Energy Supply Technical Work Group
Summary List of Recommended High Priority Mitigation Options

	Policy Option		GHG Reductions ($MMtCO_2e$) 2010	2020	Total 2007–2020	Net Present Value 2007–2020 (Million $)	Cost-Effective-ness ($\$/tCO_2e$)	Status of Option
ES-1	Environmental Portfolio Standard (Renewables and Energy Efficiency)	Efficiency/ Conservation	0.03	0.92	5.4	–$79	–$15	Completed
		Renewable Energy	0.0	1.6	5.5	$53	$10	
ES-2	Renewable Energy Incentives (Biomass, Wind, Solar, Geothermal)		Not Quantified Separately (see ES-1 and ES-4)					Completed
ES-3	Research and Development (R&D), Including R&D for Energy Storage and Advanced Fossil Fuel Technologies		Not Quantified					Completed
ES-4	Incentives and Barrier Removal (Including Interconnection Rules and Net Metering Arrangements) for Combined Heat and Power (CHP) and Clean Distributed Generation (DG)	Distributed Renewables	0.03	0.10	0.8	$16	$21	Completed
		Combined Heat and Power	0.2	0.7	5.0	$81	$16	
ES-5	Incentives for Advanced Fossil Fuel Generation and Carbon Capture and Storage (CCS), Including Combined Hydrogen and Electricity Production with Carbon Sequestration	Reference Case	0	1.0	4.5	$135	$30	Completed
		High Fossil Scenario	0	5.2	24.4	$733	$30	
ES-6	Efficiency Improvements and Repowering of Existing Plants		Not Quantified					Completed
ES-7	Demand-Side Management		Not Quantified Separately (see ES-1 and RCII-1)					Moved to RCI
ES-8/9	Market-Based Mechanisms to Establish a Price Signal for GHG Emissions (GHG Cap-and-Trade or Tax)		Not Quantified					Completed
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	Completed

	Policy Option		GHG Reductions ($MMtCO_2e$)			Net Present Value 2007–2020 (Million $)	Cost-Effective-ness ($/tCO_2e$)	Status of Option
			2010	**2020**	**Total 2007–2020**			
ES-11	Methane and CO_2 Reduction in Oil and Gas Operations, Including Fuel Use and Emissions Reduction in Venting and Flaring	Reference Case	0.1	0.5	3.9	Not estimated	Likely net benefit	Completed
		High Fossil Fuel Case	0.3	0.8	6.6	Not estimated	Likely net benefit	
ES-12	GHG Reduction in Refinery Operations, Including in Future Coal-to-Liquids Refineries	Coal-to-Liquids—High Fossil Fuel Case	0	9.9	35	Not estimated	Not estimated	Completed
		Petroleum Refining—Reference Case	0.02	0.24	1.5	Not estimated	Not estimated	
		Petroleum Refining—High Fossil Case	0.03	0.38	2.2	Not estimated	Not estimated	
ES-13	CO_2 Capture and Storage or Reuse (CCSR) in Oil & Gas Operations, Including Refineries and Coal-to-Liquids Operations		Incorporated in ES-5 and 12					Completed
Sector Total After Adjusting for Overlaps (among ES options and after demand reductions from RCI options)		**Reference Case**	**0.4**	**4.2**	**21.9**	**$272**	**$17**	
		High Fossil Fuel Case	0.4	18.7	79.4	$870	$24	

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 (GHG) Emission Reductions

The Climate Change Advisory Committee (CCAC) process has discussed two accounting approaches for estimating electricity emissions: (a) the consumption-basis approach, which aims to reflect the emissions associated with electricity sources used to deliver electricity to consumers in the state; and (b) 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/ 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 have a direct focus 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-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: Advanced Fossil Fuel 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 future Montana's GHG emissions from the electric 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 emission reductions associated with several of the Energy Supply 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 this 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, which 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 options 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.

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) that 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 (RECs) 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.[1]

Goals: Each investor-owned and public utility (including member-owned electric co-operatives) 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 two years.

    "Energy conservation" refers to both electricity and natural gas.

Timing: See above.

Parties Involved: Investor-owned utilities, electric cooperatives, Montana PSC, state government.

Other: None cited.

Implementation Mechanisms

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

[1] 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.]
- Definition of “cost-effective” and strategies (incentives/penalties) to ensure that the energy savings are achieved.
- Adjustment of cost cap in existing bill.
- Consider possibility of different standards for cost cap to apply to IOUs and co-operatives.

Given concerns as to how an RPS could be enforced with respect to electric cooperatives (since co-operatives are not regulated by the Public Service Commission), further investigation of regarding enforcement mechanisms for cooperatives is needed.

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

Related Policies/Programs in Place

Montana’s renewables portfolio standard (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, 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 megawatts 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 (1) located in Montana or (2) 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 pre-approved by the Montana Public Service Commission (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.[2]

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_2: 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_2 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	($MMtCO_2e$)*		NPV (2007–2020)($ Million)	Cost Effectiveness ($/tCO_2$)
			2010	2020	Cumulative Reductions (2007–2020)		
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†

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.

† 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 Governor's Association 2006 (WGA 2006) *Task Force Reports from the Clean and Diversified Energy Initiative,*[3] Energy Information Administration (EIA) Annual Energy Outlook (AEO),[4] National Renewable Energy Laboratory.[5]
  - Other data sources as noted below.

[2] www.dsireusa.org/library/includes/tabsrch.cfm?state=MT&type=RPS&back=regtab&Sector=S&CurrentPageID=7&EE=1&RE=1
[3] http://www.westgov.org/wga/initiatives/cdeac/index.htm
[4] http://www.eia.doe.gov/oiaf/aeo/assumption/index.html
[5] http://www.nrel.gov/analysis/power_databook/

- **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 is 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 Renewable Portfolio Standard (see 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 onto 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 ten 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 CDEAC.[6]
  - **Reference technology costs:** For overall consistency, we use technology costs from EIA's Annual Energy Outlook (AEO) for 2007.[7] While recently prices have gone up significantly for wind turbines, as well as for other technologies including coal units due

[6] CDEAC Transmission Report in the High Renewables case has an average incremental transmission cost of 80 $/kW compared to the reference case, i.e., 84,641 MW incremental capacity with additional transmission expansion costs of $6,786 million.
[7] Electric Market Module, EIA Assumptions to the Annual Energy Outlook 2006.

to tight markets and high materials prices, these estimates reflect a longer-term view. See discussion under "key uncertainties" (Table G-1).

Table G-1.

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

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.[8]

- **Wind integration costs:** The cost of integrating wind at various levels of wind penetration is estimated based on 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)[9]. 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 Public Service Commissions. ($49 per MWh).[10]
- **Avoided electricity emissions:** see description in the above "Approach" section on avoided emissions.

[8] http://www.eia.doe.gov/oiaf/aeo/assumption/index.html

[9] http://www.nwcouncil.org/energy/Wind/library/2007-1.pdf

[10] 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 $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 NWE/PPL document by including values for 2015 to 2020 that increment the 2014 average value at the rate of inflation, levelizes the resulting 2007 to 2020 stream, and adjusts the levelized value to 2005 dollars.

Key Uncertainties

Capital costs: Wind capital costs used for the analysis above (around $1200/kW) are based on USDOE's most recent long-term projections. In the past couple of years, wind capital costs have been higher than these levels.[11] Some recent utility Integrated Resource Plans suggest the current capital costs of a 100-200 MW facility may be as high as $1700kW (not including land/site acquisition).[12] This higher cost appears to be due in large part to an increase in the costs of materials (e.g., steel) and from 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 (PTC): As noted, costs for renewable energy are highly dependent on assumptions regarding Federal Production Tax Credit. 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 Judith Gap project came on line the reported cost for wind integration was approximately $7/MWh.[13] However, NorthWestern Energy 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.

Montana utilities that need to assume the cost of wind integration will be exposed to these market prices since, at present, Montana utilities lack resources of their own that could provide an integration product. If costs for integration services become very expensive—which could be as high as $14-20/MWh[14]—and if other measures to reduce the need for such services are not undertaken, achieving the renewable energy goals set forth here could result in wind power costs being considerably higher than the costs of other resources and could cause underestimation of the costs to implement this recommendation.

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[11] Recent utility plans in the region have used the following costs: Avista 2005 IRP–$1191 (100 MW), IPC 2006 IRP–$1610 (100 MW), NWE 2006 DSP–$1010 (100 MW), NWPCC 2007 Report (2006$)–$1500 (150 MW), PacifiCorps 2004 IRP update (2005$)–$1474 (50 MW), Portland General 2007 IRP (2006$)–$1700 (100 MW). Puget Sound 2005 IRP (2006$)–$1438 (150 MW), Seattle City Light 2006 Draft IRP (2006$)–$1500.

[12] 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.

[13] "NorthWestern Energy 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 NorthWestern control area has a wind penetration of 8.7 percent and is currently purchasing all of its control area services at market-based rates." Northwest Wind Integration Action Plan, March 2007.

[14] For example, preliminary wind integration costs supplied by Idaho Power were at $16/MWh for penetration at 30% of system Northwest Wind Integration Action Plan, March 2007. $20/MWh was used to explore the sensitivity of this value on cost-effectiveness estimates.

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 are $1800/kW, rather than the initial assumption of $1,194/kW—the estimated costs of the option will *increase* by $67 million (net present value) or $12/metric ton CO_2e, 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 (net present value) and the cost-effectiveness is about $22/metric ton CO_2e. Using the assumption that the PTC will be extended to 2015, the initial costs would *decline* by $19 million (net present value) or $3/metric ton CO_2e. Assuming both the higher capital cost of wind and a 2015 extension of the PTC, leads to an increased cost of $48 million (net present value) or $9/metric ton CO_2e.

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

			Change in Results, Relative to Initial Assumptions	
	Initial Assumption	**Alternative Assumption**	**Costs ($ millions)**	**Cost Effectiveness ($/$tCO_2$)**
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**	**-$3**
Wind Capacity Fraction of System Peak	**Average Wind Integration Cost ($/MWh of Wind Generation)**		**+$35**	**+$6**
0%	$0	$0		
5%	$3	$7		
10%	$6	$20		
20%	$8	$20		
30%	$12.5	$20		

Sources: Initial Assumptions, see above; Alternative Assumptions, based on general ranges determined during research. Alternatives for the capital cost of wind-based on sources in footnote 12 and wind integration costs were suggested by 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 Public Service Commission (PSC) and Montana's representatives on the Northwest Power and Conservation Council, 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 to 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 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 end of 2009.

Parties Involved: PSC, NWPPC, State Government, Utilities

Other: None cited.

Implementation Mechanisms

Could include the following:

- Tax policies, production tax credits (federal), Public Utility Regulatory Policy Act (PURPA) requirements (Montana has mini-PURPA law).
- Montana's HB 3 from the 2007 Special Session—The "Clean and Green" 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 House Bill 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 projects that have implemented measures in project construction and operation so as to minimize impacts" to wildlife, critical wildlife habitat, national and state parks, and other areas of special concern. The DEQ should work collaboratively with stakeholders to establish the criteria for such a system in order to formalize the best management practices that Montanans agree make sense for active but low-impact wind power development.

Related Policies/Programs in Place

Related policies and programs include:

- **Montana House Bill 3 ("Clean 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, "clean" liquid and 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, natural gas combined cycle with carbon offsets, transmission lines and pipelines carrying "clean" products or CO_2, 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 line is exempt from property tax. To receive these benefits, DEQ must certify the projects meet the conditions of the bill.

- **Tax incentives for renewable energy—**A variety of tax incentives are available for individuals and businesses.[15] 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 five 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 using 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)—**NorthWestern Energy 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 (House Bill 330)—**This recently enacted legislation enables local government bond financing of renewable energy projects. [16]

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 incentives are able to 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.

[15] A summary can be found at: http://deq.mt.gov/Energy/Renewable/TaxIncentRenew.asp
[16] 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 FutureGen process as a potential source of lessons on how to develop and succeed at funding a demonstration project. Demonstration projects are typically located nearby to active R&D programs.
- Establish emerging energy technology program in 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 Sequestration Partnership as a model. Choose areas for R&D that match well with the Montana resource base.[17] Target, among other technologies, 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 Big Sky Sequestration partnership.
- Seek industry participation and contributions (e.g., licensing fees) to help pay for R&D activities.
- Make available the results of R&D and pilot programs to inform industrial development.

[17] Montana has significant coal reserves as well as a number of promising sites for CO_2 storage and enhanced oil recovery. For instance, Southern Montana Electric has suggested that its proposed facility (HGS) 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 demonstrating economic feasibility.

- 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 research and development projects or renewable resource research and development projects.[18]).

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 (BSCSP)—**Led by Montana State University, BSCSP is one of the U.S. Department of Energy's (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 (ZERT)—**is a partnership involving Montana State University, as well as 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 greenhouse gasses 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 both Illinois and Texas are being evaluated for siting of the FutureGen project.

Type(s) of GHG Reductions

Under development.

Estimated GHG Reductions and Costs (or Cost Savings)

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

[18] HB 715, http://data.opi.mt.gov/bills/2007/billpdf/HB0715.pdf

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 & Power CHP) and Clean Distributed Generation (DG)

Policy Description

This option is focused on combined heat and power (CHP) and distributed generation (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, exit fees, etc. 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:[19]

- Create standardized interconnection rules for CHP and DG systems to increase investor and developer certainty and predictability and reduce transaction costs.
- Consider offering different interconnection and net metering rules for smaller (residential-size, 5-10 kW) systems, as it might be easier for cooperatives to agree on a standard for these systems than for larger systems.
- Remove 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.
- Increase incentives for installing CHP and DG systems.
- Increase incentives for the development of small distributed wind systems.
- Increase incentives for the development of solar hot water.
- Improve or expand the Alternative energy Revolving Loan Program (supported by air pollution non-compliance fees[20]) to defray some of initial costs of CHP and DG systems.

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[19] 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.

[20] 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 Casey A. Barrs, and available at

- Encourage 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 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.
- Consider clean CHP as a net-metering eligible resource.
- Consider establishing a DG effort similar to the establishment of the Rural Electrification Administration in the 1930s that was able 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 12/31/01 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 four taxable years.
- **Residential Geothermal Systems Credit (15-32-115 MCA)—**Resident taxpayers of Montana 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.
- **Bonneville Environmental Foundation (BEF) - Renewable Energy Grant—**Using revenues generated from the sales of Green Tags, BEF, a not-for-profit organization, accepts

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http://leg.mt.gov/content/committees/interim/2005_2006/energy_telecom/staff_reports/DEG_consolidated_8-21-06%20(2).pdf proposals for funding renewable energy projects located in the Pacific Northwest (OR, WA, ID, MT). Any private person, organization, local or tribal government located in the Pacific Northwest may participate. Projects that generate electricity are preferred. Acceptable projects include solar photovoltaics, 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 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 provides curriculum modules developed for schools. The school agrees to own and maintain the solar 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 (AERLP) (75-25-101 MCA)—P**rovides 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 Department of Environmental Quality. In 2005, Senate Bill 50 amended the loan program, increasing maximum loan amount to $40,000 (subject to available funds) and extending the repayment period to ten 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 on 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 NorthWestern Energy 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. NorthWestern Energy (Montana Power) 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. NorthWestern 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_2: 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_2 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

			Reductions	($MMtCO_2e$)*			
	Policy	**Scenario**	**2010**	**2020**	**Cumulative Reductions (2007–2020)**	**NPV (2007–2020) $ millions**	**Cost-Effective-ness $/tCO$_2$**
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:** Western Governors Association'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 photovoltaic (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 2020.21

    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 Western Governors' Association estimate of an achievable goal of 500,000 systems installed by 2015 for entire region. The MT fraction was estimated using same fraction as used for WGA estimates of Solar PV by state (accounting for electricity use, solar insulation [the amount of sunlight/solar radiation], and population growth).

  - **Technology costs:** from Western Governors' Association 2006 (WGA 2006) Task Force Reports from the Clean and Diversified Energy Initiative,[22] Energy Information Administration,[23]; and, Energy Trust of Oregon.[24]

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

b) Combined Heat and Power (CHP)

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[21] Personal communication, Pat Judge MEIC and Chris Daum, Oasis Montana, February 2007.
[22] http://www.westgov.org/wga/initiatives/cdeac/index.htm
[23] http://www.eia.doe.gov/oiaf/aeo/assumption/index.html
[24] *A Comparative Analysis of Community Wind Power Development Options in Oregon*
http://www.oregon.gov/ENERGY/RENEW/Wind/docs/CommunityWindReportLBLforETO.pdf

- **Data Sources:**
  - The *Combined Heat and Power White Paper*, dated January, 2006, to the Clean and Diversified Energy Initiative (CDEI) of the Western Governors Association; and the *2003 Commercial Buildings Energy Consumption Survey Detailed Tables*, published by the US Department of Energy's Energy Information Administration.
- **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 is based on a potential of 470 MW (per the WGA/CDEI source above)[25]; this potential grows with commercial and industrial loads; and the potential and 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 5000 hours per year (at full capacity), and 90 percent 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 policy.

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

Key Uncertainties

None cited.

Additional Benefits and Costs

None cited.

Feasibility Issues

None cited.

[25] An alternate estimate of CHP potential is 1092 MW from a 2004 analysis by the Western Resource Advocates, *A Balanced Energy Plan for the Interior West*. http://www.westernresourceadvocates.org/energy/clenergy.php

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_2 emissions per kWh as the result of more efficient generating technologies (supercritical coal, integrated gasification combined cycle, etc.) and/or carbon capture and storage or reuse (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_2 emission rate. Incentives may be in the form of direct subsidies, assistance in securing financing and/or off-take agreements, or a guarantee cost recovery for prudently incurred utility investments.

Policy Design

This policy option would:

- Direct DEQ 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_2 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 tCO2/MWh.As needed to achieve this level, facilities must file a plan with the Montana Department of Environmental Quality, 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 DEQ petition the Board of Environmental Review 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_2/MWh (or 1100 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: TBD.

Parties Involved: Electrical generating facilities, Montana PSC, DEQ.

Other: None cited.

Implementation Mechanisms

Carbon Sequestration: Rule changes would have to be made by the DEQ to the Major Facility Siting Act regarding sequestration pipelines, and then brought before the Board of Environmental Review for approval.

Technology Emissions Level Requirement: A rule would have to be established by the Board of Environmental Review that requires all fossil fuel fired electric generation facilities to meet a technology/fuel-neutral emissions level expressed in tCO_2/MWh. Upon finalization of such a rule, the DEQ 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_2, DEQ would verify compliance with the applicable standards.

Related Policies/Programs in Place

Montana House Bill 3 ("Clean 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, "clean" liquid and 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, natural gas combined cycle with carbon offsets, transmission lines and pipelines carrying "clean" products or CO_2, 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 line is exempt from property tax. To receive these benefits, DEQ 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 Department.

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

Type(s) of GHG Benefit(s)

- CO_2: Reductions in CO_2 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 2010	(MMtCO$_2$e)* 2020	Cumulative Reductions (2007–2020)	NPV (2007–2020) $ Million	Cost-Effective-ness $/tCO$_2$
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_2 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 MIT report, "The Future of Coal" (2007)[26] which provides estimates of costs and emissions savings from various coal technologies with and without carbon capture and storage.
  - The IPCC Special Report on Carbon Dioxide Capture and Storage (2006)[27] which provides other estimates, including rough estimates of the costs of CO_2 transport and storage.
  - 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_2 capture, accounting also for high elevation issues with IGCC as might be encountered in Montana.
  - Advanced Coal Task force report and spreadsheets from Western Governor's Association 2006 (WGA 2006) *Clean and Diversified Energy Initiative*[28]
- **Quantification Methods:** See additional information at the end of this section.

[26] http://web.mit.edu/coal/
[27] http://www.ipcc.ch/activity/srccs/index.htm
[28] http://www.westgov.org/wga/initiatives/cdeac/index.htm

- **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 case (See the inventory/forecast documentation.) 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_2 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_2 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 CO_2 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_2 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_2 capture and pressurization (about $25/tonne) and CO_2 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 $/tCO_2$ avoided, transported, or stored)

	MIT, 2007	IPCC, 2006**	EPA, 2006
New PC or FBC coal plant with CCS	$39–$48*†	$30–$70 $10–$40 (with EOR)	$35 (supercritical)
New IGCC plant with CCS (avoided cost)	$19–$24*	$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 & verification	$0.5–$2 transport (220 miles)
Overall reduction in CO_2 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 combustion.

All estimates are for CO_2 avoided; and assumed 90% capture.

* Low end of range generally reflects avoided plant is the same technology; high end of range generally reflects avoidance of a supercritical (high efficiency) PC plant.

** Reference plant is a PC coal plant

† Range reflects several plant types: subcritical, supercritical, fluidized bed, etc.

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_2 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

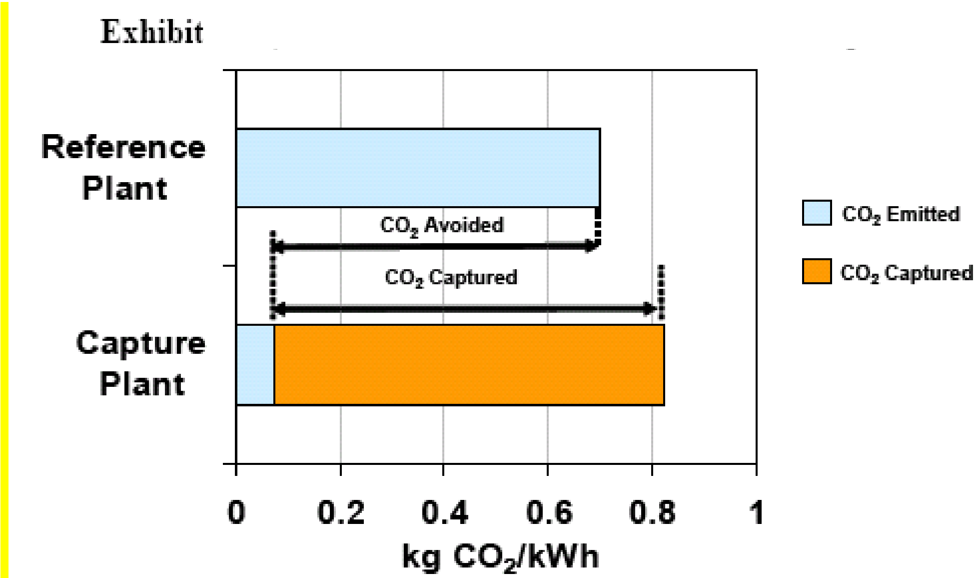
Unanimous consent.

Barriers to Consensus

None.

Additional information related to ES-5

Figure G-1. Illustration of avoided cost for CO_2 capture.



Source: USEPA, 2006

All costs shown above reflect "avoided costs" not "capture costs," i.e., costs are spread over the amount of CO_2 avoided, which is less than the amount of CO_2 captured.

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 at coal plants fuels 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_2 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 group.

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 greenhouse gas emissions (or carbon dioxide specifically) is considered essential in order to reduce greenhouse gas 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_2, would be a tax on each ton of CO_2 (equivalents) emitted from an emissions source covered by the tax. A CO_2 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_2 emissions in products and services, and would adjust their behavior to purchase substitute goods and services that result in lower CO_2 emissions. CO_2 tax revenue could be used in a variety of ways such as payroll or income tax reductions or policies and programs to assist in decreasing CO_2 emissions. CO_2 tax revenue could also be directed to helping the competitiveness of industries or assisting communities most affected by the tax.

A cap and trade system utilizes 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_2). 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 otherwise be.

For every ton of CO_2 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, how “leakage”[29] is addressed, etc. 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, regionally, etc.); and whether compliance with the cap could be achieved given “leakage” from non-participating 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 effective 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 multi-state effort so as to take advantage of a larger market to conduct 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 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 state-wide 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 that think they will benefit from it.

There is one regional GHG cap-and-trade system in the US in the process of being implemented in the United States, 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.[30] The Western Climate Initiative, (WCI) is an effort by 6 states (Washington, California, Oregon, Arizona, New Mexico, Utah) and two Canadian provinces (British Columbia and Manitoba), that aims to design “a regional market-based multi-sector mechanism, such as a load-based cap and

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

[30] http://www.rggi.org/

trade program, to achieve the regional GHG reduction goal."[31] In contrast to RGGI, the Western Climate Initiative is economy-wide. While the exact mechanism to be used is not yet 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 are accommodated, and how leakage is 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 non participating states and coal-fired generation 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

[31] Joining after the initiative was announced was the State of Utah and the Provinces of BC and Manitoba.

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 US today is the Northeast States' Regional Greenhouse Gas Initiative: http://www.rggi.org/.

Various carbon tax policies in place are summarized in Appendix A.

In February 2007, Washington, California, Oregon, Arizona, and New Mexico signed the Western Regional Climate Action Initiative. It 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."[32]

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 greenhouse gases 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.

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.

[32] http://www.ecy.wa.gov/climatechange/docs/07Mar_WesternRegionalClimateActionInitiative.pdf

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 (LSE) 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_2/MWh) below a specified mandatory standard. In some cases, GHG offsets or credits can be used for compliance (e.g., OR and WA). 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 electrical generating resources by load-serving entities, and would apply to both in-state and imported electricity (see Table G-7, Survey of Greenhouse Gas Standards in Other States). 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 Greenhouse Gas Standards in Other States.

State	Start Date	GHG Emissions Performance Standard	Applicability	Additional information
Greenhouse Gas Emission Performance Standards (Long-term financial commitments to electrical generating resources)—"load-based"				
California: Senate Bill No. 1368 (approved Sep 2006)[33] CPUC interim opinion (Jan 2007)[34]	2007	Equal to or less than a new, combined-cycle natural gas power plant. Interim rule: 1100 lbs of CO_2e/MWh	New long-term financial commitments to baseload electricity generation by load-serving entities. (Applies to in-state or imported electricity.)	Ensures no reduction in energy supply reliability Emissions based on net emissions from electricity production. CO_2 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[35]	July 1, 2008	Equal to or less than 1100 lbs of CO_2e/MWh	New, long-term financial commitments to baseload electricity generation by IOU and consumer-owned utilities.	Ensures no reduction in energy supply reliability. Emissions based on net emissions from electricity production. CO_2 stored in geologic formations shall not be counted as emissions from the power plant.
Carbon Dioxide Emission Standards For *New* Energy Facilities – "facility-based"				
Oregon: HB 3283[36]	1997 Updated 2003	Meet emissions standard 17% better than the most efficient base-load gas plant currently operating in the U.S. (0.675 lb. CO_2 per kWh)	New energy facilities.	Compliance options: • implement offset projects directly • pay a fee of $0.85 per metric ton CO_2 using a qualified organization that purchases/manages offsets (below market cost of offsets).
Washington: HB 3141 & RCW 80.70.020, WAC 173-407	2003 Updated 2004	CO_2 mitigation plan to offset 20% of CO_2 equivalent emissions over a 30 year period	New energy facilities > 350 MW (EFSEC rules); 25-350 MW (Dept Ecology rules); or output increases at existing facilities	Compliance options: • implement offset projects directly • pay a fee of $1.60 per metric ton CO_2 using a qualified organization that purchases/manages offsets (below market cost of offsets).
Carbon Dioxide Emission Standards For *Existing* Energy Facilities—"facility-based"				
Massachusetts: Amendment to 310 CMR 7.29[37]	2006 cap 2008 rate	Cap: Emissions cannot exceed historical emissions Rate: Emissions must not exceed 1800 lb CO_2/MWh	Six current power generation facilities in MA.	Compliance may be met via emission reductions, avoided emissions, or sequestered emissions.

[33] http://www.energy.ca.gov/ghgstandards/documents/sb_1368_bill_20060929_chaptered.pdf
[34] http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/64072.htm
[35] http://www.leg.wa.gov/pub/billinfo/2007-08/Pdf/Bills/Senate%20Passed%20Legislature/6001-S.PL.pdf
[36] http://www.oregon.gov/ENERGY/SITING/docs/ccnewst.pdf ;
[37] http://trinityconsultants.com/State_Regulatory_News.asp?st=MA&n=313; http://www.mass.gov/dep/air/laws/ghgappb.pdf

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, combined-cycle natural gas power plant.
- Ensures no reduction in energy supply reliability.
- Is based on net emissions from electricity production.
- Does not count CO_2 stored in geologic formations as emissions from the power plant.
- 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 legislature adopted House Bill 25, which repealed most of what remained of Montana's deregulation law. It also authorized NorthWestern Energy (NWE) to invest in new power generation facilities, with certain limitations. It 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 Public Service Commission, 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 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_2: A GPS program would directly target reductions CO_2 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 (MMtCO2e)* 2010	2020	Cumulative Reductions (2007–2020)	NPV (2007–2020) $ Millions	Cost-Effective-ness $/tCO2
ES-10	Generation Performance Standard	Reference Case–Compliance Mix	0.1	0.8	4.7	$60	$13
Range of results depending on compliance option							
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_2 emissions of compliance with the GHG Emission Performance Standard, as defined above with the costs and CO_2 emissions of reference case resources. It involves the following steps: (1) estimate the amount of new generation expected to be needed by load serving entities 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; 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 load-serving entities (LSE). 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 either: a) load growth; b) plant retirement or derating; c) the lapse of existing contract 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 affect by this rule. On the 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) above. 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: a) natural gas CC plants; b) coal with CCSR; or, c) 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 (levelized c/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 Energy Information Administration *Annual Energy Outlook 2006/7*.[38]

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

Alternative Resource	Busbar Cost ($/MWh)	Emissions Rate ($lbCO_2$/MWh)	Incremental Emission Savings (relative to PC coal)
Natural Gas	$60	782	58%
Renewable Mix	$41–$68	0	100%
Coal CCSR	($30/$tCO_2$)	1100	40%

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.

[38] http://www.westgov.org/wieb/electric/Transmission%20Protocol/SSG-WI/pnw_5pp_02.pdf

ES-11. Methane and CO_2 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_4) and CO_2 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.

The EPA 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, among others.

There are a number of ways in which CO_2 emissions in the oil and gas industry can be reduced by improving energy efficiency, including: (1) new efficient compressors, (2) optimize gas flow to improve compressor efficiency, (3) improve performance of compressor cylinder ends, (4) capture compressor waste heat, (5) replace compressor driver engines, and (6) waste heat recovery boilers.

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

Policy Design

This 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 Gas STAR program. The 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 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: MT DEQ, BLM, USFS, Dept of State Lands, Montana Petroleum Association, Society of Petroleum Engineers, oil and gas companies.

Other: None cited.

Implementation Mechanisms

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

DEQ, 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 USEPA, which currently includes several Montana natural gas companies, encouraging 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 partners sign a Memorandum of Understanding (MOU) wherein they agree to evaluate the Program's recommended Best Management Practices (BMPs) for reducing methane emissions and implement them when 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_2: CO_2 emissions would be reduced directly through the fuel use and flaring reductions.
- CH_4: Methane emissions would also be reduced, mostly through decreased venting and leak reductions.

Estimated GHG Savings and Costs Per Ton

			Reductions		($MMtCO_2e$)		
	Policy	**Scenario**	**2010**	**2020**	**Cumulative Reductions (2007–2020)**	**NPV (2007–2020) $ Millions**	**Cost-Effective-ness $/tCO_2$**
ES-11	CH_4/CO_2 Reduction in Oil & Gas Industry	Reference Case	0.1	0.5	3.9	No yet estimated	Likely net benefit
ES-11	CH_4/CO_2 Reduction in Oil & Gas Industry	High Fossil Case	0.3	0.8	6.6	No 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 website, http://www.epa.gov/gasstar/techprac.htm#tabnav

- o Natural Gas Systems, 1999. U.S. EPA. http://www.epa.gov/methane/reports/03-naturalgas.pdf
- o Addendum to the U.S. Methane Emissions 1990–2020: 2001 Update for Inventories, Projections, and Opportunities for Reductions. U.S. EPA. http://www.epa.gov/methane/reports/2001update.pdf
- o Emissions estimates are from the Montana Inventory and Forecast (see Web sites), per below:

Table G-9. Methane and carbon dioxide emissions estimates, 2005–2020. [AU: This table needs a callout somewhere in the text above.]

Methane Emissions) - MMtCO2e

		Ref Case	High Fossil
	2005	2020	2020
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
Trans & Dist	n/a	n/a	n/a

CO2 Emissions (combustion) - MMtCO2e

		Ref Case	High Fossil
	2005	2020	2020
Natural Gas Industry			
Production	0.11	0.11	0.12
Processing	n/a	n/a	n/a
Trans & Dist	0.15	0.28	0.28
Oil Industry			
Production	included in industrial sector		
Refining	2.44	2.44	4.12

- **Quantification Methods:** GHG reductions would be based on a specified goal level if/as 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 USEPA reports noted above. See also the additional information at the end of this section as provided by USEPA Gas STAR program.
- **Key Assumptions:**
  - o **Cost and emissions savings (natural gas industry methane emissions)—**As indicated in the national analysis shown in USEPA, 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	2005		2010		2015		2020	
Baseline Emissions (MMTCE)	36.5		37.4		38.5		39.8	
	Reductions		Reductions		Reductions		Reductions	
Carbon Value $/TCE	Cumulative	%	Cumulative	%	Cumulative	%	Cumulative	%
($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%
Remaining Emissions	18.2	50%	18.6	50%	19.0	49%	19.6	49%

Source: USEPA, 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 & 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	
Total		33.5 MMTCE or 5.8 Tg		1.6 MMTCE or 0.27 Tg

Totals may not sum due to independent rounding.
Source: EPA, 1999.

Source: USEPA, 2000

The following additional information was provided by USEPA Gas STAR program representatives:

- **Cost curves for methane emissions reduction from oil and gas systems in Montana (\$/tC0_2)—**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/excel/techtbls.xls). The referenced link contains access to an Excel document with many reduction technologies and their respective reduction efficiencies, U.S.-based capital and operation/maintenance costs. There is also additional data in a recent EPA report entitled "Global Mitigation of Non-CO_2 Greenhouse Gases" (EPA Report 430-R-06-005, http://www.epa.gov/nonco2/econ-inv/international.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 in the July 12th, 2004 (http://www.epa.gov/gasstar/news/interops.htm). The article shows that approximately 60% of methane emissions can be mitigated for less than 10 dollars per tonne of CO_2 equivalent (\$10/tCO_2).
- **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—**Natural Gas STAR 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/techprac.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:

- Optimize glycol circulation and install of flash tank separators in dehydrators
- Install electric pumps on dehydrators
- Install 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_4 and CO_2 emissions can be reduced in the production of liquid fuels at oil refineries or coal-to-liquids plants. These options include various efficiency measures including enhanced combined heat and power along with carbon capture and storage.

Coal-to-liquids (CTL) plants are energy-intensive and emit 10 times more CO_2 than conventional oil refineries in order to produce liquid fuels.[39] Emissions reductions from CTL production can be achieved through polygeneration, biomass blending, and most significantly through carbon capture and storage. CTL fuels production is especially amenable to carbon dioxide 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_2 before entering the Fischer-Tropsch reactor.[40] 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 greenhouse gas 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. This could imply that:

- CTL facilities would capture and store CO_2 from the start of operations, assuming this technology is considered commercially available. CTL facilities would have to essentially eliminate their CO2 emissions in the coal to liquids production process in order to meet the goal of 20-30% reduction in lifecycle emissions.
- In order for fuel produced through a CTL process to achieve a 20% to 30% reduction of lifecycle emissions relative to petroleum-based fuels, it is also necessary for the fuel produced from a CTL plant to have lower carbon-intensity than petroleum-based fuels. This could be achieved through co-firing a large fraction of biomass.
- 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).

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[39] 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.

[40] Brandt, A. R. and A.E. Farrell (2006) Scraping the Bottom of the Barrel: CO2 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

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

Timing: Under development.

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 coal-to-liquids refineries.

Type(s) of GHG Benefit(s)

- CO_2: CO_2 emissions would be reduced directly through fuel use reductions
- CH_4: CH_4 could also be reduced due to process changes (e.g., leak reductions, as appropriate)

Estimated GHG Savings and Costs Per Ton

	Policy	Scenario	Reductions (MMtCO$_2$e)			NPV (2007–2020) $ Millions	Cost-Effective-ness $/tCO$_2$
			2010	2020	Cumulative Reductions (2007–2020)		
ES-12a	CTL Production	**High Fossil Case** Coal-to-Liquids—High Fossil Fuel Case: 20–30% lower life cycle emissions than diesel (via CCS, biomass co-firing, poly-generation)	0	9.9	35	Not est.	Not est.
ES-12b	Petroleum Refining	**Reference Case**	0.02	0.24	1.5	Not est.	Not est.
		High Fossil Case	0.03	0.38	2.2	Not est.	Not est.

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

ES-12a—Coal-to-Liquid Production:

- **Data Sources:**
  - Williams, R. H., 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

o 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, 27 January 2005 (Figure G-2). http://www.mtclimatechange.us/ewebeditpro/items/O127F10781.pdf

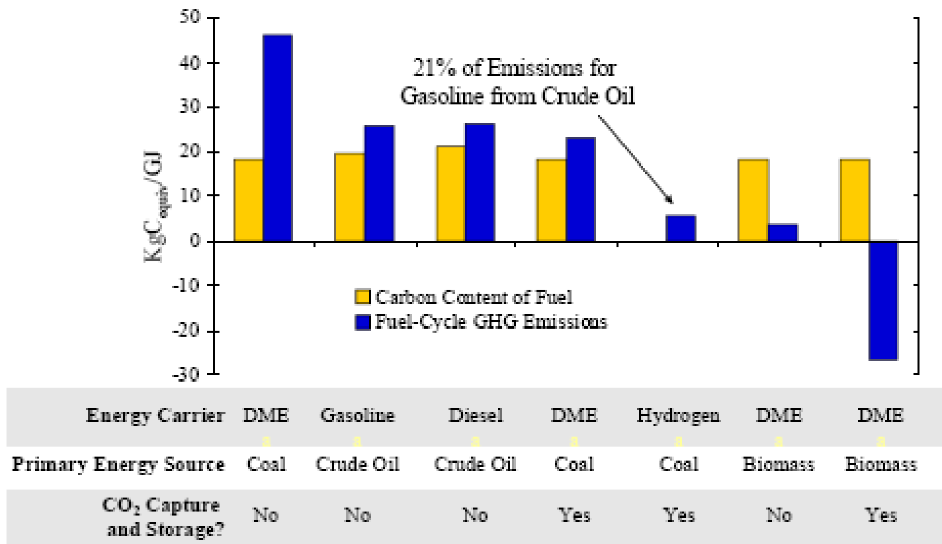
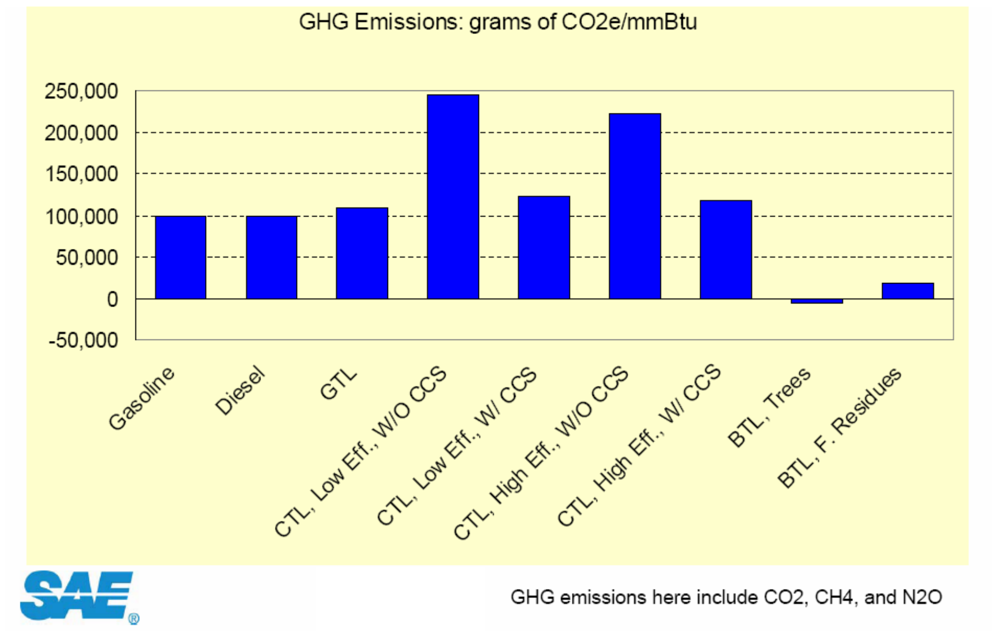


Figure G-2. Fuel C content, fuel-cycle GHG emissions for a limited sample of fuels/primary energy sources.

o Williams, R.H., 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/dclversussicl.pdf

o Wang, M., 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).



Source: Wang et al, 2007 (BTL = biomass-to-liquids; CCS not considered for BTL in this study)

Figure G-3. Greenhouse gas emissions per million Btu of fuel produced and used.

- o Brandt, A. R. and A.E. Farrell (2006) Scraping the Bottom of the Barrel: CO_2 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

- **Quantification Methods:** Given the large uncertainties and variation among technologies that might be employed for coal-to-liquids 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_2 emissions would be captured and stored.

Table G-12. Comparison of Coal to Liquid Production

	Life-Cycle Emissions Relative to Petroleum Product (Diesel)	Upstream* GHG Emissions in 2020 ($MMtCO_2e$)	GHG Emission Reductions in 2020 ($MMtCO_2e$)
CTL Production, no capture and storage	2.25	13.7	–
CTL Production (as in high fossil projection, with 30% capture and storage)	1.73**	7.3	–
CTL Production with Full Carbon Capture and Storage (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 fraction co-fired)	–	5 to 17
ES-12a goal: 20–30% lower emissions than petroleum products	0.75 (midpoint)	–2.6	9.9

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_2 emissions from coal use at the CTL plant only.

- **Key Assumptions:** See above.

ES-12b: Petroleum Refining

- **Data Sources:** USEPA, 2007. Energy Trends in Selected Manufacturing Sectors: Opportunities and Challenges for Environmentally Preferable Energy Outcomes[41]
- **Quantification Methods:** USEPA (2007) estimates that energy intensity in the petroleum refinery industry could decline by 0.9% per year in an advanced energy scenario, based on USDOE's Scenarios for a Clean Energy Future study, which modeled a policy implementation pathway via voluntary energy efficiency commitments.[42] The USDOE and USEPA studies do not estimate cost impacts for individual sectors; the overall savings across the entire US economy is projected at $80 billion in 2020 though the USDOE 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. (As the USEPA 2007 study notes, "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.")

[41] http://www.resourcesaver.org/file/toolmanager/CustomO16C45F77356.pdf
[42] http://www.ornl.gov/sci/eere/cef/CEFCh5.pdf

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.

Table 54: 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	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.[282] 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).[283] 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.[284] 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.[285]
Equipment retrofit/ replacement	Medium	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.[286] Opportunities lie with furnaces, heat exchange equipment (replacement with helical, vertical heat exchangers), sensors and controls, equipment used in separation processes, and containment vessels.[287] 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). 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."[288] To avoid NSR, refineries may find it easier to retrofit existing equipment as opposed to installing the latest energy-efficient technologies.
Process improvement	Medium	The most energy-intensive processes in petroleum refining include distillation (atmospheric and vacuum), hydrotreating, alkylation, and reforming.[289] 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.[290] 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. 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.[291]
R&D	Medium	API notes the following R&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.[292] Promising technologies are currently in development, such as membrane separation technologies that increase the efficiency of distillation units by 20 percent. Under Climate VISION, the R&D Challenge focuses on technologies that reduce/sequester carbon emissions.[293] The industry has developed mission statements and roadmaps for crucial R&D priority efforts as part of its efforts with DOE/IOF; see http://www.eere.energy.gov/industry/petroleum_refining/. 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&D and other large-scale improvements. 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.[294]

ES-13 CO_2 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 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[1]	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_2 Natural gas: $11.26 per ton CO_2	1990 Fuels 1997 Electricity consumption not fuels Reduced for industry Exemption for international aviation, shipping, and refineries	Reimbursement via lower payroll taxes
Norway[2]	1991 Revised 1999	Petrol: $55.90 per ton CO_2 Mineral Oil: $30.16 per ton CO_2 Oil and gas in North Sea: $52.05 per ton CO_2	Producers and importers of oil products Exemption for foreign shipping, fishing, external aviation	Reduce other taxes
Sweden[3]	1991 Revised 2004	CO_2: $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[4]	1992 Revised 1999	Commercial $14.30 per ton CO_2 Households $7.15 per ton CO_2	Buildings	Reallocated as subsidies for energy efficiency activities and voluntary agreements

Jurisdiction	Status: Start Date	Tax Rate–Applicability	Where Tax Applied	Use of Revenue
Germany[5]	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[6]	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

Jurisdiction	Status: Start Date	Tax Rate–Applicability	Where Tax Applied	Use of Revenue
Australia: State of West Australia[7]	Under current consideration	\$19.58 per ton CO_2		
Canada: Province of Quebec[8]	2006	To be determined by Quebec Energy Board \$1 billion est. 6-yr revenue	Non-renewable fossil fuels sold in bulk to retailers	Green Fund: Public transportation, energy efficiency for buildings

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

2 http://www.regjeringen.no/en/ministries/fin/Selected

3 http://pubs.acs.org/hotartcl/est/98/dec/hanis

4 http://www.norden.org/pub/ebook/2001-566.pdf ; http://www.iea.org/textbase/pamsdb/detail.aspx

5 http://www.iea.org/textbase/pamsdb/detail.aspx?

6 http://www.iea.org/textbase/pamsdb/detail.aspx?mode=cc

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

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