covered in ES-4).

### Policy Design

This option is designed to provide additional support to the renewable portion of the renewable and energy-efficiency portfolio standard in ES-1 by providing incentives for utilities and other potential builders/developers/owners of renewable energy supply facilities as well as local manufacturers of renewable energy technologies. The goal of this option is to increase the supply of renewable energy and reduce its cost. This option is designed to support facilities that sell power commercially (as opposed to, for example, consumer-sited facilities that sell power to the grid via net metering; the latter facilities are covered under ES-4).

This option is also designed to help overcome barriers to increased penetration of renewable resources, in particular, the ability to integrate wind resources into the Montana grid.

The policy option could include the following aspects; also note the suggestions under Implementation Measures, below:

- The state, including the PSC and Montana's representatives on the Northwest Power and Conservation Council (NWPPCC), should work with other regional actors to utilize to the greatest possible extent the region's vast hydroelectric resources for the provision of integration services necessary to accommodate significant increases in generation from wind power in Montana and regionally.
- The state should provide research and development funds and should invest in technologies, such as compressed air energy storage, that can help ameliorate issues associated with wind's variability and uncertainty. See ES-3.
- Carbon markets, whether current voluntary offsets markets or future compliance markets (allowances and/or offsets), could provide an important mechanism to promote renewable energy projects. At present, there is uncertainty regarding the shape of these markets and the best strategies for the state to pursue.

**Goals:** Renewable generation goals are same as for ES-1.

**Timing:** Implement in a time frame that best supports ES-1. Since renewable goals for ES-1 will start in 2008, incentives are needed as soon as practicable. Changes to legislation will need to wait until the end of 2009.

**Parties Involved:** PSC, NWPPCC, state government, utilities

**Other:** None cited.

## Implementation Mechanisms

The following could be included:

- Tax policies, production tax credits (federal), Public Utility Regulatory Policy Act (PURPA) requirements (Montana has mini-PURPA law).
- Montana’s HB 3 (House Bill 3) from the 2007 Special Session—the “Clean and Green Energy Bill.” Recent change in property tax specification for wind projects could be expanded to other renewable forms of generation as appropriate.
- Incentives for locating manufacturing plants in the state for renewable generation, with potential sunset provisions as industries mature in Montana.
- Incentives for technologies that support improved integration of intermittent (e.g., wind) resources, including but not limited to advanced storage technologies.
- Target incentives to community wind projects.
- Tax incentives for transmission lines that carry wind power (incentives are included in Montana HB 3; see below under “Related Policies/Programs in Place”).
- A planning process that, among other things, will evaluate potential wind power sites and associated transmission infrastructure in order to develop a priority list of transmission system upgrades that will enable development of those wind power sites.
- Develop a system that certifies and recognizes new wind project proposals that have implemented measures in project siting, construction, and operation so as to minimize impacts to wildlife, critical wildlife habitat, national and state parks, and other areas of special concern. The MDEQ should work collaboratively with stakeholders to establish the criteria for such a system in order to formalize the best management practices.

## Related Policies/Programs in Place

Related policies and programs include the following:

- **Montana HB 3 (“Clean and Green Energy Bill”)**—Gives permanent property tax rate reductions from 12% to 3% of market value for new investments in transmission lines carrying “clean” electricity and “clean” liquid and also carbon sequestration pipelines. New integrated gasification combined cycle (IGCC) (with sequestration), natural gas combined cycle (NGCC), and geothermal generation. Carbon capture equipment on older power plants goes down from 6% to 3%. New DC converter stations serving two regional power grids go from 6% to 2.25%. Property tax rate abatements (non-permanent incentives) from 3% to 1.5% are available for new investments in biodiesel, biomass, biogas, and coal gasification (includes coal-to-liquids [CTL] with sequestration, ethanol, geothermal generating, NGCC with carbon offsets, transmission lines and pipelines carrying “clean” products or CO<sub>2</sub>, carbon sequestration equipment, renewable energy manufacturing plants, and research and development equipment for clean coal or renewable energy). These breaks last for 15 years after startup, with up to an additional 4 years coverage for construction. DC converter stations serving two regional grids go from 2.25% to 1.125% for 15 years, with up to an additional 4 years during construction. Agricultural land 660 feet either side of any new

transmission lines is exempt from property tax. To receive these benefits, MDEQ must certify that the projects meet the conditions of the bill.

- **Tax incentives for renewable energy**—A variety of tax incentives are available for individuals and businesses.<sup>15</sup> The Montana Code Annotated (MCA) includes:
  - **Corporate Property Tax Reduction for New/Expanded Generating Facilities (15-24-1402 MCA)**—Montana generating plants producing 1 MW or more by means of an alternative renewable energy source are eligible for the new or expanded industry property tax reduction. If approved by the local government, the facility is taxed at 50% of its taxable value in the first 5 years after the construction permit is issued. Each year thereafter, the percentage is increased by equal percentages until the full taxable value is attained in the tenth year.
  - **Generation Facility Corporate Tax Exemption (15-6-225 MCA)**—New electricity-generating facilities built in Montana with a nameplate capacity of less than 1 MW and that use an alternative renewable energy source are exempt from property taxes for 5 years after start of operation.
- **Retail Green Power (69-8-210(4) MCA)**—NWE must offer customers an opportunity to purchase a separately marketed (and possibly differently priced) product composed of power from biomass, wind, solar, or geothermal resources.
- **Clean renewable energy bonds (HB 330)**—This recently enacted legislation enables local government bond financing of renewable energy projects.<sup>16</sup>

### Type(s) of GHG Reductions

See ES-1.

### Estimated GHG Reductions and Costs (or Cost Savings)

Not quantified.

As noted above, this option supports the achievement of the renewable energy targets articulated in ES-1. To the extent that incentives enable exceedance of these targets, there may be additional emission reductions and costs (or savings).

### Key Uncertainties

None cited.

### Additional Benefits and Costs

None cited.

### Feasibility Issues

None cited.

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<sup>15</sup> A summary can be found at: <http://deq.mt.gov/Energy/Renewable/TaxIncentRenew.asp>

<sup>16</sup> <http://data.opi.mt.gov/bills/2007/billpdf/HB0330.pdf>

**Status of Group Approval**

Completed.

**Level of Group Support**

Unanimous consent.

**Barriers to Consensus**

None.

## ES-3. Research and Development (R&D), Including R&D for Energy Storage and Advanced Fossil Fuel Technologies

### Policy Description

R&D funding can be targeted toward a particular technology or group of technologies as part of a state program with a mission to build an industry around that technology in the state and/or to set the stage for adoption of the technology for use in the state. For example, an agency can be established with a mission to help develop and deploy energy storage technologies. R&D funding can also be made available to any renewable or other advanced technology through an open bidding procedure (i.e., driven by bids received rather than by a focused strategy to develop a particular technology). Funding can also be given for demonstration projects to help commercialize technologies that have already been developed but are not yet in widespread use. Funding could be provided to increase collaboration between existing institutions for R&D on technologies.

### Policy Design

This policy could include efforts to

- Seek partners for, and aim to attract, federal R&D funding for high-altitude advanced fossil demonstration project(s) in Montana as authorized by the Energy Policy Act of 2005. Consider the FutureGen process as a potential source of lessons on how to develop and succeed at funding a demonstration project. Demonstration projects are typically located near active R&D programs.
- Establish emerging energy technology program in the Montana university system, attract federal R&D funding, grow technology expertise, issue advanced degrees, and aim for resulting multiplier benefits. Consider elements of the Big Sky Carbon Sequestration Partnership (BSCSP) as a model. Choose areas for R&D that match well with the Montana resource base.<sup>17</sup> Target carbon sequestration technologies, compressed air, and other storage technologies to increase penetration of intermittent renewable energy (including wind power) and direct carbon fuel cells.
- Create a small pool of state funding for R&D efforts. Even though overall volume would be limited, it could have important symbolic value and help leverage larger amounts of external funding. Consider such funding for the university program and/or the BSCSP.
- Seek industry participation and contributions (e.g., licensing fees) to help pay for R&D activities.

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<sup>17</sup> Montana has significant coal reserves as well as a number of promising sites for CO<sub>2</sub> storage and enhanced oil recovery. For instance, Southern Montana Electric has suggested that its proposed facility (Highwood Generating Station [HGS], Great Falls, MT) may represent an ideal location to integrate the concept of CCSR into facility design and plan of operations. HGS is very well situated in close proximity to geologic formations providing a great opportunity to test the technology of carbon capture and storage on a commercial scale that demonstrates economic feasibility.

- Make available the results of R&D and pilot programs to inform industrial development.
- Consider options to provide incentives for energy storage technologies such as batteries and compressed air storage.
- Use coal severance tax to fund research and development programs (per above) in clean energy technologies, including clean coal, sequestration, and compressed air storage, among others. (Note that the 2007 Legislature recently passed HB 715 requiring a portion of the research and commercialization expendable trust [as defined in MCA 90-3-1002] be used for clean coal R&D projects or renewable resource R&D projects.)<sup>18</sup>

**Goals:** No specific goals identified.

**Timing:** Not relevant.

**Parties Involved:** Montana university system.

**Other:** None cited.

### Implementation Mechanisms

Under development.

### Related Policies/Programs in Place

**Big Sky Carbon Sequestration Partnership**—is led by Montana State University and is one of the US DOE’s seven regional partnerships. BSCSP’s goal is to develop infrastructure to support and enable future carbon sequestration field tests and deployment in Montana, Idaho, Wyoming, Washington, and Oregon.

**Zero Emission Research and Technology Center**—is a partnership involving Montana State University, as well as US DOE laboratories and West Virginia University. ZERT is a research collaborative focused on understanding the basic science of underground (geologic) carbon dioxide storage to mitigate GHGs from fossil fuel use and to develop technologies that can ensure the safety and reliability of that storage.

**FutureGen**—is a public-private partnership to design, build, and operate the world’s first coal-fueled, near-zero emissions power plant, at a cost exceeding US\$1 billion. The commercial-scale plant will prove the technical and economic feasibility of producing low-cost electricity and hydrogen from coal while nearly eliminating emissions. Two candidate sites in Illinois and Texas are being evaluated for siting of the FutureGen project.

### Type(s) of GHG Reductions

Under development.

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<sup>18</sup> HB 715, <http://data.opi.mt.gov/bills/2007/billpdf/HB0715.pdf>

### **Estimated GHG Reductions and Costs (or Cost Savings)**

Not quantified. Given the difficulties in predicting the direct impact of R&D programs on GHG emissions, the emissions reduction resulting from this option will not be quantified, though a rough estimate of option cost is desirable.

### **Key Uncertainties**

None cited.

### **Additional Benefits and Costs**

None cited.

### **Feasibility Issues**

None cited.

### **Status of Group Approval**

Completed.

### **Level of Group Support**

Unanimous consent.

### **Barriers to Consensus**

None.

## ES-4. Incentives and Barrier Removal (Including Interconnection Rules and Net Metering Arrangements) for Combined Heat and Power (CHP) and Clean Distributed Generation (DG)

### Policy Description

This option is focused on CHP and DG located on-site at consumer facilities that do not sell power commercially. There are numerous barriers to CHP and clean DG, including inadequate information, institutional barriers, high transaction costs because of small projects, high financing costs because of lender unfamiliarity and perceived risk, split incentives between building owners and tenants, and utility-related policies like interconnection requirement, high standby rates, and exit fees. The lack of standard offer or long-term contracts, payment at avoided cost levels, and lack of recognition for emissions reduction value provided also creates obstacles. Policies to remove these barriers include improved interconnection policies, improved rates and fees policies, streamlined permitting, recognition of the emission reduction value provided by CHP and clean DG, financing packages and bonding programs, power procurement policies, and education and outreach.

### Policy Design

Key elements of design for this CHP/DG incentives and barrier removal policy include<sup>19</sup>

- Creating standardized interconnection rules for CHP and DG systems to increase investor and developer certainty and predictability and reduce transaction costs.
- Considering offering different interconnection and net metering rules for smaller (residential-size, 5–10 kW) systems, because it might be easier for cooperatives to agree on a standard for these systems than for larger systems.
- Removing barriers to the adoption of CHP and DG systems by customers of Montana utilities, including electric co-ops, while taking into account the potential impact that net metering may have on cross-subsidies between consumers.
- Increasing incentives for installing CHP and DG systems.
- Increasing incentives for the development of small distributed wind systems.
- Increasing incentives for the development of solar hot water.
- Improving or expanding the Alternative Energy Revolving Loan Program (supported by air pollution noncompliance fees<sup>20</sup>) to defray some of initial costs of CHP and DG systems.

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<sup>19</sup> Two papers on the topic of reducing barriers to CHP and DG in Montana have been prepared: *Reducing Market Barriers to Small-Scale Distributed Generation in Montana*, and *Reducing Regulatory Barriers to Small-Scale Distributed Generation in Montana*, both dated May, 2004, and prepared for the Montana Department of Environmental Quality by Thomas Yoder and Brian Gurney of the Center for Applied Economic Research Montana State University–Billings.

<sup>20</sup> Another reference to this option is *Distributed Energy Generation, Benefits, Barriers and Best Practices*, Report to the 60th Legislature Energy and Telecommunications Interim Committee, dated September 2006, prepared by

- Encouraging the development of a set of state-issued licenses for renewable energy system technicians and installers. These licenses would be separate from existing electricity and plumbing trade licenses and would be tailored to the renewable energy industry, covering, for example, DC electricity wiring and roofing skills related to installation of solar photovoltaics (PV), solar hot water, and other renewable energy systems, as well as safety concerns related to system installation. The state licensing of renewable energy technicians/installers will increase consumer confidence in renewable energy contractors.
- Considering clean CHP as a net-metering eligible resource.
- Considering establishing a DG effort similar to the establishment of the Rural Electrification Administration in the 1930s that was able to electrify vast rural sections of America in a very short time period, using grants, loans, and the initiation of green co-ops to overcome many of the road blocks to DG implementation. Because of net metering, these co-ops would only have to be involved with the purchase, installation, and maintenance of the DG systems.

**Goals:** Goals used to estimate potential benefits are indicated under “Key Assumptions” below (470 MW of CHP, 4.5 MW of solar PV, and 30 MW of small wind by 2020).

**Timing:** As indicated below.

**Parties Involved:** State government and regulators, electric utilities, and renewable energy and CHP industry.

**Other:** None cited.

### Implementation Mechanisms

As indicated in the policy design above.

### Related Policies/Programs in Place

#### Montana Financial Incentives

- **Alternative Energy Investment Corporate Tax Credit (15-32-401 MCA)**—Commercial and net metering alternative energy investments of \$5,000 or more are eligible for a tax credit of up to 35% against individual or corporate tax on income generated by the investment.
- **Residential Alternative Energy System Tax Credit (15-32-201 MCA)**—Residential taxpayers who install an energy system using a recognized non-fossil form of energy on their home after December 31, 2001, are eligible for a tax credit equal to the amount of the cost of the system and installation of the system, not to exceed \$500. The tax credit may be carried over for the next 4 taxable years.
- **Residential Geothermal Systems Credit (15-32-115 MCA)**—Resident Montana taxpayers who install a geothermal heating or cooling system in their principal dwelling can claim a tax credit based on installation costs, not to exceed \$1,500.

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Casey A. Barrs, available at [http://leg.mt.gov/content/committees/interim/2005\\_2006/energy\\_telecom/staff\\_reports/DEG\\_consolidated\\_8-21-06%20\(2\).pdf](http://leg.mt.gov/content/committees/interim/2005_2006/energy_telecom/staff_reports/DEG_consolidated_8-21-06%20(2).pdf)

- **Bonneville Environmental Foundation–Renewable Energy Grant**—Using revenues generated from the sales of Green Tags, BEF, a not-for-profit organization, accepts proposals for funding renewable energy projects located in the Pacific Northwest (Oregon, Washington, Idaho, and Montana). Any private person, organization, or local or tribal government located in the Pacific Northwest may participate. Projects that generate electricity are preferred. Acceptable projects include solar PV, solar thermal electric, wind, hydro, biomass and animal waste-to-energy.
- **BEF–Solar 4R Schools**—This program began in 2002 to install small-scale solar energy systems at schools interested in increasing the visibility of renewable energy. BEF will generally completely fund or supply 1.1 kW system installations, fund up to 33% of other larger renewable energy projects, and provide curriculum modules developed for schools. The school agrees to own and maintain the solar energy system, provide access to the system, and implement an educational outreach strategy.
- **Renewable Energy Systems Exemption (15-6-224 and 15-32-102 MCA)**—Montana’s property tax exemption for recognized non-fossil forms of energy generation or low emission wood or biomass combustion devices may be claimed for 10 years after installation of the property. The exemption is allowed for single-family residential dwellings up to \$20,000 in value and for multifamily residential dwellings or a nonresidential structure up to \$100,000 in value.
- **Alternative Energy Revolving Loan Program (75-25-101 MCA)**—Provides loans to individuals, small businesses, local government agencies, units of the university system, and nonprofit organizations to install alternative energy systems that generate energy for their own use. The program is funded by air quality penalties collected by the MDEQ. In 2005, SB 50 (Senate Bill 50) amended the loan program, increasing maximum loan amount to \$40,000 (subject to available funds) and extending the repayment period to 10 years. Interest rates are set annually and are fixed for the term of the loan. The rate for 2006 is 5.0%.
- **Universal System Benefits Programs (69-8-402 MCA)**—All distribution utilities and cooperatives must collect a Universal System Benefits Charge (USBC), which is used for renewable energy programs, as well as low-income assistance and weatherization, energy efficiency, and R&D programs. Beginning January 1, 1999, 2.4% of each utility’s annual retail sales revenue in Montana for the calendar year ending December 31, 1995, was established as the initial funding level for universal system benefits programs. The USBC will remain in effect until December 31, 2009. Utilities, cooperatives, and large customers can self-direct their funds to approved internal programs.

### **Montana Rules, Regulations, and Policies**

- **Net metering (69-8-601 et seq. MCA)**—Net metering is an arrangement that allows surplus energy generated by the customer’s renewable energy system to go back to the utility electric system. The customer receives “credit” at retail rates for the electricity put back up to the amount of power the customer actually consumes at his/her location. Only NWE is required by legislation to offer net metering. Montana–Dakota Utilities and the rural electric cooperatives are voluntarily offering net metering. Terms of the offers vary by utility and can differ from these legislative requirements.

- **Interconnection Standards (69-8-604 MCA)**—Montana’s net metering legislation, enacted in 1999, requires interconnected facilities to comply with all national safety, equipment and power-quality standards. NWE has published a standard interconnection agreement for net-metered facilities; the agreement includes language on the technical requirements for interconnecting. Technical language mirrors the state law requirements with respect to national standards but also requires a manual, lockable, external disconnect switch. NWE does not require system owners to purchase additional liability insurance, but encourages system owners to confirm with their insurance provider the limits of coverage applicable to interconnected systems.
- **Electric Cooperatives–Net Metering**—The Montana Electric Cooperatives’ Association (MECA) developed and adopted a model Interconnection of Small Customer Generation Facilities policy in 2001. The model policy includes guidelines for net metering, which have been adopted in whole or part by most of the 26 electric cooperatives in Montana.

### Type(s) of GHG Benefit(s)

**CO<sub>2</sub>:** By providing a financial incentive for renewable generation, more renewable facilities would be installed and more electricity from renewables would be generated. This very-low-carbon generation would displace generation from conventional fossil fuel generation leading to CO<sub>2</sub> reductions.

**Black Carbon:** To the extent that generation from coal would be displaced by renewables, black carbon emissions would decrease.

### Estimated GHG Savings and Costs Per Ton

	Policy	Scenario	Reductions		Cumulative Reductions 2007–2020 (MMtCO <sub>2</sub> e)*	NPV 2007–2020 (\$ millions)	Cost-Effectiveness (\$/tCO <sub>2</sub> )
			2010	2020			
ES-4	Renewable DG†	4.5 MW PV by 2020, 1% of homes with solar hot water by 2015, 30 MW of small wind by 2020	0.03	0.10	0.8	\$16	\$21
ES-4	CHP	CHP potential of 470 MW	0.17	0.7	5.0	\$81	\$16
ES-4	Combined DG & CHP		0.20	0.8	5.8	\$97	\$17

\* Analyzed on the basis of **consumption-based emissions**, since this option reduces load and does not directly affect decisions about new capacity additions in Montana.

† Results are highly dependent on assumptions for small wind, which have large uncertainty.

### Data Sources, Quantification Methods, and Key Assumptions (for quantified actions)

#### A. Renewable Distributed Generation (customer-sited renewable energy)

**Data Sources:** WGA’s Clean and Diversified Energy Initiative; EIA Annual Energy Outlook 2007 assumptions; Energy Trust of Oregon, a Comparative Analysis of Community Wind Power Development Options in Oregon.

**Quantification Methods:** Starting with the goals for each technology (see below), assumptions regarding the annual penetration of new distributed systems are generated. Estimates of cost and performance for different kinds of renewable systems and costs/emissions of avoided electricity are then used to estimate the overall net GHG emissions reduction and net cost of the policy.

**Key Assumptions:**

- **Goals/Potential:**

Goal for rooftop solar (PV) systems is Montana’s share of Million Solar Roofs initiative—1,500 systems by 2020, each system about 3 kW, so 4.5 MW by 2020.<sup>21</sup>

Goal for small wind is 30 MW by 2020.

Goal for solar hot water is to have systems installed in 1% of new homes by 2015, based on WGA’s estimate of an achievable goal of 500,000 systems installed by 2015 for the entire region. The Montana fraction was estimated using the same fraction as that used for WGA estimates of solar PV by state (accounting for electricity use, solar insolation [the amount of sunlight/solar radiation], and population growth).

- **Technology costs:** From WGA 2006 Task Force Reports from the Clean and Diversified Energy Initiative,<sup>22</sup> EIA,<sup>23</sup> and Energy Trust of Oregon (Table G-4).<sup>24</sup>

**Table G-4. Costs for solar PV, solar hot water, and wind technologies**

Technology	Capital Cost (\$/kW)	Capacity Factor	Project Life (Years)	Source/Notes
Solar PV	Residential: \$5,500 (2010) \$4,010 (2020)  Commercial \$2,680 (2010) \$2,140 (2020)	20%	20	WGA Clean and Diversified Energy Initiative report on Solar PV
Solar hot water	\$2,800 (2010) \$2,200 (2020)	75%	20	EIA Annual Energy Outlook assumptions
Wind	\$2,388 (2010) \$1,094 (2020)	35%	20	Energy Trust of Oregon for 2020, 2010 rough estimate

- **Avoided costs:** See ES-1 above, also accounting for avoided transmission and distribution costs.

<sup>21</sup> Personal communication, Pat Judge MEIC and Chris Daum, Oasis Montana, February 2007.

<sup>22</sup> <http://www.westgov.org/wga/initiatives/cdeac/index.htm>

<sup>23</sup> <http://www.eia.doe.gov/oiaf/aeo/assumption/index.html>

<sup>24</sup> A Comparative Analysis of Community Wind Power Development Options in Oregon <http://www.oregon.gov/ENERGY/RENEW/Wind/docs/CommunityWindReportLBLforETO.pdf>

- **Avoided electricity emissions:** See description in the above “Approach” section on avoided emissions.

## B. Combined Heat and Power

### Data Sources:

- The *Combined Heat and Power White Paper*, January 2006, to the Clean and Diversified Energy Initiative (CDEI) of the WGA; and the *2003 Commercial Buildings Energy Consumption Survey Detailed Tables*, published by the US DOE’s EIA.

**Quantification Methods:** Starting with an estimate for Montana’s share of CHP potential in the West, as provided in the “CHP White Paper” referenced above, assumptions regarding the penetration of and fuel shares for new CHP systems and estimates of future capacity of CHP developed under the policy are generated. Estimates of CHP cost and performance for different kinds of systems are then used to estimate the overall net GHG emissions reduction and net cost of the policy.

**Key Assumptions:** Key assumptions are the CHP potential in Montana, the analysis based on a potential of 470 MW (per the WGA/CDEI source above);<sup>25</sup> this potential grows with commercial and industrial loads, and the potential can be realized at a rate of about 2%–3% of total potential per year (Table G-5). Gas-fired systems are assumed to dominate new CHP, but some biomass- and coal-fired–capacity is also assumed. Systems are assumed to operate an average of 5,000 hours per year (at full capacity), and 90% of co-generated heat is assumed to be usable (and displaces heat from purchased fuels).

**Table G-5. Technology characteristics of new CHP equipment**

Technology	Capital Cost (\$/kW)		Fraction of New CHP Capacity	
	2010	2020	2010	2020
Natural gas	\$1260	\$1180	90%	85%
Biomass	\$1510	\$1430	5%	12%
Coal	\$1260	\$1180	5%	3%

Source: EIA *Assumptions for Annual Energy Outlook 2007 (Industrial Sector)* for capital costs—based on a 3MW gas turbine with additional costs assumed for biomass, fraction of capacity by fuel type are assumptions for this policy.

- **Avoided costs:** See ES-1 above.
- **Avoided electricity emissions:** See description in the above “Approach” section on avoided emissions.

### Key Uncertainties

None cited.

<sup>25</sup> An alternate estimate of CHP potential is 1,092 MW from a 2004 analysis by the Western Resource Advocates, *A Balanced Energy Plan for the Interior West* at: <http://www.westernresourceadvocates.org/energy/clenergy.php>

**Additional Benefits and Costs**

None cited.

**Feasibility Issues**

None cited.

**Status of Group Approval**

Completed.

**Level of Group Support**

Unanimous consent.

**Barriers to Consensus**

None.

## ES-5. Incentives for Advanced Fossil Fuel Generation and Carbon Capture and Storage or Reuse (CCSR), Including Combined Hydrogen and Electricity Production with Geological Carbon Sequestration

### Policy Description

Advanced fossil technologies produce fewer CO<sub>2</sub> emissions per kWh as a result of more efficient generating technologies (supercritical coal, IGCC) and/or CCSR. Differing technologies may apply either before or after fuel combustion.

Policies for advanced fossil technologies can include regulations or incentives to promote advanced technologies for new or existing coal or natural gas plants. A technology regulation might require that new coal plants achieve a certain CO<sub>2</sub> emission rate. Incentives may be in the form of direct subsidies, assistance in securing financing and/or off-take agreements, or a guaranteed cost recovery for prudently incurred utility investments.

### Policy Design

This policy option would

- Direct MDEQ or direct the state to enter into a regional collaborative effort to develop standards and protocols for CCSR.
- Strengthen the Major Facility Siting Act to enable eminent domain for pipelines to transport CO<sub>2</sub> and protect landowners with appropriate siting requirements.
- Address liability issues associated with carbon capture and storage.
- Create a requirement that all fossil-fuel-fired electric generation facilities must meet a technology/fuel-neutral emissions level expressed in tCO<sub>2</sub>/MWh as needed to achieve this level. Facilities must file a plan with the MDEQ, Air Permitting Section, that details the facility's commitment to capture and/or sequester (by geological or terrestrial means) carbon dioxide emissions, as an attribute of operating plans and permits.
  - CCAC recommends that MDEQ petition the Montana Board of Environmental Review (BER) for such a rule with specific suggested language.
  - CCAC also suggests the legislature approve supporting legislation. The CCAC recommends an emissions goal of 0.5 tCO<sub>2</sub>/MWh (or 1,100 lbs/MWh), decreasing commensurate with best available control technology.

**Goals:** None yet specified. Quantification of this option will investigate the potential emissions and cost consequences of implementing CCSR for new facilities anticipated under the GHG forecast (and the high fossil fuel scenario.)

**Timing:** To be determined.

**Parties Involved:** Electrical generating facilities, Montana PSC, MDEQ, BER.

**Other:** None cited.

### Implementation Mechanisms

**Carbon Sequestration:** Rule changes would have to be made by the MDEQ to the Major Facility Siting Act regarding sequestration pipelines and then brought before the BER for approval.

**Technology Emissions Level Requirement:** A rule would have to be established by the BER that requires all fossil-fuel-fired electric generation facilities to meet a technology/fuel-neutral emissions level expressed in tCO<sub>2</sub>/MWh. Upon finalization of such a rule, the MDEQ would review and approve applications filed by generation facilities that detail the facility’s analysis of its plan to meet the applicable standard. This would become a new integral part of the air permitting process for generation facilities. After issuance of permits with technology/fuel-neutral emission limits for CO<sub>2</sub>, MDEQ would verify compliance with the applicable standards.

### Related Policies/Programs in Place

**Montana HB 3 (“Clean and Green Energy Bill”):** Gives permanent property tax rate reductions from 12% to 3% of market value for new investments in transmission lines carrying “clean” electricity and “clean” liquid, along with carbon sequestration pipelines. New IGCC (with sequestration), NGCC, geothermal generation, carbon capture equipment on older power plants go down from 6% to 3%. New DC converter stations serving two regional power grids go from 6% to 2.25%. Property tax rate abatements (non-permanent incentives) from 3% to 1.5% are available for new investments in biodiesel, biomass, biogas, coal gasification (includes CTL) with sequestration, ethanol, geothermal generating, NGCC with carbon offsets, transmission lines and pipelines carrying “clean” products or CO<sub>2</sub>, carbon sequestration equipment, renewable energy manufacturing plants, and R&D equipment for clean coal or renewable energy. These breaks last for 15 years after startup, with up to an additional 4 years coverage for construction. DC converter stations serving two regional grids go from 2.25% to 1.125% for 15 years, with up to an additional 4 years during construction. Agricultural land 660 feet on either side of any new transmission line is exempt from property tax. To receive these benefits, MDEQ must certify the projects meet the conditions of the bill. Such certification would likely follow a process similar to the Tax Certification/Classification of Air Pollution Control Equipment that is currently administered by the MDEQ.

**Air Permits:** MDEQ receives applications, reviews impacts, and issues permits for emissions.

### Type(s) of GHG Benefit(s)

**CO<sub>2</sub>:** Reductions in CO<sub>2</sub> emissions can be achieved by encouraging more efficient generation and/or through carbon capture and storage.

**Black Carbon:** Similarly, all other air emissions could decrease, especially with coal gasification and/or carbon capture and storage, since combustion is avoided.

## Estimated GHG Savings and Costs Per Ton

	Policy	Scenario	Reductions		Cumulative Reductions 2007–2020 (MMtCO <sub>2</sub> e)*	NPV 2007–2020 (\$ Million)	Cost-Effectiveness (\$/tCO <sub>2</sub> )
			2010	2020			
ES-5	Advanced Coal/Fossil Technologies	Reference Case	0	1.0	4.5	\$135	\$30
ES-5	Advanced Coal/Fossil Technologies	High Fossil Fuel Case	0	5.2	24.4	\$733	\$30

\* Analyzed on the basis of **production-based emissions**.

*Reuse of CO<sub>2</sub> in enhanced oil recovery could lower costs substantially; however, one would also need to consider whether the same level of sequestration would occur due to potential leakage.*

## Data Sources, Quantification Methods, and Key Assumptions (for quantified actions)

Given the uncertainty regarding this policy option—and with respect to the ultimate costs and performance of CCSR technologies—only an illustrative quantification is possible. To this end, we compiled estimates of the possible costs and emissions savings associated with introducing CCSR technologies under the reference case and high fossil case scenarios, under the assumptions noted below. It is important to emphasize that achieving the illustrative outcomes reported here would likely require a number of policy and other actions well beyond the items currently listed in the policy design described above, as well as confidence that these technologies will perform as projected.

### Data Sources:

- The recently released Massachusetts Institute of Technology (MIT) report, “The Future of Coal” (2007),<sup>26</sup> which provides estimates of costs and emissions savings from various coal technologies with and without carbon capture and storage.
- The Intergovernmental Panel on Climate Change (IPCC) Special Report on Carbon Dioxide Capture and Storage (2006),<sup>27</sup> which provides other estimates, including rough estimates of the costs of CO<sub>2</sub> transport and storage.
- United States Environmental Protection Agency (US EPA) report, “Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies” (July 2006), which contains cost and performance estimates for various coal plant types and CO<sub>2</sub> capture, accounting also for high elevation issues with IGCC as might be encountered in Montana.
- Advanced Coal Task force report and spreadsheets from WGA 2006 *Clean and Diversified Energy Initiative*.<sup>28</sup>

<sup>26</sup> <http://web.mit.edu/coal/>

<sup>27</sup> <http://www.ipcc.ch/activity/srcs/index.htm>

<sup>28</sup> <http://www.westgov.org/wga/initiatives/cdeac/index.htm>

**Quantification Methods:** See additional information at the end of this section.

**Key Assumptions:**

- **Projected levels of new coal builds.** This amounts to about 400 MW in the reference case and 2,000 MW in the high fossil fuel case (see the inventory/forecast documentation referenced in Appendix D). Due to the added energy requirements of capture (and transport and storage) technologies of 14%–40% (depending on CCS technologies), the plants would need to be sized larger by roughly this amount. These added energy requirements are factored into the cost and emission savings estimates provided here.
- An implicit assumption is that support, incentives, and/or requirements for advanced coal and CCSR will not affect the overall amount of coal builds in Montana.
- **Timing and extent of carbon capture and storage.**
  - All new coal generation from [2010] onwards would be provided by CCSR-capable technologies instead of conventional coal plants.
  - CCSR would commence at new coal plants as of 2015, and the fraction of CO<sub>2</sub> captured would be as noted in the goals above. This corresponds to the fraction of capture analyzed in major analyses (IPCC, MIT, above); however, it is quite possible that lower fraction of capture may be pursued.
- **Costs and operational characteristics of advanced coal and capture technologies, including CO<sub>2</sub> transport and storage.** Ranges of cost and performance estimates for the major elements of CCSR systems, as drawn from MIT, IPCC, and EPA studies, are shown in Table G-6. Cost estimates are shown in terms of overall costs per tonne of CO<sub>2</sub> avoided, and depend on technology and technical assumptions (see table notes for Table G-6). Given the range, for the illustrative analysis, we use the most recent estimates from the MIT study, which found that “for new plant construction, a CO<sub>2</sub> emission price of approximately \$30/tonne would make CCS cost competitive with coal combustion and conversion systems without CCS. This would be sufficient to offset the cost of CO<sub>2</sub> capture and pressurization (about \$25/tonne) and CO<sub>2</sub> transportation and storage (about \$5/tonne). This estimate of CCS cost is uncertain; it might be larger and with new technology, perhaps smaller.” (p. xi, MIT, 2007)
- Detailed bottom-up technology cost estimates for Montana-specific conditions and factors would be ideal, but do not appear warranted for this process, given the overall uncertainties regarding future costs and performance of these technologies. Montana-specific factors that might influence cost and performance include coal quality and high elevation (which could decrease the performance of IGCC units), and the location of suitable storage site or enhanced oil or coal bed methane recovery sites.

**Table G-6. Summary of carbon capture storage and reuse cost estimates for new coal plants (all costs in \$/tCO<sub>2</sub> avoided, transported, or stored)**

	MIT, 2007	IPCC, 2006*	EPA, 2006
New PC or FBC coal plant with CCS	\$39–\$48 <sup>†‡</sup>	\$30–\$70 \$10–\$40 (with EOR)	\$35 (supercritical)
New IGCC plant with CCS (avoided cost)	\$19–\$24 <sup>†</sup>	\$20–\$70 \$0–\$40 (with EOR)	\$24
Cost of transport and storage	\$5 inclusive	\$1–\$8 transport \$0.5–\$8 net injected storage (excluding potential revenues from EOR or ECBM) \$0.1–\$0.3 injected for monitoring and verification	\$0.5–\$2 transport (220 miles)
Overall reduction in CO <sub>2</sub> per kWh produced		81%–88% PC 81%–91% IGCC	

PC = pulverized coal; FBC = fluidized bed combustion; CCS = combined capture and storage; EOR = enhanced oil recovery; IGCC = integrated gasification combined cycle.

All estimates are for CO<sub>2</sub> avoided and assumed 90% capture.

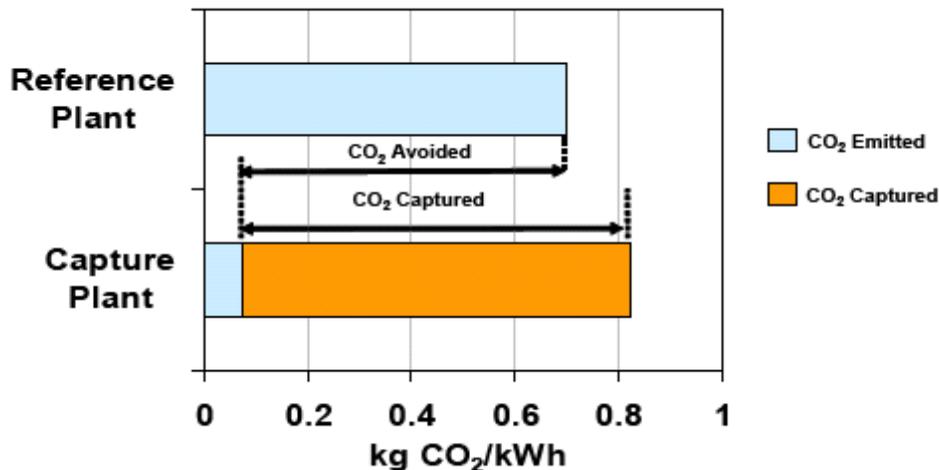
\* Reference plant is a PC coal plant

<sup>†</sup> Low end of range generally reflects avoided plant with the same technology; high end of range generally reflects avoidance of a supercritical (high efficiency) PC plant.

<sup>‡</sup> Range reflects several plant types such as subcritical, supercritical, fluidized bed.

Another approach to consider is the avoided cost of capturing CO<sub>2</sub>, as illustrated in Figure G-1.

**Figure G-1. Illustration of avoided cost for CO<sub>2</sub> capture.**



Source: USEPA, 2006

All costs shown above reflect “avoided costs” not “capture costs,” i.e., costs are spread over the amount of CO<sub>2</sub> avoided, which is less than the amount of CO<sub>2</sub> captured.

### **Key Uncertainties**

Discussed in the above section.

### **Additional Benefits and Costs**

As with ES-12, the CCAC recognizes the potential impact of increased oil and gas production through the use of CO<sub>2</sub> from carbon capture for enhanced oil or coal bed methane recovery.

### **Feasibility Issues**

Timeframe in which advanced coal technologies become economically viable.

### **Status of Group Approval**

Completed.

### **Level of Group Support**

Unanimous consent.

### **Barriers to Consensus**

None.

## ES-6. Efficiency Improvements and Repowering of Existing Plants

### Policy Description

Efficiency improvements refer to increasing generation efficiency at power stations through incremental improvements at existing plants (e.g., more efficient boilers and turbines, improved control systems, or combined cycle technology). Repowering existing power plants refers to switching to lower or zero emitting fuels at existing plants, or for new capacity additions. This includes co-firing biomass as coal plant fuel or the use of natural gas in place of coal or oil. Policies to encourage efficiency improvements and repowering of existing plants could include incentives or regulations as described in ES-5 above, with adjustments for financing opportunities and emission rates of existing plants.

### Policy Design

The state should investigate and implement policies that encourage the reduction of GHG emissions per MWh produced, or in the case of renewable energy facilities, encourage an increase of output at existing facilities. The co-firing of biomass at coal and other fossil fuel plants, and advanced technologies, such as oxyfuel combustion, deserve particular attention.

**Goals:** Under development.

**Timing:** Under development.

**Parties Involved:** Under development.

**Other:** None cited.

### Implementation Mechanisms

None cited.

### Related Policies/Programs in Place

None identified.

### Type(s) of GHG Reductions

CO<sub>2</sub> and black carbon emissions associated with coal energy generation would decrease to the extent that those facilities become more efficient (and therefore need less input fuel to meet electricity demand).

### Estimated GHG Reductions and Costs (or Cost Savings)

Not quantified.

### Key Uncertainties

None cited.

**Additional Benefits and Costs**

None cited.

**Feasibility Issues**

None cited.

**Status of Group Approval**

Completed.

**Level of Group Support**

Unanimous consent.

**Barriers to Consensus**

None.

## **ES-7. Demand-Side Management**

This option was investigated by the RCII TWG.

## ES-8/9. Market-Based Mechanisms to Establish a Price Signal for GHG Emissions (GHG Cap-and-Trade or Tax)

### Policy Description

Establishing a price on GHG emissions (or carbon dioxide specifically) is considered essential in order to reduce GHG emissions. Presently the cost of emitting carbon dioxide into the atmosphere is free. With a cost attached to carbon emissions, emitters would have a strong incentive to modify their practices, and economic inefficiencies inherent in the present system would be addressed, leading to a reduction in GHG emissions.

There are two principal ways to place a value on carbon: a carbon tax or a cap-and-trade system.

A GHG tax, or specifically a tax on CO<sub>2</sub>, would be a tax on each ton of CO<sub>2</sub> (equivalents) emitted from an emissions source covered by the tax. A CO<sub>2</sub> tax could be imposed upstream based on carbon content of fuels (e.g., fossil fuel suppliers) or at the point of combustion and emission (e.g., typically large point sources such as power plants or refineries). Taxed entities would pass some or all of the cost on to consumers, change production to lower emissions, or a combination of the two. As the suppliers respond to the tax, consumers would see the implicit cost of CO<sub>2</sub> emissions in products and services and would adjust their behavior to purchase substitute goods and services that result in lower CO<sub>2</sub> emissions. CO<sub>2</sub> tax revenue could be used in a variety of ways such as payroll or income tax reductions or for policies and programs to assist in decreasing CO<sub>2</sub> emissions. CO<sub>2</sub> tax revenue could also be directed to increasing the competitiveness of industries or assisting communities most affected by the tax.

A cap-and-trade system uses a more indirect approach to placing a value on carbon. It is a market mechanism in which GHG emissions are limited or capped at a specified level, and those participating in the system can trade allowances (an allowance is a permit to emit one ton of CO<sub>2</sub>). By allowing 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, overall costs of compliance are lower than they would be otherwise.

For every ton of CO<sub>2</sub> released, an emitter must hold an allowance. The total number of allowances issued or allocated is the cap. The government can assign a certain amount of allowances to emission sources, hold back allowances for distribution to developing sources (e.g., new entrants), auction some or all of them, or provide a combination of these options. Participants can range from a small group within a single sector to the entire economy. The compliance obligation can be imposed upstream (at the fuel extraction or import level) or downstream at points of fuel consumption.

Among the important considerations with respect to a cap-and-trade program are the sources and sectors to which it would apply; the level and timing of the cap; how the level of the cap may change over time, if at all (e.g., through a specifically declining cap); how allowances would be distributed (e.g., whether load-based or generation-based); how new market entrants are

accommodated; and how “leakage”<sup>29</sup> is addressed. Further emissions reductions are achieved by decreasing the number of allowances over time. Other questions include what if any offsets would be allowed, over what region the program would be implemented (e.g., nationally or regionally), and whether compliance with the cap could be achieved given “leakage” from nonparticipating states and coal-fired generation located on tribal lands not subject to the cap. Thus, the effectiveness of a cap-and-trade system is correlated with the extent and scope of its coverage. Further issues to consider include which GHGs are covered; whether there is linkage to other trading programs; banking and borrowing of allowances; credit for early reductions; what, if any, incentive opportunities may be included; use of revenue accrued from permit auctions, if any; and provisions for encouraging energy efficiency.

Both of these mechanisms would be most effectively implemented on a national level. This is largely because the nation’s carbon footprint is so large, cutting across virtually all sectors of our economy; accordingly a national strategy and program for reducing GHG emissions is desirable. However, both a carbon tax and a cap-and-trade program could be implemented on a state or regional basis. It is likely that if a carbon tax were to be instituted at some other level than federal, it would be by an individual state, owing to the political difficulties of having more than one state impose an identical tax. Conversely, if a cap-and-trade program is contemplated, it does not make sense for most states to go it alone but, rather, to join in a multistate effort in order to take advantage of a larger market for conducting transactions.

Most economists prefer the vehicle of a tax because it is a more direct way to influence behavior, sends a clearer price signal, and relies on existing markets rather than on the establishment of an entirely new market, is easier to adjust if reductions achieved differ from projected results, and would arguably lead to a more efficient outcome in that economic decisions would be more closely matched to product value.

However, many observers believe that a carbon tax stands little chance of being enacted, either nationally or on a statewide basis. Taxes are often controversial and difficult to enact.

A cap-and-trade system, as the above discussion suggests, will also be difficult to implement, but the successful sulfur dioxide program under the Clean Air Act, which cost-effectively led to significant reductions of that pollutant on a nationwide basis, serves as a positive precedent. Allowing participants to sell allowances creates proponents for such a system, namely those who think they will benefit from it.

There is one regional GHG cap-and-trade system in the United States in the process of being implemented and another under likely development. The cap-and-trade system designed by the Northeast States’ Regional Greenhouse Gas Initiative (RGGI)—an effort by the states of Connecticut, Delaware, Maine, Maryland, New Hampshire, New Jersey, New York, Rhode Island, and Vermont—will begin operation in 2009 and is limited to power plant emissions.<sup>30</sup> The Western Climate Initiative (WCI) is an effort by 6 states (Washington, California, Oregon, Arizona, New Mexico, and Utah) and two Canadian provinces (British Columbia and Manitoba),

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<sup>29</sup> Emissions “leakage” can occur, for instance, if production is shifted to higher-emitting sources not included within the cap.

<sup>30</sup> <http://www.rggi.org/>

that aims to design “a regional market-based multi-sector mechanism, such as a load-based cap-and-trade program, to achieve the regional GHG reduction goal.”<sup>31</sup> In contrast to RGGI, the WCI is economy-wide. While the exact mechanism to be used has not yet been decided, it is widely believed that some form of a cap-and-trade program will be chosen.

Some CCAC members believe that a national carbon tax is the preferred strategy. Other CCAC members believe that a national cap-and-trade system is not only preferred but stands a more realistic chance of being adopted than a national carbon tax. Collectively, however, the CCAC determines not to take a position on these competing mechanisms because we recognize that our ability to influence national policy is limited. The CCAC underscores that one of these mechanisms, or some other mechanism, needs to be adopted by the federal government in the near future if the nation is to achieve significant reductions in GHG emissions.

That does not mean that Montana is powerless to affect the direction of these policies, however. The establishment of the WCI puts significant pressure on the federal government to act. Moreover, since it seems likely that the WCI will employ a cap-and-trade system, the effort creates additional momentum for the creation of a national cap-and-trade system. The more states that join WCI, the greater the pressure and the more momentum generated. In addition, and very important to our thinking, Montana’s influence on the design of a national cap-and-trade system will be relatively limited, but in the context of a western regional effort, Montana’s ability to influence matters will be comparatively great. Accordingly, the CCAC recommends that Montana seek to join the WCI.

## Policy Design

The state should investigate and advocate for a national GHG cap-and-trade or tax system.

The state should participate fully in the Western Regional Climate Action Initiative, which will consider development of a regional market-based mechanism.

**Goals:** Not specified.

**Timing:** Not specified.

**Parties Involved:** Other Western states.

**Other:** None cited.

## Implementation Mechanisms

Among the important considerations with respect to a cap-and-trade program are the sources and sectors to which it would apply, the level and timing of the cap, how allowances would be distributed (e.g., whether load-based or generation-based), how new market entrants would be accommodated, and how leakage would be addressed. Other factors include how allowances would be reduced over time; what if any offsets would be allowed; over what region the program would be implemented (e.g., nationally or regionally); and whether compliance with the cap could be achieved, given “leakage” from nonparticipating states and coal-fired generation

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<sup>31</sup> The State of Utah and the Provinces of British Columbia and Manitoba joined after the initiative was announced.

located on tribal lands not subject to the state-imposed cap. Further issues to consider include which GHGs are covered; whether there is linkage to other trading programs; banking and borrowing; early reduction credit; what, if any, incentive opportunities may be included; use of any revenue accrued from permit auctions; and provisions for encouraging energy efficiency.

The principal example of an existing implementation of a GHG cap-and-trade system in the United States today is the Northeast States' RGGI: <http://www.rggi.org/>.

In February 2007, Washington, California, Oregon, Arizona, and New Mexico signed the Western Regional Climate Action Initiative. This became the above mentioned Western Climate Initiative ([www.wetrnclimateinitiative.org](http://www.wetrnclimateinitiative.org)). It WCI partners agreement states:

“This collaboration shall include, but is not limited to:

- Setting an overall regional goal, within six months of the effective date of this initiative, to reduce emissions from our states collectively, consistent with state-by-state goals;
- Developing, within eighteen months of the effective date of this agreement, a design for a regional market-based multi-sector mechanism, such as a load-based cap and trade program, to achieve the regional GHG reduction goal; and
- Participating in a multi-state GHG registry to enable tracking, management, and crediting for entities that reduce GHG emissions, consistent with state GHG reporting mechanisms and requirements.”<sup>32</sup>

Various carbon tax policies have been implemented in Europe, Australia, and Japan. Several have been proposed in the U.S., but only the City of Boulder, CO has implemented a carbon tax. In some cases carbon taxes are used to offset other taxes such as income or wage/ payroll taxes, in others they are used to support public transportation, high efficiency vehicles, and energy alternatives. Attachment A at the end of this document provides brief information on the approaches of existing programs.

### **Related Policies/Programs in Place**

None identified.

### **Type(s) of GHG Reductions**

A cap-and-trade or tax system would directly target the reduction in emissions of the GHGs included in the program. To the extent that generation from coal and oil would decline under a cap-and-trade system, black carbon emissions would also likely decrease.

### **Estimated GHG Reductions and Costs (or Cost Savings)**

Not quantified.

### **Key Uncertainties**

None cited.

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<sup>32</sup> [http://www.ecy.wa.gov/climatechange/docs/07Mar\\_WesternRegionalClimateActionInitiative.pdf](http://www.ecy.wa.gov/climatechange/docs/07Mar_WesternRegionalClimateActionInitiative.pdf)

## **Additional Benefits and Costs**

Effects on or opportunities to assist low-income groups with tax revenue re-distribution are important considerations.

### **Benefits**

Carbon dioxide emissions reductions will typically be accompanied by reductions in the emissions of other air pollutants.

### **Costs**

There is a concern that a Montana-only mechanism would put the state at a competitive disadvantage for attracting and retaining businesses.

## **Feasibility Issues**

The political feasibility of a carbon tax has been widely debated.

## **Status of Group Approval**

Completed.

## **Level of Group Support**

Unanimous consent.

## **Barriers to Consensus**

None.

## **ES-10. Generation Performance Standards or GHG Mitigation Requirements for New (and/or Existing) Generation Facilities, With/Without GHG Offsets**

### **Policy Description**

A generation performance standard (GPS) could take several forms. In the case of a GHG Emissions Performance Standard, as enacted in California and in Washington State, it is a mandate requiring load serving entities (LSEs) to acquire electricity. In the case of a power plant GHG performance standard, as in place in Oregon and Washington, it can be a requirement that power plant developers build and operate new generation, with an emission rate (e.g., X lbs CO<sub>2</sub>/MWh) below a specified mandatory standard that does not exceed a specified GHG emissions profile. In some cases, GHG offsets or credits can be used for compliance (e.g., Oregon and Washington). GHG offsets are GHG emission savings from project-based activities in sectors or regions not covered by the standard or regulations, which typically need to meet specific criteria laid out in the regulation.

A market-based variation of a GPS would allow generators with emission rates lower than the GPS to sell their extra “credits” to generators with emission rates higher than the GPS.

A third variation of a GPS is to establish the standard and allocate allowances based on that standard every year. In this variation, as electricity generation increases, plants would receive more permits. Utilities could trade permits in order to achieve the standard, but there would be no fixed cap on emissions. This variation provides a financial incentive (via the trading) for generators to reduce emissions so that they can sell unneeded permits to generators who have high emissions.

Various GPS policies in place are summarized at the end of this section.

### **Policy Design**

The state should implement Greenhouse Gas Emission Performance Standards and align these standards to the extent possible with those adopted in California and in Washington State. These standards establish a maximum GHG emission rate for new, long-term financial commitments to electricity-generating resources by LSEs and would apply to both in-state and imported electricity (see Table G-7). In doing so, the state should consider a longer-term phase-in to account for the availability of technological options.

Note that this option should complement and work with any future cap-and-trade or carbon tax system (ES-8/9).

**Table G-7. Survey of GHG standards in other states**

State	Start Date	GHG Emissions Performance Standard	Applicability	Additional information
<b>GHG Emission Performance Standards (long-term financial commitments to electrical generating resources)—"load-based"</b>				
California: SB No. 1368 (approved Sep. 2006) <sup>33</sup> CPUC interim opinion (Jan. 2007) <sup>34</sup>	2007	Equal to or less than a new NGCC power plant. Interim rule: 1,100 lbs of CO <sub>2</sub> e/MWh.	New long-term financial commitments to baseload electricity generation by LSEs. (Applies to in-state or imported electricity.)	Ensures no reduction in energy supply reliability.  Emissions based on net emissions from electricity production.  CO <sub>2</sub> stored in geologic formations shall not be counted as emissions from the power plant (interim opinion: for sequestration projects, lifetime emissions count, plan but immediate storage not needed).  Allows for added return where applicable (1/2%–1%) for zero- or low-carbon generating resources.
Washington: SB 6001 <sup>35</sup>	July 1, 2008	Equal to or less than 1,100 lbs of CO <sub>2</sub> e/MWh.	New, long-term financial commitments to baseload electricity generation by IOUs and consumer-owned utilities.	Ensures no reduction in energy supply reliability.  Emissions based on net emissions from electricity production.  CO <sub>2</sub> stored in geologic formations shall not be counted as emissions from the power plant.
<b>Carbon Dioxide Emission Standards For New Energy Facilities—"facility-based"</b>				
Oregon: HB 3283 <sup>36</sup>	1997; updated 2003	Meet emissions standard.  17% better than the most efficient base-load gas plant currently operating in the United States (0.675 lb. CO <sub>2</sub> per kWh).	New energy facilities.	Compliance options: <ul style="list-style-type: none"> <li>• implement offset projects directly;</li> <li>• pay a fee of \$0.85/MtCO<sub>2</sub> using a qualified organization that purchases/manages offsets (below market cost of offsets).</li> </ul>

<sup>33</sup> [http://www.energy.ca.gov/ghgstandards/documents/sb\\_1368\\_bill\\_20060929\\_chaptered.pdf](http://www.energy.ca.gov/ghgstandards/documents/sb_1368_bill_20060929_chaptered.pdf)

<sup>34</sup> [http://www.cpuc.ca.gov/PUBLISHED/FINAL\\_DECISION/64072.htm](http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/64072.htm)

<sup>35</sup> <http://www.leg.wa.gov/pub/billinfo/2007-08/Pdf/Bills/Senate%20Passed%20Legislature/6001-S.PL.pdf>

<sup>36</sup> <http://www.oregon.gov/ENERGY/SITING/docs/ccnewst.pdf> ;

State	Start Date	GHG Emissions Performance Standard	Applicability	Additional information
Washington: HB 3141 & RCW 80.70.020, WAC 173-407	2003; updated 2004	CO <sub>2</sub> mitigation plan to offset 20% of CO <sub>2</sub> e emissions over a 30-year period.	New energy facilities > 350 MW (EFSEC rules); 25–350 MW (Department of Ecology rules); or output increases at existing facilities.	Compliance options: <ul style="list-style-type: none"> <li>• implement offset projects directly;</li> <li>• pay a fee of \$1.60/MtCO<sub>2</sub> using a qualified organization that purchases/manages offsets (below market cost of offsets).</li> </ul>
<b>Carbon Dioxide Emission Standards For Existing Energy Facilities—“facility-based”</b>				
Massachusetts: Amendment to 310 CMR 7.29 <sup>37</sup>	2006 cap; 2008 rate	Cap: Emissions cannot exceed historical emissions Rate: Emissions must not exceed 1,800 lb CO <sub>2</sub> /MWh.	Six current power generation facilities in Massachusetts.	Compliance may be met via emission reductions, avoided emissions, or sequestered emissions.

CPUC = California Public Utility Commission; EFSEC = [Washington] Energy Facility Site Evaluation Council.

**Goals:** Establish a GHG emissions performance standard that

- Applies to new long-term financial commitments to baseload electricity generation by load-serving entities;
- Is equal to or less than a new, NGCC power plant;
- Ensures no reduction in energy supply reliability;
- Is based on net emissions from electricity production;
- Does not count CO<sub>2</sub> stored in geologic formations as emissions from the power plant; and
- Includes a mechanism to update standard as conditions evolve.

**Timing:** The goal is to have a policy in place in 2010.

**Parties Involved:** Under development.

**Other:** None cited.

### Implementation Mechanisms

None cited.

### Related Policies/Programs in Place

In 2007, the regular session of the Montana Legislature adopted HB 25, which repealed most of what remained of Montana’s deregulation law. It also authorized NWE to invest in new power generation facilities, with certain limitations. In situations where NWE might seek advance

<sup>37</sup> [http://trinityconsultants.com/State\\_Regulatory\\_News.asp?st=MA&n=313](http://trinityconsultants.com/State_Regulatory_News.asp?st=MA&n=313); <http://www.mass.gov/dep/air/laws/ghgappb.pdf>

approval for a facility, the new law forbids NWE from acquiring an equity interest in a new coal-fired power plant until the state or federal government has adopted a carbon capture and sequestration standard, unless that plant voluntarily captures and sequesters at least 50% of its carbon dioxide. For power plants that are fueled primarily by natural gas or syngas, NWE would have to obtain certified “cost-effective carbon offsets” in an amount specified by the PSC, but that cannot result in an increase in the price of electricity of more than 2.5%. The definition of offsets includes direct capture at the plant, in addition to market purchases. The PSC is not allowed to approve any such resource until the final air quality permit is in place and the public has had an opportunity to review and comment on it. The PSC is charged with developing rules to implement HB 25 by March 31, 2008. For the final text of the bill, see <http://data.opi.mt.gov/bills/2007/billpdf/HB0025.pdf>

### Type(s) of GHG Benefit(s)

**CO<sub>2</sub>:** A GPS program would directly target reductions CO<sub>2</sub> emissions.

**Black Carbon:** To the extent that generation from coal and oil would decline under a GPS program, black carbon emissions would also decrease.

### Estimated GHG Savings and Costs per Ton

	Policy	Scenario	Reductions		Cumulative Reductions 2007–2020 (MMtCO <sub>2</sub> e)*	NPV 2007–2020 (\$ Millions)	Cost-Effectiveness (\$/tCO <sub>2</sub> )
			2010	2020			
ES-10	Generation Performance Standard	Reference Case–Compliance Mix	0.1	0.8	4.7	\$60	\$13
<i>Range of results depending on compliance option</i>							
ES-10	Generation Performance Standard	Compliance Option 1: NGCC	0.1	0.7	3.9	\$49	\$12
ES-10	Generation Performance Standard	Compliance Option 2: Coal with partial CCS	0.0	0.5	2.7	\$82	\$30
ES-10	Generation Performance Standard	Compliance Option 3: Added renewable energy	0.1	1.2	6.8	\$60	\$9

\* Analyzed on the basis of consumption-based emissions, since the GPS in its design above is focused on load.

### Data Sources, Quantification Methods, and Key Assumptions (for quantified actions)

**Data Sources:** As listed under ES-1 and ES-5.

**Quantification Methods:** The analysis compares the costs and CO<sub>2</sub> emissions of compliance with the GHG Emission Performance Standard, as defined above with the costs and CO<sub>2</sub> emissions of reference case resources. It involves the following steps: 1) estimate the amount of new generation expected to be needed by LSEs to meet load growth, retirements, or terminated contracts; 2) estimate the amount of the likely mix of this new generation needed (based on the inventory/projections); 3) identify the likely amount of generation with emission rates exceeding the performance standard; and 4) estimate the cost of (a mix of) alternative resources that can meet the standard.

## Key Assumptions:

- **Amount of load-serving generation likely to be affected**—A GHG Emission Performance Standard, as described above, would apply to any new long-term financial commitments to baseload electricity generation by LSEs. The challenge is when and where such commitments might be needed. In principle, they would arise where an LSE is in need of new baseload resources due to a) load growth, b) plant retirement or derating, or c) the lapse of existing contracts for baseload resources. Since it is difficult to project b) or c), we simply assume that all new load growth after the start of the policy would be affected by this rule. On one hand, some load growth would be met with existing or non-baseload resources; on the other hand, some new financial commitments will likely arise from cases b) or c). Thus, while imperfect, this approach enables us to make some rough estimates.
- **Replacement mix**—The principal alternatives that meet the GHG Emission Performance Standard would likely be natural gas CC plants, coal with CCSR, or renewable energy facilities. The emissions savings and costs of this policy will depend on the cost-competitiveness (and other factors) of these alternative, replacement resources, as illustrated in Table G-8. For purposes of developing a single estimate, the following replacement mix is assumed:
  - 2010: 50% renewables and 50% natural gas;
  - 2020: 33% renewables, 33% natural gas, 33% coal CCSR.
- **Costs and emissions rate of avoided (coal) resources**—For consistency with other options, the avoided cost (\$49/MWh) is used as a proxy for coal electricity costs. Note that the recent MIT Future of Coal study used as the basis for ES-5 suggests almost the same levelized cost of electricity (\$48.4/MWh) for subcritical PC.
- **Costs of alternative resources**—The busbar cost (a common approach to comparing costs of generation alternatives) uses levelized cents/kWh or \$/MWh of alternative resources based on the same assumptions defined above for renewable energy sources (see ES-1) and coal plants with carbon capture and storage (see ES-5). The cost of natural gas resources is estimated based on information from the EIA’s *Annual Energy Outlook 2006/2007*.<sup>38</sup>

**Table G-8. Characteristics of alternative resources (assumptions)**

Alternative Resource	Bus Bar Cost (\$/MWh)	Emissions Rate (lb CO <sub>2</sub> /MWh)	Incremental Emission Savings (Relative to PC)
Natural gas	\$60	782	58%
Renewable mix	\$41–\$68	0	100%
Coal CCSR	(\$30/tCO <sub>2</sub> )	1,100	40%

## Key Uncertainties

None cited.

<sup>38</sup> [http://www.westgov.org/wieb/electric/Transmission%20Protocol/SSG-WI/pnw\\_5pp\\_02.pdf](http://www.westgov.org/wieb/electric/Transmission%20Protocol/SSG-WI/pnw_5pp_02.pdf)

**Additional Benefits and Costs**

None cited.

**Feasibility Issues**

None cited.

**Status of Group Approval**

Completed.

**Level of Group Support**

Unanimous consent.

**Barriers to Consensus**

None.

## ES-11. Methane and CO<sub>2</sub> Reduction in Oil and Gas Operations, Including Fuel Use and Emissions Reduction in Venting and Flaring

### Policy Description

There are a number of ways in which methane (CH<sub>4</sub>) and CO<sub>2</sub> emissions in the oil and gas industry can be reduced. Natural gas consists primarily of methane; therefore, any leaks during production, processing, and transportation/distribution should be addressed. In addition to reducing GHG emissions, stopping these leaks may be economically beneficial because it can prevent the waste of valuable product.

US EPA's Natural Gas STAR Program offers numerous methods of preventing leaks. These methods, called best management practices (BMPs) and partnership reduction opportunities (PROs), are divided by industry sub-sector: production, processing, and transportation/distribution. Among the practices recommended are preventive maintenance (improving the overall efficiency of the gas production and distribution system), reducing flashing losses (releases when pressure drops at storage tanks, wells, compressor stations, or gas plants), and changing and replacing parts and devices to reduce leaks and improve efficiency.

There are several ways in which CO<sub>2</sub> emissions in the oil and gas industry can be reduced by improving energy efficiency, including a) installing new efficient compressors, b) optimizing gas flow to improve compressor efficiency, c) improving performance of compressor cylinder ends, d) capturing compressor waste heat, e) replacing compressor driver engines, and f) installing waste heat recovery boilers.

Regulations, incentives, and/or support programs can be applied to achieve these reductions (see ES-5 for examples).

### Policy Design

The state should adopt a policy to assist and encourage natural gas companies in the state to participate in EPA's Natural Gas STAR program and provide enforcement and verification of participation. This is especially helpful for a state like Montana where many of the operators are smaller companies that probably have not considered the leak prevention and other methods available through the Natural Gas STAR Program. The Natural Gas STAR Program allows individual companies to work with EPA representatives to develop an implementation plan for BMPs and PROs that are appropriate for that specific company. The state should consider whether participation by smaller companies would be a significant burden and possibly provide incentives if needed.

**Goals:** A goal of reducing methane emissions by 30% below business-as-usual (BAU) levels is suggested based on the analysis of cost-effective, achievable reductions shown below.

**Timing:** The goal should be implemented by 2020.

**Parties Involved:** MDEQ, Bureau of Land Management (BLM), United States Forest Service (USFS), Department of State Lands, Montana Petroleum Association, Society of Petroleum Engineers, and oil and gas companies.

**Other:** None cited.

### Implementation Mechanisms

The state should consider organizing a Natural Gas STAR Program workshop for oil and gas companies operating in-state, in collaboration with US EPA.

MDEQ, along with BLM and the USFS, should develop monitoring capabilities to ensure that BMPs, especially if associated with permit requirements, are fully implemented.

### Related Policies/Programs in Place

**EPA Natural Gas STAR program**—is a voluntary partnership with US EPA, which currently includes several Montana natural gas companies and encourages companies across the natural gas and oil industries to adopt cost-effective technologies and practices that improve operational efficiency and reduce emissions of methane. Natural Gas STAR Program partners sign a Memorandum of Understanding (MOU) wherein they agree to evaluate the Program’s recommended BMPs for reducing methane emissions and implement them when they are cost-effective for the company. Partners develop a customized implementation plan and submit annual reports showing emissions reductions undertaken.

**Remote control of wells and capture of waste gas**—Many oil well operations in eastern Montana are remotely controlled to save vehicle mileage and better prevent spills. Most waste gas is being captured rather than vented in state operations.

### Type(s) of GHG Benefit(s)

**CO<sub>2</sub>:** CO<sub>2</sub> emissions would be reduced directly through the fuel use and flaring reductions.

**CH<sub>4</sub>:** Methane emissions would also be reduced, mostly through decreased venting and leak reductions.

### Estimated GHG Savings and Costs Per Ton

	Policy	Scenario	Reductions		Cumulative Reductions 2007–2020 (MMtCO <sub>2</sub> e)	NPV 2007–2020 (\$ Million)	Cost-Effectiveness (\$/tCO <sub>2</sub> )
			2010	2020			
ES-11	CH <sub>4</sub> /CO <sub>2</sub> Reduction in Oil & Gas Industry	Reference Case	0.1	0.5	3.9	Not yet estimated	Likely net benefit
ES-11	CH <sub>4</sub> /CO <sub>2</sub> Reduction in Oil & Gas Industry	High Fossil Fuel Case	0.3	0.8	6.6	Not yet estimated	Likely net benefit

## Data Sources, Quantification Methods, and Key Assumptions (for quantified actions)

### Data Sources:

- Capital cost and other information for individual technologies and practices are available at EPA's Natural Gas STAR Program Web site, <http://www.epa.gov/gasstar/techprac.htm#tabnav>
- Natural Gas Systems, 1999. US EPA. <http://www.epa.gov/methane/reports/03-naturalgas.pdf>
- Addendum to the U.S. Methane Emissions 1990–2020: 2001 Update for Inventories, Projections, and Opportunities for Reductions. US EPA. <http://www.epa.gov/methane/reports/2001update.pdf>
- Emissions estimates are from the Montana Inventory and Forecast (available at: [www.mtclimatechange.us/CCAC.cfm](http://www.mtclimatechange.us/CCAC.cfm)).

**Table G-9. Methane and carbon dioxide emissions estimates, 2005–2020**

	MMtCO <sub>2</sub> e		
	2005	Reference case 2020	High Fossil Fuel 2020
<b>Methane emissions</b>			
Natural gas industry			
Production	0.43	0.54	1.64
Processing	0.08	0.08	0.08
Transmission	0.57	0.67	0.74
Distribution	0.15	0.28	0.28
Oil industry			
Production	0.26	0.33	0.33
Refining	0.01	0.01	0.01
Transmission and distribution	N/A	N/A	N/A
<b>CO<sub>2</sub> emissions (combustion)</b>			
Natural gas industry			
Production	0.11	0.11	0.12
Processing	N/A	N/A	N/A
Transmission and distribution	0.15	0.28	0.28
Oil industry			
Production	<b>Included in industrial sector</b>		
Refining	2.44	2.44	4.12

**Quantification Methods:** GHG reductions would be based on a specified goal level if one is established. Note that GHG reduction technologies and practices cover a wide variety of actions, and the costs would vary significantly by site and application and are thus difficult to consolidate. A simple, rough, and partial analysis can be conducted for methane emissions in the natural gas industry based on information contained in the US EPA reports noted above. See also

the additional information at the end of this section as provided by the US EPA Natural Gas STAR Program.

### Key Assumptions:

- **Cost and emissions savings (natural gas industry methane emissions)**—As indicated in the national analysis shown in US EPA, 2001. The data in Table G-10 suggest that 30% reductions are achievable at no net cost or net economic savings (due to recovered gas); this estimate is used for the results shown above (assumed to phase in between 2010 and 2015). The implicit assumption is that these national averages are relevant for current Montana conditions, and mix of activities. Some of these emissions reductions may already be underway or completed in the state. (Such efforts would not necessarily be reflected in the inventory/forecast estimates above, which also utilize national average factors.)

**Table G-10. Natural gas emission reductions achievable at different carbon equivalent prices (at 20% discount rate)**

Year (Baseline emissions, MMtCe)	2005 (36.5)		2010 (37.4)		2015 (38.5)		2020 (39.8)	
Carbon Value \$/tCe	Reductions		Reductions		Reductions		Reductions	
(\$20)	3.7	10%	3.8	10%	5.7	15%	7.5	19%
(\$10)	9.1	25%	9.3	25%	9.9	26%	10.5	26%
\$0	10.4	28%	11.2	30%	11.5	30%	11.8	30%
\$10	11.9	33%	12.2	33%	12.6	33%	12.9	33%
\$20	12.2	33%	12.5	33%	12.9	33%	13.3	33%
\$30	12.7	35%	13.0	35%	13.3	35%	13.7	35%
\$40	12.7	35%	13.0	35%	13.6	35%	14.2	36%
\$50	14.6	40%	15.0	40%	15.6	40%	16.2	41%
\$75	16.2	44%	16.6	45%	17.3	45%	17.9	45%
\$100	17.6	48%	18.0	48%	18.7	49%	19.4	49%
\$125	18.2	50%	18.8	50%	19.4	50%	20.1	51%
\$150	18.3	50%	18.8	50%	19.5	51%	20.2	51%
\$175	18.3	50%	18.8	50%	19.5	51%	20.2	51%
\$200	18.3	50%	18.8	50%	19.5	51%	20.2	51%
<b>Remaining emissions</b>	<b>18.2</b>	<b>50%</b>	<b>18.6</b>	<b>50%</b>	<b>19.0</b>	<b>49%</b>	<b>19.6</b>	<b>49%</b>

MMtCe = million metric tons of carbon equivalents.

Source: US EPA, 2001 (applies to methane only)

### Key Uncertainties

None cited.

### Additional Benefits and Costs

None cited.

**Feasibility Issues**

None cited.

**Status of Group Approval**

Completed.

**Level of Group Support**

Unanimous consent.

**Barriers to Consensus**

None.

## Additional Information relevant to ES-11

**Table G-11. Sources of methane emissions from oil and gas activities (1997)**

Industry sector	Natural Gas Industry Sources of Emissions	Percent of Total and Amount	Crude Oil Industry Sources of Emissions	Percent of Total and Amount
Production	Wellheads, dehydrators, separators, gathering lines, and pneumatic devices	25% 8.4 MMtCe or 1.5 Tg	Wellheads, separators, venting and flaring, other treatment equipment	49% 0.7 MMtCe or 0.13 Tg
Processing	Compressors and compressor seals, piping, pneumatic devices, and processing equipment	12% 4.1 MMtCe or 0.7 Tg	Waste gas streams during refining	2% 0.1 MMtCe or 0.01 Tg
Transmission and Storage	Compressor stations (blowdown vents, compressor packing, seals, valves), pneumatic devices, pipeline maintenance, accidents, injection/withdrawal wells, pneumatic devices, and dehydrators	37% 12.4 MMtCe or 2.2 Tg	Transportation tanker operations, crude oil storage tanks	48% 0.7 MMtCe or 0.13 Tg
Distribution	Gate stations, underground non-plastic piping (cast iron mainly), and third-party damage	26% 8.6 MMtCe or 1.5 Tg	Not applicable	
<b>Total</b>		<b>33.5 MMtCe or 5.8 Tg</b>		<b>1.6 MMtCe or 0.27 Tg</b>

Totals may not sum due to independent rounding.

Source: US EPA, 1999 and US EPA, 2000.

The following additional information was provided by US EPA Natural Gas STAR Program representatives:

**Cost curves for methane emissions reduction from oil and gas systems in Montana (\$/tCO<sub>2</sub>)**—While no marginal abatement cost curves for methane emissions reductions are available for Montana, it is reasonable to assume that Montana cost curves will be similar to national estimates. EPA has national pricing and mitigation information available online (<http://www.epa.gov/methane/projections.html>). EPA has analyzed many reduction technologies and their respective reduction efficiencies, as well as U.S.-based capital and operation/maintenance costs. There is also additional data in a recent EPA report titled “Global Mitigation of Non-CO<sub>2</sub> Greenhouse Gases” (EPA Report 430-R-06-005, [www.epa.gov/nonco2/econ-inv/index.html](http://www.epa.gov/nonco2/econ-inv/index.html)). An additional source that may provide food for thought is an article prepared by the Natural Gas STAR Program and published in the *Oil & Gas Journal*, July 12, 2004 ([www.icfi.com/Markets/Energy/doc\\_files/InternationalMethane-oilgasjournal.pdf](http://www.icfi.com/Markets/Energy/doc_files/InternationalMethane-oilgasjournal.pdf)). The article shows that approximately 60% of methane emissions can be mitigated for less than \$10/tCO<sub>2</sub>e.

- **Information regarding specific programs that could be put in place at the state level in Montana to implement methane emissions reductions from oil and gas systems**—The Natural Gas STAR Program maintains a library of technical documents detailing actual

projects that industry partners have found to be cost-effective ways to reduce methane emissions at <http://www.epa.gov/gasstar/resources.htm>. Based on the sector emissions profile and our understanding of pertinent sector-specific emission sources, the following list identifies key opportunities for methane savings:

**Fugitive emissions:**

- Conducting directed inspection and maintenance with optical imaging at production, processing, transmission, and distribution facilities.
- Installing composite wrap for non-leaking pipeline defects.

**Recover gas from designed vents:**

- Reducing methane emissions from pneumatic devices in the natural gas industry.
- Installing rupture pin shutoff devices.
- Installing vapor recovery units.

**Dehydrator emissions:**

- Optimizing glycol circulation and install flash tank separators in dehydrators.
- Installing electric pumps on dehydrators.
- Installing zero-emissions dehydrators.

**Compressor emissions:**

- Replacing wet seals with dry seals in centrifugal compressors.
- Replacing reciprocating compressor rod packing systems.
- Altering operational practices when taking compressors offline.

**Production optimization:**

- Installing plunger lift systems in gas wells.
- Implementing gas well “smart” automation systems.
- Conducting green completions (reduced emissions completions).

## ES-12. GHG Reduction in Refinery Operations, Including in Future Coal-to-Liquids Refineries

### Policy Description

There are a number of ways in which CH<sub>4</sub> and CO<sub>2</sub> emissions can be reduced in the production of liquid fuels at oil refineries or Coal-to-Liquid (CTL) plants. These options include various efficiency measures including enhanced combined heat and power along with carbon capture and storage.

CTL plants are energy-intensive and emit 10 times more CO<sub>2</sub> than conventional oil refineries in order to produce liquid fuels.<sup>39</sup> Emissions reductions from CTL production can be achieved through poly-generation, biomass blending, and most significantly through carbon capture and storage. CTL fuels production is especially amenable to CO<sub>2</sub> capture and sequestration because emissions are largely generated from a single source and are already concentrated, because the syngas produced from the feedstock fuel must be cleansed of excess CO<sub>2</sub> before entering the Fischer-Tropsch reactor.<sup>40</sup> Regulations, incentives, and/or support programs can be applied to achieve these reductions (see ES-5 for some examples).

### Policy Design

There are serious concerns about the high GHG emissions associated with the production of coal liquids. This policy option would require that all CTL facilities located in the State of Montana meet a performance-based standard, reflecting a best available control technology approach, which could imply that

- CTL facilities would capture and store CO<sub>2</sub> from the start of operations, assuming this technology is considered commercially available, producing fuels with 20% to 30% lower life cycle emissions relative to standard petroleum-based fuels.
- Any CTL plant would likely also be a poly-generation plant, and would produce electricity along with fuel and other products.
- In addition, this policy option would aim to improve maintenance at oil refineries and ensure that best practices are being followed (cross-cut with safety issues).

**Goals:** The goal for CTL is to produce fuels with life cycle GHG emissions [at least] 20%–30% below petroleum-based fuels.

**Timing:** Under development.

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<sup>39</sup> International Energy Agency, 2006. *Energy Technology Perspectives*. Well-to-wheel GHG emissions from coal liquids are approximately twice those of conventional oil products. Cogeneration and carbon capture and storage can reduce those emissions to levels similar to, or slightly below, those of conventional oil products.

<sup>40</sup> Brandt, A. R. and A.E. Farrell (2006) Scraping the Bottom of the Barrel: CO<sub>2</sub> Emission Consequences of a Transition to Low-Quality and Synthetic Petroleum Resources. Forthcoming in *Climatic Change*  
[http://erg.berkeley.edu/people/faculty/Brandt\\_Scraping\\_Public.pdf](http://erg.berkeley.edu/people/faculty/Brandt_Scraping_Public.pdf)

**Parties Involved:** Under development.

**Other:** None cited.

### Implementation Mechanisms

Performance standard, as noted above.

### Related Policies/Programs in Place

None identified relating to GHG reductions in refinery operation, including future CTL refineries.

### Type(s) of GHG Benefit(s)

**CO<sub>2</sub>:** CO<sub>2</sub> emissions would be reduced directly through fuel use reductions

**CH<sub>4</sub>:** CH<sub>4</sub> could also be reduced due to process changes (e.g., leak reductions, as appropriate)

### Estimated GHG Savings and Costs Per Ton

	Policy	Scenario	Reductions		Cumulative Reductions 2007–2020 (MMtCO <sub>2</sub> e)	NPV 2007–2020 (\$ Million)	Cost-Effectiveness (\$/tCO <sub>2</sub> )
			2010	2020			
ES-12a	Coal-To-Liquid (CTL) Production	<b>High Fossil Fuel Case</b> CTL—High Fossil Fuel Case: 20%–30% lower life cycle emissions than diesel (via CCS, biomass co-firing, poly-generation)	0	9.9	35	Not estimated	Not estimated
ES-12b	Petroleum Refining	<b>Reference Case</b>	0.02	0.24	1.5	Not estimated	Not estimated
		<b>High Fossil Fuel Case</b>	0.03	0.38	2.2	Not estimated	Not estimated

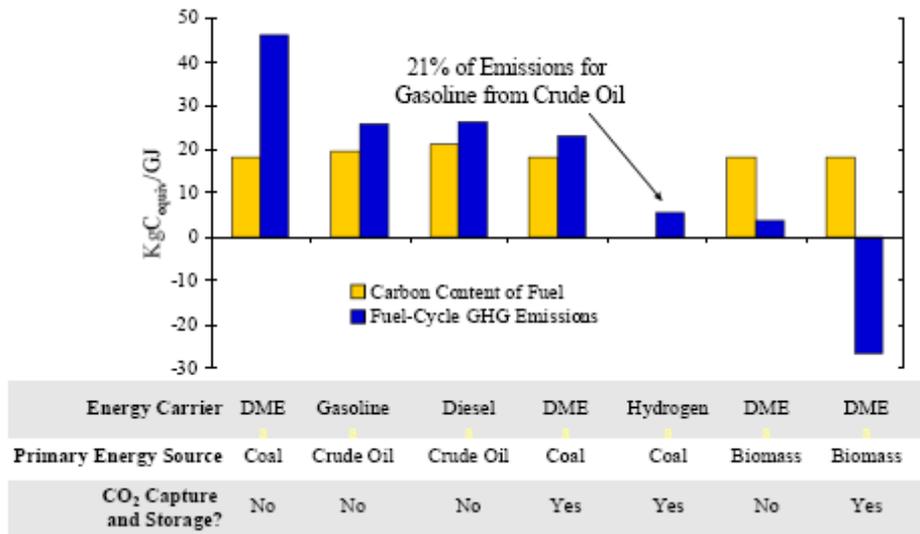
### Data Sources, Quantification Methods, and Key Assumptions (for quantified actions)

#### ES-12a—Coal-To-Liquid (CTL) Production

##### Data Sources:

- R.H. Williams, E. Larson, et al. 2006. Synthetic fuels in a world with high oil and carbon prices. 8th International Conference on Greenhouse Gas Control Technologies, Norway. [http://www.futurecoalfuels.org/documents/032007\\_williams.pdf](http://www.futurecoalfuels.org/documents/032007_williams.pdf)
- R.H. Williams. “\$1 a gallon synthetic liquid fuel with near-zero GHG emissions from coal + biomass using near-term technology.” Congressional Research and Development Caucus, January 27, 2005 (Figure G-2). <http://www.mtclimatechange.us/ewebeditpro/items/O127F10781.pdf>

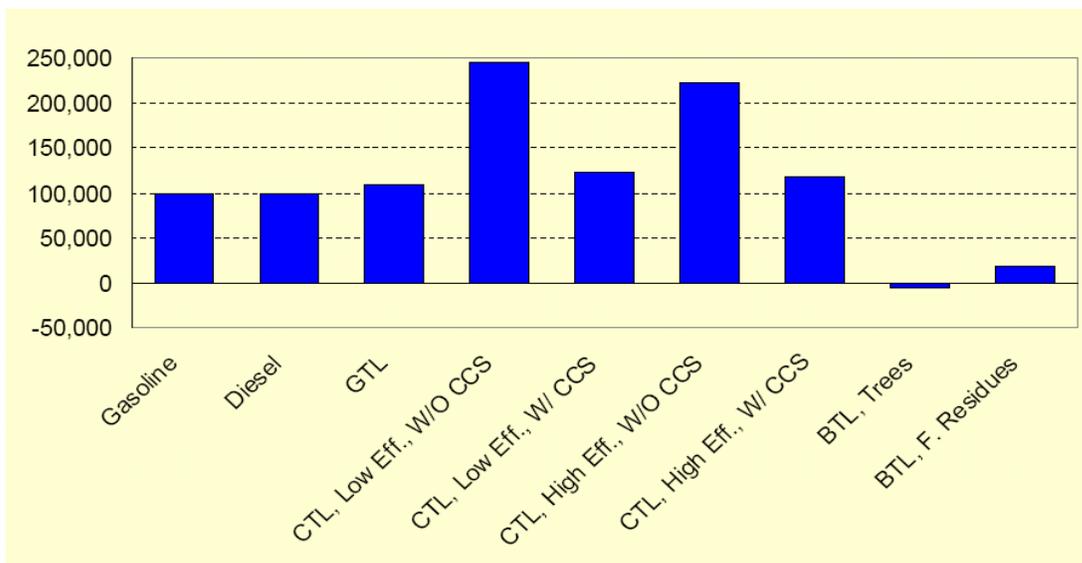
**Figure G-2. Fuel C content, fuel-cycle GHG emissions for a limited sample of fuels/primary energy sources**



DME = dimethyl ether.

- R.H. Williams, and E.D. Larson. 2003. A comparison of direct and indirect liquefaction technologies for making fluid fuels from coal. *Energy for Sustainable Development*, VII:102–129, <http://www.princeton.edu/~energy/publications/pdf/2003/delversussic1.pdf>
- M. Wang, May Wu, and Hong Huo. 2007. “Life-Cycle Energy and Greenhouse Gas Results of Fischer-Tropsch Diesel Produced from Natural Gas, Coal, and Biomass,” Center for Transportation Research, Argonne National Laboratory, 2007 SAE Government/Industry Meeting, Washington, DC, May 14–16, 2007 (Figure G-3).

**Figure G-3. GHG emissions per million Btu of fuel produced and used**



Note: GHG emissions here include CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O. Numerical units of GHG emissions in grams of CO<sub>2</sub>e/mmBtu). CCS not considered for BTL in this study.

BTL = biomass-to-liquids; CCS = carbon capture and storage; CTL = coal-to-liquids.

Source: Wang et al., 2007.

A.R. Brandt, and A.E. Farrell. 2006. “Scraping the Bottom of the Barrel: CO<sub>2</sub> Emission Consequences of a Transition to Low-Quality and Synthetic Petroleum Resources.” Forthcoming in Climatic Change. [http://erg.berkeley.edu/people/faculty/Brandt\\_Scraping\\_Public.pdf](http://erg.berkeley.edu/people/faculty/Brandt_Scraping_Public.pdf)

**Quantification Methods:** Given the large uncertainties and variation among technologies that might be employed for CTL production, quantification is limited to a broad comparison of life cycle emissions impacts. As illustrated above, researchers at the Center for Transportation Research at Argonne National Laboratory (Wang et al., using the GREET model) and Princeton University (Williams et al.) reach similar conclusions regarding the emissions impact of CTL and CCS. Table G-12 uses the results from Wang et al. (2007) since it provides a simple comparison assuming similar fuel output (diesel from CTL). Note that for the Montana GHG inventory, it was assumed that 30% of the CO<sub>2</sub> emissions would be captured and stored.

**Table G-12. Comparison of CTL and carbon capture and storage GHG emissions**

	Life Cycle Emissions Relative to Petroleum Product (Diesel)	Upstream* GHG Emissions in 2020 (MMtCO <sub>2</sub> e)	GHG Emissions Reductions in 2020 (MMtCO <sub>2</sub> e)
CTL production, no CCS	2.25	13.7	–
CTL production (as in high fossil fuel projection, with 30% CCS)	1.73†	7.3	–
CTL production with full CCS	1.23	2.3	5.1
No CTL production	1.0	0	7.3
CTL production with CCS, biomass co-firing, and poly-generation	1.2 to –1.3 (depending on fraction co-fired)	–	5 to 17
ES-12a goal: 20%–30% lower emissions than petroleum products	0.75 (midpoint)	–2.6	9.9

CCS = carbon capture and storage. CTL = coal-to-liquids.

\* Net of emissions from diesel combustion (same in all cases).

† Unlike other figures shown here (full life cycle, multi-gas, from Wang et al., 2007 above), this estimate is based on CO<sub>2</sub> emissions from coal use at the CTL plant only.

**Key Assumptions:** See above.

### ES-12b: Petroleum Refining

**Data Sources:** US EPA, 2007. Energy Trends in Selected Manufacturing Sectors: Opportunities and Challenges for Environmentally Preferable Energy Outcomes.<sup>41</sup>

**Quantification Methods:** US EPA (2007) estimates that energy intensity in the petroleum refinery industry could decline by 0.9% per year in an advanced energy scenario, based on US DOE’s Scenarios for a Clean Energy Future study, which modeled a policy implementation

<sup>41</sup> <http://www.resourcesaver.org/file/toolmanager/CustomO16C45F77356.pdf>

pathway via voluntary energy efficiency commitments.<sup>42</sup> The US EPA and US DOE studies do not estimate cost impacts for individual sectors; the overall savings across the entire U.S. economy is projected at \$80 billion in 2020,+ though the US DOE study suggests overall cost savings in the industrial sector.

**Key Assumptions:** The 0.9% per year rate of decrease in energy use per unit output is assumed to be roughly applicable to existing and potential future refineries in Montana. It is assumed that emissions would decline with energy savings. (The US EPA 2007 study notes that “as the sector’s primary energy source is refinery gas—a byproduct of the production process—there is minimal potential for a large-scale shift toward cleaner fuel inputs.”)

### **Key Uncertainties**

Confirm sufficient availability of biomass supply in state.

### **Additional Benefits and Costs**

As with ES-5.

### **Feasibility Issues**

None cited.

### **Status of Group Approval**

Completed.

### **Level of Group Support**

Unanimous consent.

### **Barriers to Consensus**

None.

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<sup>42</sup> <http://www.ornl.gov/sci/eere/cef/CEFCh5.pdf>

**Table G-13. Opportunity assessment for the petroleum refining industry**

Opportunity	Ranking	Assessment (including potential barriers)
Cleaner fuels	Low	As the sector's primary energy source is refinery gas—a byproduct of the production process—there is minimal potential for a large-scale shift toward cleaner fuel inputs.
Increased CHP	High	<p>Though the petroleum refining industry has relatively low demand for electricity, it has the third-largest cogeneration capacity among manufacturing industries. The industry meets 30 percent of its electricity requirements with onsite power generation, most of which is cogenerated.<sup>282</sup> Due to the magnitude of the industry's steam requirements, cogeneration is generally a cost-effective way of meeting this demand. According to DOE analysis there is substantial potential to increase CHP capacity in the refining industry, and also to increase waste heat reduction and recovery (particularly in lower-quality steam and exit gases).<sup>283</sup> As mentioned previously, DOE expects that in the future, increased synthetic fuel production will be a driver of increased cogenerating capacity to the degree that onsite demand for electricity could be exceeded.<sup>284</sup></p> <p>New CHP installations also face barriers in terms of utility rates and interconnection requirements if electricity production is expected to exceed onsite demand, and also from NSR/PSD permitting.<sup>285</sup></p>
Equipment retrofit/replacement	Medium	<p>For capital-intensive industries, CEF predicts that the largest energy efficiency gains will come from replacement of old equipment with state-of-the-art equipment.<sup>286</sup> Opportunities lie with furnaces, heat exchange equipment (replacement with helical, vertical heat exchangers), sensors and controls, equipment used in separation processes, and containment vessels.<sup>287</sup> Continuous reforming technology improves the efficiency of transportation fuel refining; Digital Equipment Condition Monitoring is a process control technology that allows the system to operate closer to maximum efficiency. Retrofits can also reduce energy losses from steam systems (pipes, traps, and valves).</p> <p>API cites cost and regulatory barriers to energy efficiency improvement, noting "energy efficiency is not usually a business driver and is difficult to justify as an investment when capital recovery is too long."<sup>288</sup> To avoid NSR, refineries may find it easier to retrofit existing equipment as opposed to installing the latest energy-efficient technologies.</p>
Process improvement	Medium	<p>The most energy-intensive processes in petroleum refining include distillation (atmospheric and vacuum), hydrotreating, alkylation, and reforming.<sup>289</sup> Energy losses can be reduced through implementation of energy management best practices, minimization of energy-intensive processes such as distillation, process optimization to reduce downtime and maintenance requirements, and replacement of solid phase catalysts with ionic liquids.<sup>290</sup> API has the objective of increasing usage of less energy-intensive biological processes, including bioprocessing of crude, biotreatment of wastewater, and bioremediation of soil and groundwater contamination.</p> <p>API cites uncertainties about future product requirements as inhibiting some process-related changes. There is uncertainty about future performance-related requirements on the part of consumers, as well as uncertainty about future regulatory requirements.<sup>291</sup></p>
R&D	Medium	<p>API notes the following R&amp;D focus areas: replacements for existing separation processes, improved process yields through development of more selective catalysts, development of better pathways for hydrocarbon conversion, and bioprocessing.<sup>292</sup> Promising technologies are currently in development, such as membrane separation technologies that increase the efficiency of distillation units by 20 percent.</p> <p>Under Climate VISION, the R&amp;D Challenge focuses on technologies that reduce/sequester carbon emissions.<sup>293</sup> The industry has developed mission statements and roadmaps for crucial R&amp;D priority efforts as part of its efforts with DOE/IOF; see <a href="http://www.eere.energy.gov/industry/petroleum_refining/">http://www.eere.energy.gov/industry/petroleum_refining/</a>. With the elimination of most of the nation's small, inefficient refineries and expansion of remaining, larger, more efficient refineries, refining margins have improved in 2004 and 2005. The industry's strengthened financial position may help attract capital necessary for R&amp;D and other large-scale improvements.</p> <p>API notes the following factors that inhibit the development of new energy-saving technologies and processes in the petroleum refining industry: a number of technical barriers (intrinsic process inefficiency, lack of understanding about mechanisms leading to fouling, inadequate sensing and measuring techniques, inadequate process models), regulatory requirements, costs and risks associated with developing new technology, and a lack of long-term commitment to fundamental research.<sup>294</sup></p>

## **ES-13. CO<sub>2</sub> Capture and Storage or Reuse (CCSR) in Oil & Gas Operations, Including Refineries and Coal-to-Liquids Operations**

**Note:** Due to overlaps with other options, CCSR is now considered within ES-5 and ES-12 and is no longer considered separately.

## Attachment A: Survey of Carbon Tax Programs

Jurisdiction	Status: Start Date	Tax Rate–Applicability	Where Tax Applied	Use of Revenue
Finland <sup>1</sup>	1990 Revised 1997 Revised 2002	1990 \$1.54 per ton 1993 \$3.00 per ton 1997–1998 Electricity: \$0.007 per kWh Heating: \$22.53 per ton CO <sub>2</sub> Natural gas: \$11.26 per ton CO <sub>2</sub>	1990 Fuels  1997 Electricity consumption not fuels reduced for industry  Exemption for international aviation, shipping, and refineries	Reimbursement via lower payroll taxes
Norway <sup>2</sup>	1991 Revised 1999	Petrol: \$55.90 per ton CO <sub>2</sub> Mineral Oil: \$30.16 per ton CO <sub>2</sub> Oil and gas in North Sea: \$52.05 per ton CO <sub>2</sub>	Producers and importers of oil products  Exemption for foreign shipping, fishing, external aviation	Reduce other taxes
Sweden <sup>3</sup>	1991 Revised 2004	CO <sub>2</sub> : \$100 per ton 2004 increases: Gasoline: \$0.02 per L Diesel: \$0.04 per L Vehicle Tax Electricity: \$0.002 per kWh (excludes industry)	Oil, coal, natural gas, liquefied petroleum gas, petrol, and domestic aviation fuel  Reduced industrial rate  Exemption for high-energy industries, i.e., horticulture, mining, manufacturing, and pulp/paper industry	Offset by income tax relief  Est. revenue \$523 million
Denmark <sup>4</sup>	1992 Revised 1999	Commercial \$14.30 per ton CO <sub>2</sub> Households \$7.15 per ton CO <sub>2</sub>	Buildings	Reallocated as subsidies for energy efficiency activities and voluntary agreements

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Germany <sup>5</sup>	1999 Revised 2000	1999 Gasoline: \$0.04 per L Heating fuel: \$0.03 per L Natural gas:\$0.02 per kWh Electricity: \$0.01 per kWh 2000-2003 annual increases Gasoline: \$0.04 per L Electricity: \$0.003 per kWh	Electricity, heating fuel, natural gas, gasoline	Tax breaks for commuters; Reduce labor costs via pension contributions
Japan <sup>6</sup>	2001	Green taxation Subsidies for high efficiency automobiles	Vehicles	
UK	2001-	Electricity: \$0.0084 per kWh Coal and Natural gas: \$0.0029 per kWh Levy will rise with inflation annually beginning in 2007	Electricity generation includes nuclear Renewable exempt	Reduced National Insurance rate Fund for energy efficiency initiatives
Netherlands	2005	Fossil electricity: \$0.08 per kWh for small consumers Renewable exemption: \$0.04 per kWh Rates indexed to inflation.	Electricity and fuel consumption. Renewable sources with green certificate exempt.	Reduced income and corporate tax rates
City of Boulder, CO	Approved 2006 Start 2007 Expiration 2013	Electricity: (kWh) \$.0022 for residential \$0.0004 for commercial \$0.0002 for industrial use Max increases: \$0.0049 for residential \$0.0009 for commercial \$0.0003 for industrial use	Electricity use	Funding for city's Climate Action Plan: Programs to increase energy efficiency, renewable energy use, reduce motor vehicle emissions, and take further steps to meeting Kyoto protocol targets

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Australia: State of West Australia <sup>7</sup>	Under current consideration	\$19.58 per ton CO <sub>2</sub>		
Canada: Province of Quebec <sup>8</sup>	2006	To be determined by Quebec Energy Board \$1 billion est. 6-year revenue	Non-renewable fossil fuels sold in bulk to retailers	Green Fund: Public transportation, energy efficiency for buildings

<sup>1</sup> <http://www.norden.org/pub/ebook/2001-566.pdf>;

<sup>2</sup> <http://ideas.repec.org/p/ssb/dispap/337.html>

<sup>3</sup> <http://pubs.acs.org/hotartcl/est/98/dec/hanish.html>

<sup>4</sup> <http://www.iea.org/Textbase/pm/?mode=cc&id=156&action=detail>

<sup>5</sup> [http://www.iea.org/textbase/publications/free\\_new\\_Desc.asp?PUBS\\_ID=1097](http://www.iea.org/textbase/publications/free_new_Desc.asp?PUBS_ID=1097)

<sup>6</sup> <http://www.iea.org/textbase/nppdf/free/2000/japan2003.pdf>

<sup>7</sup> <http://www.news.com.au/story/0,23599,21171914-2,00.html>

<sup>8</sup> <http://www.cbc.ca/news/background/kyoto/carbon-tax.html>