



## Energy Supply Policy Work Group

### Summary List of Draft Priorities for Analysis

	Policy Option	GHG Reductions (MMtCO <sub>2</sub> e)			Net Present Value in 2007 2007-2020 (Million \$2005)	Cost-Effectiveness (\$2007/tCO <sub>2</sub> e)	Level of CAP Support
		2012	2020	Total 2007-2020			
ES-1	Renewable Energy Incentives Including Waste to Energy	Benefits are quantified in policy ES-2.					TBD
ES-2	Mandated Portfolio Standards	3	8	58	\$784	\$14	TBD
ES-2a	Clean Energy Portfolio Standard	Non-specific policy was not quantified					TBD
ES-3	Transmission Infrastructure for Renewables	Non-quantitative policy proposal analyzed					TBD
ES-4	Cost for CO <sub>2</sub> Emissions (Cap and Trade or Tax)	Non-specific policy not quantified					TBD
ES-5	Public Benefit Charge Funds	Quantitative analysis pending					TBD
ES-6	Incentives for CHP, DG, Smart Grid	0.4	1	7	\$230	\$32	TBD
ES-7	Carbon Capture & Transport Infrastructure	Non-quantitative proposal not quantified					TBD
ES-8	Pricing and Rates	Covered in RCI-7, "Pricing and Purchasing"					
ES-9	R&D for Carbon Emissions Reducing Generating Technology	R&D benefits not quantified					TBD
ES-10	Promote Advanced Fossil Fuel Generation with Carbon Capture, Including IGCC	Non-specific policy not quantified					TBD
ES-11	Small New Hydro and Efficiency Improvements at Existing Hydro, Identifying Other Small Renewables and Removing Barriers Thereto	0	0.8	3	\$123	\$40	TBD
ES-12	Nuclear Energy	Non-specific policy not quantified					TBD

	Policy Option	GHG Reductions (MMtCO <sub>2</sub> e)			Net Present Value in 2007 2007–2020 (Million \$2005)	Cost-Effectiveness (\$2007/tCO <sub>2</sub> e)	Level of CAP Support
		2012	2020	Total 2007-2020			
ES-13	Efficiency Improvements for Existing Generators (Includes Heat Recovery)	Quantitative analysis pending					TBD
ES-14	Oil and Gas Operations	0.8	3	16	\$12	\$0.8	TBD
ES-15	CO <sub>2</sub> Emission Standards for Power Plants	0.5	2	13	\$14	\$1	TBD
	<b>SECTOR TOTAL AFTER ADJUSTING FOR OVERLAPS</b>	4	9	61	846	14	
	<b>REDUCTIONS FROM RECENT ACTIONS (table to be added below)</b>	-	-	-	-	-	
	<b>SECTOR TOTAL PLUS RECENT ACTIONS</b>	4	9	61	846	14	

## ES-1. Renewable Energy Incentives

### Policy Option Description

Resource maps of renewable energy in Colorado developed by the Department of Energy's National Renewable Energy Laboratories (NREL), based in Golden, CO, show that Colorado is well-endowed with renewable resources. Wind is prevalent in the northeast and southeast corners of the state. Biomass is available in the northeast. Photovoltaics can be deployed throughout the state. Concentrating solar power can be tapped in the San Luis Valley. Deep geothermal resources exist in the southern portion of the state. Solar and wind alone may have the potential to produce 100 times the electricity currently used in Colorado, even after reasonable filters are applied. However, renewables are generally more costly than today's conventional energy supplies. Financial incentives can greatly accelerate the deployment of renewables and allow time for learning curves, economies of scale, and R&D to lower their costs.

Mechanisms include an investment tax credit, an energy production tax credit, a tax incentives, and incentives to help support financing of projects. Production tax credits are generally preferred by renewable energy providers that can produce electricity at under about 10 cents per kWh (wind and geothermal), whereas investment tax credits are generally preferred for more expensive technologies (concentrating solar power). Key to the success of these incentives is that they be guaranteed for a period of at least 5 years to allow time to raise financing and build projects.

Financial incentives that encourage utilities to deploy or purchase renewable energy should also be considered. Finally, R&D aimed at solving Colorado-specific issues can be funded at state universities and NREL. These issues include resource assessment and performance-cost analysis.

### Policy Option Design

**Goal:** Financing and/or tax incentives to meet goals in ES-2

**Timing:** 2009

**Coverage:** First 2000 MW capacity in state

**Other:** Not applicable.

### Implementation Mechanisms

SBC or other funds are distributed as investment tax credits, production tax credits and/or other financial incentives.

### Related Policies/Programs in Place

Federal production tax credit for wind energy and investment tax credit for PV systems.

### Type(s) of GHG Reductions

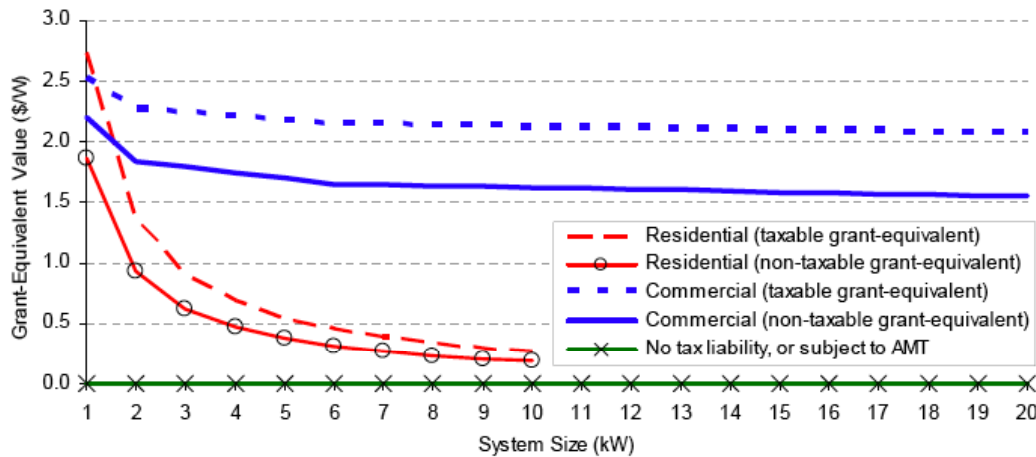
Decreased fossil generation resulting from replacement with renewable generation.

**Estimated GHG Savings and Costs per MtCO<sub>2</sub>e**

Benefits are quantified in companion policy ES-2.

We found one attempt specifically to quantify the benefits of investment incentives – in the report, *Exploring the Economic Value of EPCAct’s PV Tax Credits* by Bolinger, et al. In this report, the authors use a cash-flow model to calculate the “grant-equivalent benefit” to PV owners of the EPCAct 2005 investment tax credit for PV. As seen in their chart (below), they find the benefit to be equivalent to grants in the range of \$1.75 to \$2.75 per Watt for very small systems. The value falls rapidly with increasing system size for residential owners, but much less rapidly for commercial owners. (Graphic taken from Bolinger, Wisner and Ing, page 8.)

**The Benefits of the EPCAct Tax Credit for PV Owners**



**Data Sources:**

Bolinger, Wisner and Ing, *Exploring the Economic Value of EPCAct’s PV Tax Credits*, Lawrence Berkeley National Laboratory, February, 2007.

Cameron Brooks, et. al., *A Guidance Document on Debt and Equity Investment Mechanisms for the Clean Energy States Alliance*, November, 2003.

Brooks, Milford and Schumacher, *Global Clean Energy Markets: the Strategic Role of Public Investment and Innovation*, a report for the Clean Energy Group, May 2004.

**Quantification Methods:**

Quantified with companion policy proposal ES-2.

**Key Assumptions**

**Key Uncertainties**

**Additional Benefits and Costs**

TBD

**Feasibility Issues**

TBD

**Status of Group Approval**

TBD

**Level of Group Support**

TBD

## ES-2. Mandated Portfolio Standards

### Policy Option 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 kWh that a utility supplies, 5 kWh must be generated from renewable resources. About 20 states currently have an RPS, including Colorado. Colorado's current RPS requires investor-owned utilities to provide 20% renewable energy by 2020 and other load serving entities to provide 10%, also by 2020. In some states, utilities can also meet their RPS (or EPS) by purchasing certificates from eligible energy projects, typically referred to as Renewable Energy Certificates (RECs).

### Policy Option Design

**Goal:** 30% of total energy to come from renewables; no more than 85% of this from "big wind."

**Timing:** by 2020

**Coverage:** All retail electric suppliers, including municipally owned and co-ops.

### Implementation Mechanisms

Mandate applicable to all IOUs, munis and coops

### Related Policies/Programs in Place

The existing RPS in Colorado requires 20% renewables for IOUs and 10% renewables for cooperatives and municipal utilities (with +40,000 customers) by 2020. IOUs must meet 4% of their annual target with solar, half of which must be located on-site at customers' facilities

In-state renewable resources receive favorable treatment. Each kilowatt-hour (kWh) from eligible in-state renewable projects receives 125% credit for RPS-compliance purposes. Certain community-based project can receive 150% credit under cooperatives and eligible municipal utilities, and solar projects online by 2015 receive 300% credit.

Utilities are entitled to recover prudent cost of complying RPS through retail rates. Utilities may comply with the RPS by purchasing RECs.

### Type(s) of GHG Reductions

Reductions come from reduced fossil-fueled generation relative to the reference case.

**Estimated GHG Savings and Costs per MtCO<sub>2</sub>e**

	Policy Option	GHG Reductions (MMtCO <sub>2</sub> e)			Net Present Value 2007–2020 (Million \$)	Cost-Effectiveness (\$/tCO <sub>2</sub> e)
		2012	2020	Total 2007- 2020		
ES - 2	Mandated Portfolio Standards	3	8	58	\$784	\$14

Note also that costs shown include only the projected costs of the renewable energy and avoided cost of displaced generation; we have not included any administrative costs.

**Data Sources:**

Data from the following sources were used in this analysis.

Black and Veatch; research performed for the U.S. Department of Energy, National Renewable Energy Laboratory and American Wind Energy Association, unpublished draft report.

Colorado Springs Utilities, unpublished research on biomass fuel and technology costs in Colorado.

KEMA 2006. Colorado DSM Market Potential Assessment, March 31, 2006.

National Renewable Energy Laboratory, Comparison of Cost-Based U.S. Operational Impact Studies [Date ?].

Synapse Energy Economics and Tellus Institute, A Balanced Energy Plan for the Interior West, a report for Western Resource Advocates, 2004. Available at: [www.westernresourceadvocates.org](http://www.westernresourceadvocates.org).

US EIA, Annual Energy Outlook 2007, Assumptions to the AEO, Electricity Market Module. Available at: <http://www.eia.doe.gov/oiaf/aeo/assumption/index.html>.

Wiser and Bolinger, Report Summary, Annual Report on U.S. Windpower Installation, Cost and Performance Trends, 2006, U.S. Department of Energy May 2007.

Wiser, et. al., Letting the Sun Shine on Solar Costs: An Empirical Investigation of Photovoltaic Cost Trends in California, LBL, January, 2006, LBNL-59282.

**Quantification Methods:**

The PWG working group provided the following guidelines:

- Large wind projects could not account for more than 85% of the renewable energy requirement,
- Each of the following resources provides three percent of the renewable energy requirement: solar thermal, small scale solar PV, small hydro, biomass and geothermal.

We first reviewed a number of sources to develop cost assumptions for each of the eligible renewable technologies over the study period. We next calculated the amount of each type of new renewable technology needed to meet the policy goal in 2020, and interpolated the growth of each technology from current levels to the 2020 levels. (See discussion of this below.) We balanced supply and demand in each year by backing off coal- and gas-fired generation in a ratio

of 75% coal and 25% gas. We first backed off any fossil generation added in that year, and when new generation reached zero, we began backing off generation from existing fossil units.<sup>1</sup> Generation from existing coal-fired plants was reduced by 2% in 2008 and 6% in 2020. Generation from existing gas-fired plants was reduced by 2% in 2008 and 7% in 2020. As a final step we calculated avoided GHG emissions as a result of the decreased fossil fuel generation.

We calculated the cost of the RPS by calculating total costs for each technology in each year. When the cost of a technology changed over time, previously installed capacity continued to operate at its original levelized cost, while new capacity from that point forward used the updated levelized cost. The total cost of the new renewable energy was then summed for each year and compared to the total avoided cost, calculated with an real avoided cost figure of \$56 per MWh throughout the study period. This avoided cost figure is based on from Xcel’s 2006 DSM market assessment.

**Key Assumptions**

The required mix of generating technologies fundamentally drives the cost of this option. A similar RPS program with technological diversity requirements would have significantly lower costs.

Major assumptions affecting this analysis are:

- the mix of renewable technologies meeting the RPS;
- the cost of these technologies;
- the avoided cost of fossil fuel generation; and
- the type of generation displaced by new renewable generation.

The percentage of total RPS energy generated from each renewable technology is shown in the table below along with total renewable generation. The figures for 2007 are based on projected 2007 generation from existing renewable facilities, and the RPS is assumed to take effect in 2008. We assume that 10% of existing hydro generation is eligible to meet the RPS.

**Assumed Mix of Generation Meeting the RPS**

	<b>2007</b>	<b>2010</b>	<b>2015</b>	<b>2020</b>
Wind	83%	91%	88%	85%
Solar PV	0%	1%	3%	3%
Solar Thermal	1%	1%	3%	3%
Existing Hydro	13%	3%	1%	1%
New Hydro	0%	0%	1%	2%
Biomass Co-firing	0%	2%	2%	2%
Other Biomass	3%	1%	1%	1%
Geothermal	0%	0%	2%	3%
Total RPS GWh	1,036	4,395	12,254	20,215

*Percentages may not sum to 100 due to rounding.*

The levelized cost of each technology over the study period is shown in the table below along with relevant sources. Note that the wind costs used are reported net of the federal production tax

<sup>1</sup> Generation from existing coal-fired plants was reduced by 2% in 2008 and 6% in 2020. Generation from existing gas-fired plants was reduced by 2% in 2008 and 7% in 2020.

credit. That is, the cost shown in the table is the contract price at which the wind owners are expected to sell energy, assuming receipt of a tax credit worth \$18 to \$20 per MWh output. The assumption that the production tax credit is extended through the study period is implicit in this analysis.

**Assumed Levelized Cost of Renewable Technologies (2005\$/MWh)**

	2010	2015	2020	Relevant Sources
Wind	50	45	45	Wiser and Bolinger; Black and Veatch
Solar PV	576	409	409	Synapse; Wiser, et. al.
Solar Thermal	254	243	243	Synapse; EIA
Small Hydro	---	105	105	PWG assumption.
Biomass Co-firing	20	20	20	Colorado Springs; Synapse
Other Biomass	67	67	65	Colorado Springs; Synapse
Geothermal	---	78	74	Scaled up from EIA; Black and Veatch

The wind costs are based largely on market price data for recent wind project as reported in Wiser and Bolinger. These costs were compared to a number of other estimates, most notably the data recently developed by Black and Veach for DOE, NREL and AWEA. Current costs are high based on high demand for equipment. We assume that higher costs persist through 2010 and that costs fall to recent historical levels (\$45) after that. (This assumption was not supported by all PWG members.)

The PV costs used are consistent with residential scale PV systems – in the range of 2 kW in size. Capital costs are assumed to be \$8,490/kW in 2008 falling to \$6,000/kW in 2020. The capital recovery factor (11.7%) is lower than for other technologies due to the small scale at which PV is installed. Capacity factor is assumed to be 20%.

Small hydro is assumed to cost \$3,000/kW with total O&M costs of \$5.00/MWh. Capacity factor is 35%. Projects are depreciated over 40 years; capital recovery factor is 10.2%

Biomass co-firing costs are estimated to range from \$15 to \$25 per MWh depending on fuel costs and whether or not fuel handling equipment is purchased. Fuel costs are the key driver of costs and they appear to vary widely – from around \$1.00/mmBtu to over \$2.00/mmBtu. We assume \$20/MWh throughout the study period.

Other biomass energy is assumed to be provided by fluidized bed plants with capital costs of \$2,400/kW, total O&M of \$28.50/MWh. The assumed capital recovery factor is 12.6%. Capital costs are assumed to fall 5% by 2015 due to technology development and learning.

This geothermal cost estimate here is highly speculative. We found very little data on the cost of developing deep geothermal resources such as those in Colorado. We have taken the EIA’s estimate for developing shallow resources and scaled it up to account for the depth and untested nature of the CO resource. EIA's capital cost is \$2,260/kW: we assume capital costs of \$4,000/kW and use EIA's O&M cost of \$77/kW-yr. Capital costs are assumed to fall 5% in 2020 due to technology development and learning.

In addition to these costs, we added system integration costs to wind energy. These costs rise as wind generation becomes a larger portion of total, as shown in the table below. These assumed costs are based on an NREL review of wind integration cost studies.

**Assumed Wind Integration Costs (2005\$)**

Penetration (% energy)	0-5%	6-10%	11-15%	16-20%	21-25%
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Cost (\$/MWh)                      0                      1                      2                      3                      5

**Key Uncertainties**

In terms of emissions, the key uncertainty is what fuels are backed off as new renewable generation is added to the system. We have assumed that both new plant additions are deferred and existing plants are utilized less in the ratio of 75% coal and 25% gas. In reality, each new resource type will affect the system differently, based on its pattern of generation, and the dynamics differ significantly in the short run and the long run. Further, the ability of new renewable resources to meet peak load requirements in the state must be assessed.

Hourly dispatch modeling might help to shed more light on these dynamics in this study.

In terms of cost, the costs assumed for wind energy and the avoided cost have the largest impact on estimated RPS costs.

Wind integration costs are highly variable and system-specific.

**Additional Benefits and Costs**

Transmission costs for serving wind resources are not included in this analysis. (See discussion in ES-3.)

**Feasibility Issues**

Current RPS requirement for munis and coops is lower than for IOUs—10% by 2020. This policy may be especially burdensome for these entities.

Ability to meet peak demand requirements with variable output renewable resources.

**Status of Group Approval**

TBD

**Level of Group Support**

TBD

**Barriers to Consensus**

Some PWG members objected to aggressive standard as potentially not feasible, and suggested the state should gain experience with the current 20% standard before mandating a more aggressive one.

Members also objected to the result that new capacity was not needed on the grounds that it may be needed for reliability purposes even if not for energy.

## ES-2a. Clean Energy Portfolio Standards

### Policy Option Description

This is a variant on the portfolio standard that is more broadly defined to include energy efficiency, clean coal, new nuclear resources, and carbon offsets, as well as renewable energy, and is based on a proposal by Xcel energy for a nationwide portfolio standard. Xcel's analysis and that of EIA can provide insight into the potential of a Colorado-only program.

### Policy Option Design

**Goal:** Implement Xcel's proposed "clear energy portfolio standard" in Colorado

**Timing:** Not specified

**Coverage:** Not specified

### Implementation Mechanisms

Implementation following Xcel proposal

### Related Policies/Programs in Place

RPS program in Colorado

### Type(s) of GHG Reductions

Avoided emissions based on displaced conventional fossil fuel generation.

### Estimated GHG Savings and Costs per MtCO<sub>2e</sub>

Non-specific policy was not quantified

### Data Sources:

EIA, ICF

### Quantification Methods:

Not Quantified.

### Key Assumptions

- National analysis can be reasonably scaled to Colorado
- Other assumptions as contained in Xcel proposal and/or EIA analysis.

### Key Uncertainties

Uncertainties in the projected costs of new nuclear and IGCC units are substantial.

### Additional Benefits and Costs

TBD

**Feasibility Issues**

TBD

**Status of Group Approval**

TBD

**Level of Group Support**

TBD

**Barriers to Consensus**

TBD

## ES-3. Transmission Infrastructure for Renewables

### Policy Option Description

SB 100 provides that utilities regulated by the Public Utilities Commission are required to file maps of generation resource areas that need transmission, and transmission plans to serve those areas, for approval by the PUC by October 31 of each odd-numbered year. This new law changes the goal of transmission planning and investments by requiring planning and investment for transmission to serve resource areas, rather than for single generators as had been the case in the past. This will break the “chicken and egg” dilemma for new renewable energy projects in the state, where transmission to serve potential wind-power resources could not be built without generators to serve, but no wind project developer could develop a project in an area without transmission already in place.

The mitigation option proposed here is to expand the coverage of SB 100 to all Colorado utilities to achieve a seamless, coordinated transmission network solution to support renewable resources statewide, instead of limiting transmission planning to areas served by investor owned and PUC regulated utilities.

The proposed solution is to plan for phased expansion based on the magnitude of the wind resource, along with attention to engineering, cost, statewide and regional transmission needs, and benefits associated with transmission investments including consumer savings from adding diverse resources to utility generation portfolios.

As a guide, this proposal includes full implementation of the National Wind Coordinating Collaborative (NWCC) / Western Governors' Association (WGA) Leadership Forum Draft Action Plans: Implementing Transmission Recommendations in the West. Information on these plans can be found on the following websites:

Press release: <http://www.westgov.org/wga/press/plenary1-pr.htm>

Policy resolution: <http://www.westgov.org/wga/policy/06/clean-energy.pdf>

Report: <http://www.westgov.org/wga/meetings/am2006/CDEAC06.pdf>

General website: <http://nationalwind.org/events/transmission/western/2006/default.htm>

### Policy Option Design

**Goal:** Require joint planning and cooperation and to design “expandable” transmission to serve renewable energy resource zones. (providers & RE developers working together.)

**Timing:** Pass legislation amending SB 100 in the 2008 legislative session.

**Coverage:** Statutory changes will directly affect utilities and renewable resource developers regulated by the Public Utilities Commission (PUC). Locally controlled and regulated utilities and federal power marketing agencies will be encouraged to participate.

## Implementation Mechanisms

Requirement on transmission providers as discussed above.

Renewable energy technologies face a barrier to development that conventional fossil-fuel energy technologies do not—namely, many renewable energy technologies (e.g. wind, geothermal) must be built where the energy source is best which is often far from existing transmission lines and load centers. Under current Federal Energy Regulatory Commission (FERC) rules, interconnecting generators, such as new wind farm developers, pay the full cost of the tie-lines from the generator to the first point of interconnection with the grid.<sup>2</sup>

FERC rules also determine who pays for upgrades needed for the transmission grid to serve new renewable energy generators:

Network upgrades are defined as the additions, modifications, and upgrades to the transmission system at or beyond the point of connection to the grid to accommodate generators to the system. The full cost of network upgrades for generator interconnection is borne by and rolled into transmission rates of transmission owners. Transmission owners, however, may require interconnecting generators to provide upfront funding for network upgrades and then credit the funds, with interest, back to generators over time following commercial operation of generators.<sup>3</sup>

Some states—notably Texas, Minnesota, and California—have adopted policies to reduce the transmission barriers to renewable energy development. All three states provide cost recovery incentives for utilities or financing options for smaller power plant owners to facilitate construction of transmission to meet RPS goals. A similar policy would have to be adopted in Colorado before this policy could be cost effective.

## Related Policies/Programs in Place

SB 100

## Type(s) of GHG Reductions

Lower CO<sub>2</sub> emissions associated with displaced fossil fuel-based electricity generation.

## Estimated GHG Savings and Costs per MtCO<sub>2</sub>e

Non-quantitative policy proposal not amenable to analysis.

## Quantification Methods:

N/A

## Key Assumptions

The following sources could be used to support an assumption of between \$1,000 to \$2,000/MW-mile for the cost of transmission infrastructure for renewables:

<sup>2</sup> Western Governors' Association (WGA) Clean and Diversified Energy Initiative. *Draft Report of the Transmission Task Force*. March 2006. Available on the Internet: [tinyurl.com/2cjglk](http://tinyurl.com/2cjglk)

<sup>3</sup> WGA. *Draft Report of the Transmission Task Force*.

For its Wind Deployment System (WinDS) Model, NREL assumes a \$1,000/MW-Mile cost of transmission with scenarios for \$700 and \$1,400/MW-Mile as well. This data is available at: [http://www.nrel.gov/analysis/winds/transmission\\_cost.html](http://www.nrel.gov/analysis/winds/transmission_cost.html).

The report Tackling Climate Change in the US: Potential Carbon Emission Reductions from Energy Efficiency and Renewable Energy by 2030 also uses \$1,000/MW-Mile as the cost assumption for new transmission in its modeling. This report is available at: [http://www.ases.org/climatechange/climate\\_change.pdf](http://www.ases.org/climatechange/climate_change.pdf).

The report by the Western Governors' Association's Geothermal Task Force Report assumes a transmission cost of \$1,000/MW-Mile with an alternate case assumption of \$2,000/MW-Mile. This report is available at: <http://www.westgov.org/wga/initiatives/cdeac/Geothermal-full.pdf>.

The presentation Wind Power in the US to 2030: An Industry Perspective on **in Texas**

The Western Governors' Association's Wind Task Force Report assumes a cost for new transmission of \$1,000/MW-Mile. This report is available at: <http://www.westgov.org/wga/initiatives/cdeac/Wind-full.pdf>.

### **Key Uncertainties**

Location of and cost of providing transmission access to wind resource areas in the state

### **Additional Benefits and Costs**

Ancillary benefits of expanded transmission infrastructure; economic opportunities and employment in CO.

### **Feasibility Issues**

PUC authority to compel all transmission providers to participate, including munis.

### **Status of Group Approval**

TBD

### **Level of Group Support**

TBD

### **Barriers to Consensus**

TBD

## ES-4. Cost for CO<sub>2</sub> Emissions (Cap and Trade or Tax)

### Policy Option Description

Establishing a cost for CO<sub>2</sub> emissions is an alternative, and complementary, GHG-control method relative to direct regulations such as energy efficiency standards. The concept is to internalize the externality, allowing the marketplace find the most efficient reductions. Pricing CO<sub>2</sub> emissions has two primary effects. First, it increases the cost of carbon-based energy to encourage conservation and energy efficiency. Second, it provides an economic advantage to non-carbon-based or lower emissions energy technologies.

There are two basic approaches: cap and trade (C&T) and carbon taxes. The cap and trade approach has largely been based on the success of the C&T system for acid rain in the US. A cap is placed on total GHG emissions, with each unit of emissions represented by a permit that can be traded to find the lowest cost compliance. Typically the caps begin somewhat high (close to current emissions levels) and ratchet down on a pre-determined schedule.

Under the carbon tax approach, the government collects a tax per unit of GHG emissions. The tax collection can be done either upstream (e.g., wellhead, power plant) or downstream (e.g., gas pump, electricity bill). A carbon tax can be designed to be net revenue neutral. That is, the carbon tax revenue collected would be offset dollar-for-dollar by a reduction of some other tax. The revenue offset can be designed to mitigate impact on lower income or vulnerable ratepayers without negating the incentive for conservation.

Hybrid schemes are possible, such as a tax and trade system where an entity facing a large tax liability could offset their taxes through investments in reducing the GHG footprint of another with no or low liability.

### Policy Option Design

**Goal:** Consider applying a price to carbon emissions on a state, regional or national basis.

**Timing:** 2007

**Coverage:** U.S.

### Implementation Mechanisms

TBD.

### Related Policies/Programs in Place

There are currently no mandatory carbon pricing policies affecting Colorado. Colorado consumers can and do participate in voluntary programs such as the Chicago Climate Exchange. (<http://www.chicagoclimatex.com/>)

**Type(s) of GHG Reductions**

Most economically efficient emissions reductions to be identified by marketplace in response to highly focused economic signals.

**Estimated GHG Savings and Costs per MtCO<sub>2</sub>e**

Non-specific policy not quantified. Conduct a literature review of carbon taxes and cap and trade policies implemented or under consideration by other states and regions.

**Data Sources:**

Synapse Energy Economics, “Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning”, Revised as of June, 2006. <http://www.synapse-energy.com/Downloads/SynapsePaper.2006-06.0.Climate-Change-and-Power.A0009.pdf>

Energy Information Administration, Analysis of S. 139, the Climate Stewardship Act of 2003, EIA June 2003, SR/OIAF/2003-02; Energy Information Administration, Analysis of Senate Amendment 2028, the Climate Stewardship Act of 2003, EIA May 2004, SR/OIAF/2004-06

Paltsev, Sergei; Reilly, John M.; Jacoby, Henry D.; Ellerman, A. Denny; Tay, Kok Hou; Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: the McCain-Lieberman Proposal. MIT Joint Program on the Science and Policy of Global Change; Report No. 97; June 2003.

Bailie et al., Analysis of the Climate Stewardship Act, July 2003; Bailie and Dougherty, Analysis of the Climate Stewardship Act Amendment, Tellus Institute, June, 2004. Available at <http://www.tellus.org/energy/publications/McCainLieberman2004.pdf>

Utility resource planning that incorporate carbon prices (e.g. Xcel Energy, Idaho Power, and PacifiCorp)

**Quantification Methods:**

We will review and summarize these policy developments and literature relating to the costs and benefits of cap and trade and carbon tax regulation options in the United States.

There have been numerous federal GHG emission reduction policies proposed in Congress over the past three to four years. There are studies that estimate the impact of some of the federal proposals including price per ton of carbon.

There are also state and regional initiatives such as California’s Global Warming Solutions Act, Regional Greenhouse Gas Initiative (RGGI) in the Northeast, and Western Regional Climate Action Initiative. Further, some utilities are predicting and incorporating carbon prices in their resource planning.

**Key Assumptions**

None.

**Key Uncertainties**

TBD

**Additional Benefits and Costs**

TBD

**Feasibility Issues**

Feasibility of implementing an effective carbon pricing scheme on a single-state basis is in question. Regional or national programs would probably enhance effectiveness without putting state's businesses at a competitive disadvantage.

**Status of Group Approval**

TBD

**Level of Group Support**

TBD

**Barriers to Consensus**

TBD

## ES-5. Public Benefit Charge Funds

### Policy Option Description

A system benefits charge (SBC) is a small monthly fee assessed on utility bills. The money that is collected is used to fund “public benefits,” which typically include low-income weatherization programs, appliance efficiency rebates, renewable energy rebates, energy efficiency programs, and demand-side management programs. More than twenty states currently assess such charges under a variety of names, including system and public benefits charge, wires charge, access charge, universal service charge and distribution charge. The current proposal is focused on using SBC funds to support renewable energy development.

The goal of SBCs, in the context of climate policy, is to accelerate the implementation of cost effective efficiency measures and the deployment of renewable resources. The charge may range from one to five percent of the monthly bill. In Europe, more than 50 municipal utilities collect fees to promote solar energy installations. In Germany, which has adopted a goal of achieving 20% of its electricity from renewable energy, a typical household may pay up to \$15 more each month. In the United States these charges have typically been much smaller.

In Wisconsin, for example, Madison residential customers pay about 10 cents a day, or \$3 per month. Wisconsin’s public benefits charge collects about \$70 million statewide each year. For small business customers, the charge is a maximum of \$6 per month per meter. For more information on the Wisconsin program see [www.focusonenergy.com](http://www.focusonenergy.com)

In Colorado, some utilities already assess SBCs to fund energy efficiency programs, and the proposal is to expand this. Natural gas utilities can also collect such funds, and a bill to require this has been introduced in the Colorado legislature in past sessions.

### Policy Option Design

**Goal:** 4 mills (\$0.004)/kWh charge — about \$40 per capita per yr, or just under \$190 million/yr. Money to be spent on renewable energy resources

**Timing:** 2008

**Coverage:** All retail electric bills.

### Implementation Mechanisms

SBCs can be assessed as a percentage of the monthly bill, or as a fixed monthly fee that varies by customer class. The funds can be managed by the utilities that collect them, by a nonprofit set up to do so, or by a state agency.

A public benefits charge funding renewable energy has a goal very similar to that of a renewable portfolio standard (RPS). Thus, it is important to consider the strengths and weaknesses of these two tools – and ways they might complement one another or result in an inefficient use of resources.

An RPS establishes a target amount of new renewable energy and relies on market forces to determine which specific projects are developed. Projects receive the subsidy retrospectively (i.e., after they begin generating energy), and cost caps are often included to limit RPS costs to ratepayers. With an SBC, funds are collected and distributed, based on project milestones, by a centralized office. The strengths and weaknesses of the two policies are summarized below.

**Conceptual Comparison of RPS and SBC Approaches**

Characteristic	RPS	SBC
Ability to define/control the amount of new renewable energy targeted.	Strength	Weakness
Ability to define/control the cost of the subsidy to ratepayers. Originally, this was seen as a strength of SBC funding, but with the advent of RPS cost caps it is no longer a significant distinction.	---	---
Use of market forces to distribute funds. In SBC programs, bid review and project selection take up a considerable portion of the administrative budget. Further, centralized processes are subject to the abuse of unfair influence or access to decision makers.	Strength	Weakness
Funding certainty. With an RPS the funding level is uncertain until after completion of project. Project developers – and potential lenders and investors – must rely on estimates. With an SBC the developer knows early on how much will be paid at each project milestone	Weakness	Strength
Ability to support pre-commercial technologies and non-cost barriers to renewables.	Weakness	Strength

Based on these strengths and weaknesses, the RPS should target market-ready technologies, while the SBC should target pre-commercial technologies and other market barriers.<sup>4</sup> Experience to date suggests that significant barriers to renewables remain even in the context of an RPS. For example, perceived risks and other dynamics often raise the cost of capital to renewable energy developers considerably. Subsidies targeting the financing stage can play a critical role. (Financial incentives for renewable energy are also discussed under ES-1.)

**Related Policies/Programs in Place**

City of Boulder currently has a Public Benefits Charge in place.

**Type(s) of GHG Reductions**

Reductions would come from displaced fossil-fueled generation.

**Estimated GHG Savings and Costs per MtCO<sub>2</sub>e**

We have not yet quantified the potential impacts of ES-5.

A number of studies focus on SBC implementation issues and the kind of investments states have made (e.g., different types of loans versus equity positions in projects); however few of these studies attempt to quantify the impacts of SBC funding. One useful data point comes from a review of 10 state clean energy funds by Bolinger and Wiser.<sup>5</sup> The table below shows data

<sup>4</sup> There is considerable literature documenting the funding challenges facing technologies past the basic R&D stage but not yet market ready. See for example: Murphy and Edwards, *Bridging the Valley of Death: Transitioning from Public to Private Sector Financing*, National Renewable Energy Laboratory, May 2003, NREL/MP-720-34036.

<sup>5</sup> Bolinger and Wiser, *The Impact of State Clean Energy Fund Support for Utility-Scale Renewable Energy Projects*, Lawrence Berkeley Laboratory, May 2006. Data shown here are taken from Table 1.

from this study on the amount of funding currently committed by each state and the number of MWs represented by recipient projects.

### SBC Funding and Project MW by State

State	Funding (million\$)	MW	\$/kW
CA	190.0	1,227	155
IL	8.4	113	74
MA	32.8	52	631
ME	5.6	19	295
MN	107.7	252	427
NH	2.7	50	54
NJ	14.7	18	817
NY	10.5	50	210
OR	3.8	122	31
PA	21.4	347	62
Total	397.5	2,249	177

From Bolinger and Wisner's data (in the first three columns) we have calculated the cost per kW of new capacity. The ratios range from \$817/kW in New Jersey to \$31 in Oregon. The ratio across all states is \$177/kW. However, these numbers only include funds committed to projects – they do not include administrative costs of the SBC program. Further work would be needed to identify administrative costs in each state and add them to these numbers. Thus \$177/kW dollars appears to be a low boundary of potential SBC impacts.

The analysis of the RPS proposed in ES-2 is a useful reference point in gauging the potential effects of an SBC without an RPS in Colorado. GHG reductions from this policy are estimated to cost \$14/tCO<sub>2e</sub>. However, this comparison ignores administrative costs and program ramp-up periods. As discussed above, the administrative costs of an SBC are likely to be higher than those of an RPS, while program ramp rates are likely to be longer with an SBC than with an RPS.

Finally, note that the cost of either approach will be driven by the assumption about the mix of new renewable technologies built or supported under the policy. To use these numbers as a benchmark one must assume that each would result in the same mix of new renewable energy resources.

#### Data Sources:

Bolinger and Wisner, *The Impact of State Clean Energy Fund Support for Utility-Scale Renewable Energy Projects*, Lawrence Berkeley Laboratory, May 2006.

Bolinger and Wisner, *Utility-Scale Renewable Energy Projects: A Survey of Clean Energy Fund Support*, Lawrence Berkeley Laboratory, 2002, LBNL-496667.

Brooks, et. al., *A Guidance Document on Debt and Equity Investment Mechanisms for the Clean Energy States Alliance*, prepared for the Clean Energy States Alliance, November 2003.

NJ PIRG Law and Policy Center, *Renewables Work: Job Growth from Renewable Energy Development in the Mid-Atlantic*, Spring 2004.

#### Quantification Methods:

Not quantified at this time. Cost is expected to be comparable to ES-2 on a per-ton CO<sub>2e</sub> basis.

**Key Assumptions**

TBD

**Key Uncertainties**

The amount of new renewable capacity and generation produced by a given amount of SBC funding.

**Additional Benefits and Costs**

Several reports have been published investigating the local employment impacts of renewable energy.<sup>6</sup>

**Feasibility Issues**

TBD

**Status of Group Approval**

TBD

**Level of Group Support**

TBD

**Barriers to Consensus**

TBD

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<sup>6</sup> NJ PIRG Law and Policy Center, Renewables Work: Job Growth from Renewable Energy Development in the Mid-Atlantic, Spring 2004.

## ES-6. Incentives for CHP, DG, Smart Grid

### Policy Option Description

Financial incentives for combined heat & power (CHP) and Distributed Generation (DG) can include: (1) direct subsidies for purchasing/selling systems given to the buyer/seller; (2) tax credits or exemptions for purchasing/selling systems given to the buyer/seller; (3) tax credits or exemptions for operating systems; (4) feed-in tariff, which is a direct payment to CHP/DG owners for each kWh of electricity or BTU of heat generated from a qualifying system; and (5) tax credits for each kWh or BTU generated from a qualifying system.

In addition, the availability of net metering would substantially increase the value of certain kinds of DG resources, as any excess energy produced could effectively be sold to the grid at the retail price to offset the cost of purchasing power when additional energy is needed.

Barriers to these resources include inadequate information, institutional barriers, high transaction costs for 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 requirements, high standby rates, and exit fees. The lack of Standard Offer or long-term contracts, payments at avoided cost levels, and lack of recognition of the value of reduced carbon emissions also creates obstacles to widespread implementation.

Policies to remove these barriers include:

- Improved interconnection rules
- Improved pricing and rates policies, including net metering
- Streamlined permitting
- Procurement policies
- Education/outreach

### Policy Option Design

**Goal:** Ramp up CHP/DG to 2% of total fossil fuel generation; ½ CHP and ½ other DG

**Timing:** Achieve 2% by 2020

**Coverage:** Large industrials, commercial, universities, or anyone with a heating or steam load

### Implementation Mechanisms

Unspecified incentives and/or mandates to develop these resources.

### Related Policies/Programs in Place

**Colorado Net Metering Law:**

Colorado has 2 MW capacity limit on system size under its state wide net metering law, which apply to utilities with +40,000 customers. The information is available at

[http://www.dsireusa.org/library/includes/incentivesearch.cfm?Incentive\\_Code=CO26R&Search=TableType&type=Net&CurrentPageID=7&EE=0&RE=1](http://www.dsireusa.org/library/includes/incentivesearch.cfm?Incentive_Code=CO26R&Search=TableType&type=Net&CurrentPageID=7&EE=0&RE=1)

Some municipal utilities also have established their own net metering rules. See <http://www.dsireusa.org/library/includes/statesearch2.cfm?State=CO&back=fintab&CurrentPageID=7&Search=TableState&EE=0&RE=1>

**Type(s) of GHG Reductions**

Improved energy use efficiency associated with expanded use of CHP and increased generation by renewable DG systems which include PV, landfill gas, biomass, and biogas-based DG systems.

**Estimated GHG Savings and Costs per MtCO<sub>2e</sub>**

	Policy Option	GHG Reductions (MMtCO <sub>2e</sub> )			Net Present Value 2007–2020 (Million \$)	Cost-Effectiveness (\$/tCO <sub>2e</sub> )
		2012	2020	Total 2007- 2020		
ES - 6	Incentives for CHP, DG, Smart Grid	0.4	1	7	\$111	\$15

**Data Sources:**

**CHP Technical Potential:**

- **WGA 2006.** Combined Heat and Power White Paper to the Clean and Diversified Energy Initiative of the Western Governors Association, January 2006, available at <http://www.westgov.org/wga/initiatives/cdeac/CHP-full.pdf>. This report estimated 1,578 MW of technical CHP potential in Colorado. The report mentions that the appendix to the report details this analysis. (However, the appendix is not available on their website <http://www.westgov.org/wga/initiatives/cdeac/cdeac-reports.htm#TaskForceReports>).

**Cost and Performance of CHP and DG:**

- **San Diego Regional Energy Office 2007.** “Statewide Self-Generation Incentive Program Data” (updated April 2007, 2.3 MB XLS), available at <http://www.energycenter.org/ContentPage.asp?ContentID=279&SectionID=276&SectionTarget=35>. The database has cost/kW installed data for several DG technologies. It is not clear from the database that those technologies are used for CHP applications.
- **GRI and NREL 2003,** Gas-Fired Distributed Energy Resource Technology Characterizations – Bringing you a prosperous *future where energy is clean, abundant, reliable, and affordable*, available at [http://www.eea-inc.com/dgchp\\_reports/TechCharNREL.pdf](http://www.eea-inc.com/dgchp_reports/TechCharNREL.pdf). This is the most comprehensive report (although it is getting outdated) on cost and performance of gas-fired CHP technologies.

- **Western Resource Advocate 2004.** A Balanced Energy Plan for the Interior West, prepared by Synapse Energy Economics and Tellus Institute, available at <http://www.westernresourceadvocates.org/energy/bep.php>
- **Navigant Consulting 2006.** “Energy Cost Savings Module for customer-sited DG” prepared for the Massachusetts DG Collaborative, available at [http://masstech.org/renewableenergy/public\\_policy/DG/EnergyCostSavingsModule-Jan202006.zip](http://masstech.org/renewableenergy/public_policy/DG/EnergyCostSavingsModule-Jan202006.zip) (5.5 MB zip file)  
This workbook provides cost and performance data for several CHP applications including gas turbines, reciprocating engines and micro-turbines.
- **Colorado Office of Consumer Counsel 2005.** Initial Comments of the Colorado Office of Consumer Counsel under Docket No. 05R-112E in the Matter of the Proposed Rules Implementing Renewable Energy Standard 4 CCR 72303, available at [http://www.dora.state.co.us/occ/Cases/05R-112E\\_Amendment37\\_Rulemaking/InitialCommentsFinal.pdf](http://www.dora.state.co.us/occ/Cases/05R-112E_Amendment37_Rulemaking/InitialCommentsFinal.pdf)
- **Synapse 2005.** *Feasibility Study of Alternative Energy and Advanced Energy Efficiency Technologies for Low-Income Housing in Massachusetts*, prepared for The Low-Income Energy Affordability Network, Action for Boston Community Development, and Action Inc.

### Quantification Methods:

- (1) Estimate annualized cost of CHP and DG systems
- (2) Deduct cost savings associated with reduced fuel use for space and water heating and avoided cost of electricity;
- (3) Estimate emission reductions associated with greater energy use efficiency at end-use and with renewable energy generation.

### Key Assumptions

A large number of assumptions regarding cost, technical parameters, and technology choices were required to analyze this policy. These include:

- Average capacity factor of 60% for all CHP systems
- Avoided cost of electricity: \$56/MWh. This includes energy & capacity costs. Based on KEMA 2006. Xcel's Colorado DSM Market Potential Assessment, March 2006.
- Avoided cost of natural gas: \$7.42/mmBtu. The simple average of commercial and industrial natural gas prices for Mountain region in AEO2007. The industrial sector uses more natural gas than the commercial sector. However, because more CHP potential exists in the commercial sector, we use the simple average of fuel prices for CHP applications.
- Avoided cost of coal: \$1.7/mmBtu from AEO 2007 forecast for Industrial users in the Mountain region.
- Avoided cost of fuel oil: \$12.5/mmBtu. The simple average of commercial and industrial distillate oil price forecasts from AEO 2007 forecast for the Mountain region.
- Allocation of DG system capacity is as follows:

Residential PV Systems	35%
Commercial and Industrial (C&I) PV Systems	35%
Customer-sited Landfill Gas	10%
Customer-sited Biomass	15%
Customer-sited Biogas	5%

- Average Net Heat Rate by Fuel (Btu Fuel Input/kWh Electricity Output):

Natural Gas	10,000
Biomass	13,000

This is a placeholder estimate. Heat rates vary by the type of generator and other factors.

- Fraction of CHP Heat Output Displacing Thermal Energy by Fuel

Natural Gas	80%
Biomass	0%
Coal	4%
Electricity	10%
Oil	6%

Fraction of Fuel Usage was developed based on the following two tables.

Fuel Consumption for Commercial Space and Water Heating (trillion Btu) for Mountain Region (average between 2005 and 2020)

	Consumption	Share
Electricity	14	6%
Natural Gas	196	89%
Fuel Oil	9	4%
	219	100%

Source: These tables were created based on the table for EIA, AEO2007 National Energy Modeling System run AEO2007.D112106A. The original data was obtained from Erin Boedecker at the Commercial Energy Demand Division at EIA

Fraction of Industrial Fuel Use for Process Heat and HVAC for West Census Region

Electricity	13%
Fuel Oil	1%
Natural Gas	71%

LPG	1%
Coal	13%

Source: EIA 2002 Energy Consumption by Manufacturers. Table 5.8 - By Region with Total Consumption of Electricity (trillion Btu), available at <http://www.eia.doe.gov/emeu/mecs/mecs2002/data02/shelltables.html>

- Net Efficiency of Displaced Boiler/Heater Thermal Energy by Fuel.

Natural Gas	85%
Biomass	80%
Coal	80%
Electricity	92%
Oil	80%

- Usable Cogenerated Heat Output as a Fraction of Fuel Energy Input is assumed to be 40% for both natural gas and biomass fired CHP
- Fraction of Usable Heat Output Replacing Space/Water/Process Heat Use is assumed to be 90%
- Estimated Average Non-fuel Operating and Maintenance Costs by System Type (\$/MWh)

Natural Gas	\$10.00
Biomass	\$20.00

Source: Rough Estimates of O&M costs: O&M costs for natural gas systems are based on GRI and NREL 2004. Gas-Fired Distributed Energy Resource Technology Characterizations. O&M for other fuels are assumed to be higher than natural gas.

- Capital costs for CHP are incremental to the cost of regular space and water heating systems because CHP systems are assumed to replace space or water heating systems or both. The costs of regular space and water heating systems are assumed to be around \$1500. Incremental costs for natural gas systems are assumed to be \$1300 and to decrease to \$1040 by 2020. The incremental costs for biomass DG systems (including wood and biomass) is assumed to be \$2000 and decrease to \$1400 by 2020. The cost reduction the study period is around 20% based on EIA’s DG cost projection in AEO2007. The capital costs in 2010 are close to the weighted average capital cost of equivalent DG systems in “Self-Generation Incentive Program Data” by San Diego Regional Energy Office.

	<b>2010</b>	<b>2020</b>
Natural Gas	\$1300	\$1040
Biomass	\$2000	\$1400

- Capital cost for renewable DG systems are as follows:

	2010	2020
PV	\$8,460	\$5,978
Landfill Gas	\$3,000	\$2,400
Biomass	\$3,300	\$2,640
Biogas	\$4,000	\$3,200

The costs of PV systems are taken from the appendix to Western Resource Advocate 2004. Estimated capital costs for landfill gas and biogas based DG by 2010 are close to weighted average of the capital costs for these systems in the Self-Incentive Generation Program Data by San Diego Regional Energy Office. The cost of biomass based DG system (for wood) is assumed to be around the midpoint cost between natural gas system and biogas system. The costs are assumed to decrease by 20% by 2020. This cost reduction is based on EIA's assumption on DG costs in its AEO2007.

- Capacity factors for these technologies are:

Residential PV Systems	25%
Commercial and Industrial (C&I) PV Systems	25%
Customer-sited Landfill Gas	90%
Customer-sited Biomass	85%
Customer-sited Biogas	90%

PV capacity factor of 25% is from Colorado Office of Consumer Counsel 2005. Capacity factors for other systems are based on RPS cost impact studies in other states.

- Renewable DG systems are assumed to have the following power generation share in each year:

Residential PV Systems	15%
Commercial and Industrial (C&I) PV Systems	15%
Customer-sited Landfill Gas	20%
Customer-sited Biomass	30%
Customer-sited Biogas	20%

More wood biomass generation is assumed because its potential should be larger than other landfill gas and biogas sources. PV generation is set at only slightly lower rates because their capacity factor is lower but it has significant potential.

- Economic lifetimes of all systems are 20 years.
- Interest rates: 7% for residential customers and 8% for commercial and industrial customers
- The new Federal Solar Tax Credits (applied to system cost) is set at 10% for solar PV investments by businesses. See <http://www.seia.org/getpdf.php?iid=21>
- Value of avoided energy purchases.

## Key Uncertainties

While we have set allocations among different renewable DG systems, the technology composition of currently installed DG systems is unknown. The performance and financial characteristics we have assumed are also subject to a wide range of uncertainty.

#### **Additional Benefits and Costs**

DG provides additional benefits in terms of security of supply and reduced load on the T&D system. Other benefits include economic opportunities and diversity of supply.

#### **Feasibility Issues**

TBD

#### **Status of Group Approval**

TBD

#### **Level of Group Support**

TBD

#### **Barriers to Consensus**

TBD

## ES-7. CO<sub>2</sub> Capture & Transport Infrastructure

### Policy Option Description

Carbon dioxide capture and sequestration (CCS) in conjunction with advanced fossil fuel generation may represent one option to significantly reduce the carbon dioxide emissions associated with electricity generation in the future. One barrier to implementation of CCS on a wide scale is the absence of a pipeline infrastructure to carry carbon dioxide to suitable sequestration sites. Another barrier to CCS implementation is regulatory uncertainty in key areas such as ownership of underground sequestration resources, regulations, and long-term liability against carbon dioxide leakage. There are also uncertainties and concerns over potential adverse environmental impacts of carbon dioxide capture, transportation and storage. This policy recommendation seeks to address these barriers through policies to encourage the investigation of a regional pipeline infrastructure for CO<sub>2</sub> transport to suitable sequestration sites, and to reduce regulatory uncertainties that today hinder the planning and development of CCS projects.

### Policy Option Design

**Goal:** Work with neighboring states and the WGA to analyze options for a regional CO<sub>2</sub> transportation and sequestration collaborative. Create a workshop process resulting in a written report by state agencies to address various regulatory and environmental uncertainties associated with CCS.

**Timing:** ASAP. This has to start soon as utilities are making plans for new coal plants and should be able to count on CCS if it will become a reality.

**Coverage:** Governor's office, legislature, state agencies.

### Implementation Mechanisms

The Colorado Climate Project recommends that Governor Ritter assign the Oil and Gas Conservation Commission and the Colorado Department of Health and the Environment to investigate major regulatory and environmental issues related to CCS and to pipeline development necessary for implementation of CCS. These issues include but are not limited to appropriate government agencies to regulate sequestration sites, ownership of pore space for sequestration, regulations needed to protect public health and the environment from the full range of impacts associated with CCS and pipeline development, long-term liability for CO<sub>2</sub> storage, appropriate methods and procedures to monitor the fate of the captured and sequestered carbon dioxide, unitization of ownership of pore space rights, possibility of eminent domain for pipelines, the possible need for a state or regional carbon dioxide pipeline authority, and other issues. The process could consider whether and how federal EPA Underground Injection Control provisions might apply to CO<sub>2</sub> and how state agencies could implement them. The process could also consider a Joint Review process to streamline approvals across multiple state agencies. The process will be required to write a report to the Governor with its recommendations.

**Related Policies/Programs in Place**

None.

**Type(s) of GHG Reductions**

Facilitate CO<sub>2</sub> capture and permanent storage before reaching atmosphere, thus reducing the impact of coal combustion on the atmosphere.

**Estimated GHG Savings and Costs per MtCO<sub>2</sub>e**

This is a non-quantitative policy proposal.

**Data Sources:**

School of Mines report on CCS opportunities in Colorado;  
MIT study on “the Future of Coal” (<http://web.mit.edu/coal/>)

**Quantification Methods:**

This option will not be quantified as it relates only to a regional infrastructure research initiative.

**Key Assumptions**

Existence of significant potential for cost-effective, permanent CO<sub>2</sub> storage in region; cost and economic feasibility of constructing transport infrastructure to access these sites.

**Key Uncertainties**

Cost and extent of infrastructure needed, ultimate potential for permanent CO<sub>2</sub> storage in region. Also:

- Ownership of “pore space” or the right to sequester carbon dioxide underground
- Regulatory authority for key questions related to CCS, including appropriate government agencies to regulate sequestration sites, ownership of pore space for sequestration, long-term liability for CO<sub>2</sub> storage, unitization of ownership of pore space rights, possibility of eminent domain for pipelines, and other issues.
- Environmental and public health impacts associated with carbon capture, transportation and storage.
- Permanence of underground carbon dioxide storage.

**Additional Benefits and Costs**

TBD

**Feasibility Issues**

TBD

**Status of Group Approval**

TBD

**Level of Group Support**

TBD

**Barriers to Consensus**

TBD

**ES-8. Pricing and Rates**

*This policy option has been combined with RCI-7, Pricing and Purchasing, and analyzed through the RCI PWG.*

## ES-9. R&D for Carbon Emissions Reducing Generating Technology

### Policy Option Description

Research and development (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 could be established to help develop and deploy energy storage technologies. R&D funding can be made available to any renewable or other advanced technology through an open bidding procedure (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.

### Policy Option Design

**Goals:** 0.2 cent/kWh charge = \$20/capita-yr, \$100 million for low-interest loans to CO research companies & universities. Toward carbon emissions reducing technology

**Timing:** First funding cycle in 2009; Requests for Proposals (RFPs) circulated in 2008

**Coverage:** Colorado universities and businesses

### Implementation Mechanisms

Low-interest loans to CO research companies & universities to be funded by a per-kWh charge on electricity use, to be made available for in-state R&D on low- or non-carbon emitting sources of electricity, such as advanced solar, fuel cells, wind power, etc. The fund would *not* be available support to generating technologies which depend on carbon capture and sequestration to become low-emitting.

### Related Policies/Programs in Place

SB 246, just passed by the state legislature, provides funding for renewables and efficiency R&D.

### Type(s) of GHG Reductions

GHG reductions would occur over time as the enhanced R&D led to faster market penetration of GHG-reducing technologies.

### Estimated GHG Savings and Costs per MtCO<sub>2e</sub>

R&D benefits not quantified.

### Data Sources:

Committee on Benefits of DOE R&D on Energy Efficiency and Fossil Energy, *Energy Research at DOE: Was It Worth It? Energy Efficiency and Fossil Energy Research 1978 to 2000*, National Academy Press, Washington D.C., 2001.

### Quantification Methods:

We have not attempted to quantify the emissions benefits of investments in energy R&D in Colorado. However, one useful framework for this type of quantification was developed by a National Research Council committee (the committee) formed in 2000 to assess the benefits of DOE spending on R&D. The committee assessed benefits in three areas: economic, environmental and security. They reviewed 17 energy efficiency programs, (representing \$1.6 billion of the total \$7.3 billion energy efficiency R&D expenditures) and 22 fossil energy RD&D programs (representing nearly \$11 billion of the \$15 billion appropriated to the Office of Fossil Energy for RD&D between 1978 and 2000).

The committee came to a number of qualitative and quantitative conclusions. Among the quantitative findings were the following (all costs given in 1999\$):

- Total net realized economic benefits associated with the energy efficiency programs reviewed were approximately \$30 billion, compared to the roughly \$7 billion in total energy efficiency R&D investment over the 22-year life of the programs. (In the energy efficiency area, most of the realized economic benefits to date are attributable to three relatively modest projects in the building sector carried out in the late 1970s and 1980s and continuing into the 1990s.)
- Economic benefits of fossil programs instituted from 1986 to 2000 were estimated to be \$7.4 billion, compared to the \$4.5 billion cost of the programs during that period. Benefits associated with fossil energy programs instituted from 1978 to 1986, estimated at \$3.4 billion, were less than the cost of this period's fossil energy programs (\$6.0 billion).
- The committee had difficulty assigning a monetary value to environmental benefits, but "conservatively" estimated the environmental benefits of both R&D programs at \$60 to \$90 billion.
- The committee did not quantify security benefits.

In addition to these conclusions, the committee emphasized that the benefits of programs varied considerably across the programs studied. The committee writes: "by an order of magnitude, the largest apparent benefits were realized as (1) avoided energy costs in the buildings sector in energy efficiency and (2) avoided environmental costs from the NO<sub>x</sub> reductions achieved by a single program in fossil energy. This result is not surprising given the balanced research portfolio, which also includes its share of failures and modest successes."<sup>7</sup>

### Key Assumptions

Not applicable.

### Key Uncertainties

The areas of R&D that should be subsidized and the eventual benefits of these subsidies.

### Additional Benefits and Costs

The benefits of R&D investments can be extremely broad.

<sup>7</sup> Committee on Benefits of DOE R&D, page 6.

**Feasibility Issues**

Feasibility of additional per-kWh charges on customer bills.

**Status of Group Approval**

TBD

**Level of Group Support**

TBD

**Barriers to Consensus**

TBD

## ES-10. Promote Advanced Fossil Fuel Generation with Carbon Capture, Including IGCC

### Policy Option Description

Advanced fossil fuel generation technologies, in combination with carbon dioxide capture and sequestration (CCS), may offer one option to reduce the carbon dioxide emissions associated with fossil-fuel based electricity generation. While coal-based generation is the largest source of carbon dioxide emissions in the state, CCS may provide a cost-effective pathway to reduce carbon emissions from coal power plants while continuing to rely on an abundant, domestic source of energy. Coal generation with CCS could be based on integrated gasification combined cycle (IGCC) technology, pulverized coal technology, or some other approach yet to be determined.

Under this proposal, the Climate Action Panel recommends that:

- Governor Ritter carefully consider and evaluate the costs, GHG emission reductions, and other aspects of the Colorado IGCC with CCS project as reflected in Xcel Energy's application to the Colorado Public Utilities Commission and, based on this evaluation, support such a project if appropriate.
- Governor Ritter and Colorado's federal legislators work to obtain meaningful federal funding for the Colorado IGCC with CCS project. Federal funding would leverage the benefits of advanced coal with CCS for the entire nation, mitigate the technology risk of the project borne by Colorado utilities and ratepayers, and directly benefit Colorado's electric customers by reducing the cost of an IGCC with CCS project to ratepayers in the state.

### Policy Option Design

#### Goals:

In addition to the goals outlined above,

- Direct PUC to re-evaluate rules for demonstration projects and technology commercialization.
- Involve the state's research universities.
- Broaden policy to include advanced technologies, not just IGCC.

**Timing:** Xcel Energy is expected to propose an IGCC with CCS project in 2007 that would be operational sometime between 2013 and 2015.

**Coverage:** One generating plant

### Implementation Mechanisms

State study and, if appropriate, support for proposed project and efforts to secure federal funding to help offset the cost to state ratepayers.

### Related Policies/Programs in Place

This option is somewhat covered by existing legislation that already directs the PUC to consider approval of an IGCC plant, and to waive some of its rules on seeking least cost production.

HB 06-1281 concerns the establishment of a program to demonstrate the use of breakthrough advanced coal technology to promote low-emitting coal-fueled electricity generation.

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

If the project is built and successfully implements permanent sequestration of a significant portion of CO<sub>2</sub> from the effluent stream, GHG reduction would be the avoidance of adding these emissions to the overall atmospheric burden.

### **Estimated GHG Savings and Costs per MtCO<sub>2</sub>e**

Not quantified.

### **Data Sources:**

Not applicable.

### **Quantification Methods:**

The costs & emissions benefits for this have not been quantified.

### **Key Assumptions**

Existence of significant potential for cost-effective, permanent CO<sub>2</sub> storage in region.

### **Key Uncertainties**

Significant uncertainty in cost and benefits; potential for permanent storage of CO<sub>2</sub> in region also unknown. In addition, proposal requires infrastructure to transport CO<sub>2</sub> to suitable sequestration site (addressed in policy ES-7).

### **Additional Benefits and Costs**

Economic and employment benefits in the state, including R&D benefits associated with early implementation of technology.

### **Feasibility Issues**

- Additional risk of power plant development related to use of western coals with IGCC
- Additional risk of IGCC at higher altitude
- Additional risk of operational reliability of IGCC with CCS
- Uncertainties surrounding the permanence of the captured carbon dioxide being sequestered from the atmosphere and any potential adverse environmental impacts from geologically sequestering carbon dioxide.

### **Status of Group Approval**

TBD

### **Level of Group Support**

TBD

## **Barriers to Consensus**

A PWG member expressed support, but argued that CO<sub>2</sub> intensity should be addressed. The concern was that the technology may only sequester a small percentage of the CO<sub>2</sub> produced.

## ES-11. Small New Hydro and Efficiency Improvements at Existing Hydro, Identifying Other Small Renewables and Removing Barriers Thereto

### Policy Option Description

Currently, existing hydroelectric plants in Colorado produce about 1,200 GWh of electric energy per year. This energy is produced from plants built in the early 1920's and before as well as relatively newer units. Older plants present opportunities for improvements in efficiency and production including more efficient turbines, upgraded generator windings and replacement of mechanical controls with solid state equipment. The improvement in efficiency and plant production can range from 1-2% to as high as 25-30%.

In addition, several studies have suggested there may be 1000 MW or more of hydroelectric potential in Colorado at existing dams and water impoundments, diversions and conveyance structures. Research suggests that the capacity and generation efficiency of many existing hydro projects could be increased. The U.S. Bureau of Reclamation has uprated 50 units since beginning its uprate program in 1978, at an average cost of \$68 per new kW.<sup>8</sup> In addition to this capacity, we believe the potential for new, small hydroelectric projects is considerable, but more work needs to be done to characterize this resource. Sites for potential projects include existing impoundments and diversions as well as networks such as municipal water systems. Most municipal water systems include numerous pressure release valves, and these valves can be replaced by small turbines that generate electricity.

Depending on site-specific factors, small hydroelectric projects may be cost competitive with both fossil-fueled and other renewable power sources. With the recent enthusiastic acceptance of wind energy programs, it is reasonable to expect that small hydroelectric energy programs based on local resources would also be favorably received by customers.

There are also sites in Colorado suitable for developing pumped storage hydro facilities, which allow off-peak generation to be shifted to peak periods. However, from the perspective of GHG emissions it is important to consider both the loss of efficiency associated with pumped storage and what energy source is used to power the pumping. If coal, the effective emission rate of the pumped storage energy is actually *higher* than that of the coal plant due to pumping losses. However, storage of renewable energy in a pumped storage facility could be an effective GHG mitigation strategy. Use of pumped storage to take full advantage of intermittent wind generation is particularly attractive.

The primary barrier to development of hydroelectric facilities is that the water facilities are owned and operated by entities without expertise in power production. Also, the generation potential of each site is usually small and often overlooked by power providers. In fact, all small

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<sup>8</sup> U.S. Bureau of Reclamation, Generator Power Uprate Program Report, July 2000. Available at: [www.usbr.gov/power/data/uprate/uprate.html](http://www.usbr.gov/power/data/uprate/uprate.html).

renewable resources face barriers similar to these: the site owner rarely has experience in power generation, and power production per site is relatively small, making it more difficult to justify the investment in feasibility studies and other up-front costs. However, when considered as a whole, these small sites may represent a significant amount of zero-carbon energy. More research is needed to identify and remove barriers to small, distributed renewable generators.

### **Policy Option Design**

**Goals:** Begin with statewide mapping of unexploited potential of geothermal, small hydro, and biomass (expanded SB-91). Follow with:

- Address institutional barriers to small renewables;
- Seek to add 50 MW of new, small hydro resources per year beginning in 2014;
- Consider transferring oversight from FERC to the state in order to streamline permitting. Permitting should include environmental certification, based on models DOE already has in place.

Establish a work group to research barriers to small renewable energy facilities and propose solutions.

**Timing:** Mapping and small renewables work group to begin immediately.

**Coverage:** Statewide.

### **Implementation Mechanisms**

Note implementation details above.

Mapping could be performed by the Colorado Universities in conjunction with experts from federal agencies. Developers of small hydro projects would have access to any subsidies that are established and revenue from energy credits under an RPS. The small renewables work group could be led by the Governor's Energy Office.

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

SB-91: Existing statewide mapping program.

The U.S. Bureau of Reclamation has uprated 50 units since beginning its uprate program in 1978, at an average cost of \$68 per new kW.

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

CO<sub>2</sub> emissions reductions associated with avoided fossil-fueled generation.

**Estimated GHG Savings and Costs per MtCO<sub>2</sub>e**

	Policy Option	GHG Reductions (MMtCO <sub>2</sub> e)			Net Present Value 2007–2020 (Million \$)	Cost-Effectiveness (\$/tCO <sub>2</sub> e)
		2012	2020	Total 2007- 2020		
ES - 11	Small New Hydro and Efficiency Improvements at Existing Hydro, Identifying Other Small Renewables and Removing Barriers Thereto	0	0.8	3	\$123	\$40

The PWG agreed to assume a cost of \$3,000/kW for all new small hydro resources in the state and a capacity factor of 35%. We assume a 40-year economic life for these facilities and a capital recovery factor of 10.2%, yielding a nominal cost of \$105/MWh. The sensitivity of the cost of these resources to these assumptions is shown in the table under “Key Assumptions”, below.

We evaluated the addition of 50 MW per year of small hydro between 2014 and 2020. Assuming that 75% of the energy from these projects displaces coal-fired generation and 25% of it displaces gas-fired generation, each 50-MW block of capacity would eliminate roughly 111,000 metric tons of CO<sub>2</sub> emissions annually. In 2020, the entire 350-MW block would be displacing approximately 774,000 tons annually – or about 1.5% of total state emissions in the reference case.

The NPV (2007) of the cost of this program is calculated as \$123 million, and the total avoided emissions during this period would be 3 MMtCO<sub>2</sub>e. This yields a per-ton avoided cost of approximately \$40 through 2020.

**Data Sources:**

Hydro mapping efforts at the national level include the following:

- U.S. Department of Energy, *Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plants*, DOE-ID-11263, January, 2006,
- Idaho National Engineering and Environmental Laboratory, *Estimation of Economic Parameters of U.S. Hydropower*, INEEL/EXT-03-00662, June 2003.
- James Francfort, U.S. Hydropower Resource Assessment for Colorado, DOE/ID-10430, May 1994.

However, these studies use GIS databases and other models to estimate the developable hydro capacity within a state. They provide little of the information needed to assess the cost and feasibility of a site for a small hydro project. Thus, a state mapping effort, using tools that can provide this information, is critical.

**Quantification Methods:**

- Start with the revised reference case;
- Use “small hydro” as a proxy for all unexploited small renewable resources;

- Add in 50 MW per year of hydro capacity at \$3000 per kW and a 35% capacity factor;
- Assume the hydro energy displaces 75% new coal-fired generation and 25% new gas-fired generation and that the long term avoided cost of generation is \$56/MWh.

**Key Assumptions**

- The assumptions of a “flat supply curve” at \$3,000 per kW and a 35% capacity factor drive the cost estimate in this analysis. For context, the cost matrix below shows the estimated cost of a two-MW hydro energy at different capital cost points and capacity factors.

		<b>Capacity Factor</b>			
		30%	50%	70%	90%
<i>MWh/yr:</i>		5,256	8,760	12,264	15,768
<b>Cost (\$/kW)</b>	<b>Principal (\$M)</b>	<b>Levelized Cost (\$/MWh)</b>			
\$ 1,000	\$ 2.00	\$ 43.91	\$ 28.35	\$ 21.68	\$ 17.97
\$ 2,000	\$ 4.00	\$ 82.82	\$ 51.69	\$ 38.35	\$ 30.94
\$ 3,000	\$ 6.00	\$ 121.73	\$ 75.04	\$ 55.03	\$ 43.91
\$ 4,000	\$ 8.00	\$ 160.65	\$ 98.39	\$ 71.71	\$ 56.88

- We assume that 350 MW of small hydro capacity can be installed at certified environmentally acceptable sites by 2020, at existing federal and non-federal impoundments and diversions
- We assume the existence of up to 500 MW of accessible but unexploited small hydro.
- We assume institutional, structural, and jurisdictional barriers can be overcome at reasonable cost.

**Key Uncertainties**

Total capacity is available at feasible, undeveloped sites

Supply curve of small hydro and other small renewables capacity – i.e., how much capacity is available at what price?

Distribution of capacity factors and operating costs of actual small hydro and other small renewable projects.

**Additional Benefits and Costs**

Small hydro and other small renewable energy projects provide landowners with an additional revenue stream; other economic benefits including employment benefits.

**Feasibility Issues**

What would a mapping project that could provide the needed information look like? Who is best suited to do it?

Actual technical and economic potential of small renewables on CO;

Jurisdictional, ownership, and zoning issues;

Transmission availability and access for small power projects.

**Status of Group Approval**

TBD

**Level of Group Support**

TBD

**Barriers to Consensus**

TBD

## ES-12. Nuclear Energy

### Policy Option Description

Electricity generation accounts for 37% of Colorado's greenhouse gas emissions or about 43 million tons of CO<sub>2</sub> annually. Of that, coal-fired plants emit 35 MMT. This amount is slated to increase to 48 MMT per year by 2020 in the Reference Case projection. Since nuclear plants also produce base load power, they are potentially a direct replacement for coal-fired plants. As a GHG reduction tool, this gives nuclear a significant advantage of over intermittent technologies like wind and solar.

During operation, nuclear plants generate no GHGs, although there are GHG emissions associated with the mining, refining, and transport of nuclear fuel and the decommissioning of plants. The feasibility of new nuclear power plants in the U.S. clouded by several serious and interrelated issues relating to costs, safety, management of radioactive waste and the proliferation of nuclear materials.

This GHG mitigation proposal is to take actions at the state level to facilitate the licensing, financing, and construction of new nuclear power plants in Colorado.

### Policy Option Design

**Goals:** literature review of costs of new nuclear power plants

**Timing:** N/A

**Coverage:** N/A

### Implementation Mechanisms

N/A

### Related Policies/Programs in Place

N/A

### Type(s) of GHG Reductions

New nuclear generation in Colorado would reduce the operation of existing coal-fired plants and/or defer the need for new ones.

### Estimated GHG Savings and Costs per MtCO<sub>2</sub>e

Non-specific policy not quantified.

### Data Sources:

Massachusetts Institute of Technology, *The Future of Nuclear Power: An Interdisciplinary MIT Study*, 2003, ISBN: 0-615-12420-8.

The Keystone Center, *Nuclear Power Joint Fact-Finding*, June 2007.

U.S. Energy Information Association, *Assumptions to the Annual Energy Outlook, 2007*, April 2007, Report #: DOE/EIA-0554(2007).

### Quantification Methods:

We have not quantified potential costs and emission reductions associated with this policy due to considerable uncertainties around the cost and feasibility of new nuclear capacity. We found two studies that assess the potential costs of new nuclear capacity in the U.S. and the uncertainties surrounding it. The first is an interdisciplinary study from the Massachusetts Institute of Technology (MIT study), and the second is the report of a stakeholder research group brought together by the Keystone Center (Keystone study). Both studies focus on uncertainties in four main areas. The MIT authors write:

- Costs – nuclear plants have higher overall lifetime costs than gas- and coal-fired plants;
- Safety – nuclear power has perceived adverse safety, environmental and health effects;
- Proliferation – nuclear power entails potential security risks; and
- Waste – nuclear power has unresolved challenges in the long-term management of radioactive wastes.<sup>9</sup>

Estimates of the cost of energy from new nuclear units are highly uncertain. The table below shows three cost estimates. The first estimate is from the MIT study; the second is from the Keystone study; and the third is the cost that the U.S. Energy Information Agency (EIA) uses in its energy modeling. (The levelized cost of energy in the EIA model falls from 6.3 to 5.8 ¢/kWh over the period 2015 to 2030.) The MIT Study assumes a capacity factor of 85% and assumes that non-fuel O&M costs for a new plant can be reduced by 25% relative to the current fleet average. Since their O&M costs are quite close, it seems that EIA has made a similar assumption about O&M costs.

**Projected Costs of New Nuclear Energy in the U.S. (2005\$)**

	MIT Study <sup>10</sup>	U.S. EIA <sup>11</sup>	Keystone Center
Overnight cost (\$/kW)	2,100	2,081	3,420 – 3,800
Debt/Equity ratio	50/50	unknown	50/50
Cost of debt/equity	8%/15%	unknown	8%/15%
Construction period (yrs)	5	6	5 - 6
Economic life (yrs)	25 - 40	40	30 - 40
Fuel (¢/kWh)	unknown	0.5 - 0.6	1.2 - 1.6
O&M (¢/kWh)	unknown	0.9	2.3 - 3.0
Fuel + O&M (¢/kWh)	1.6	1.4 - 1.5	3.5 - 4.7
Levelized energy cost (¢/kWh)	7.0 - 7.4	6.3 – 5.8	7.9 -10.6

Costs are presented in 2005 dollars. Dollars from the MIT and Keystone studies have been converted from 2003 and 2007, respectively.

<sup>9</sup> Massachusetts Institute of Technology, *The Future of Nuclear Power: An Interdisciplinary MIT Study*, 2003, ISBN: 0-615-12420-8, p. 2.

<sup>10</sup> Massachusetts Institute of Technology, p. 42-43.

<sup>11</sup> U.S. EIA, Table 38, p. 72.

While there is some uncertainty around all cost components, the uncertainty around the terms of plant financing is particularly large. The current fleet of nuclear plants in the U.S. was built within a heavily regulated industry, and as the MIT authors note, “many of the risks associated with construction costs, operating performance, fuel price changes and other factors were borne by consumers rather than suppliers.” It is unclear whether capital markets will be willing to take on the perceived risks of merchant nuclear plants in today’s competitive bulk power markets – and if they are, they may well demand risk premiums considerably higher than those assumed in the MIT study.

However, as the Keystone study notes, “competitiveness cannot be gauged entirely by comparing financial numbers,” and questions about nuclear costs may prove to be small compared to concerns about safe plant operation, safety of the fuel cycle and the proliferation of nuclear materials represent major barriers. In a post-9/11 world, concerns about the security of nuclear plants and fuel processing facilities may loom as large in the public mind as concerns about reactor safety and waste containment. In short, it is not at all clear that these issues could be resolved to the satisfaction of public officials and the public at large. Further, the resolution of these issues might well place additional costs on prospective plant owners, adding to the economic challenge.

Finally, when considering nuclear energy as a GHG-reduction strategy, the issue of lifecycle emissions becomes important. There is considerable fossil fuel combustion in the mining, enriching and transportation of nuclear fuel and the decommissioning of plants, and this fuel use is not well documented. Nuclear fuel-cycle emissions probably constitute a fraction of the per-kWh emissions from a coal-fired plant, but more work needs to be done to quantify these emissions.

### **Key Assumptions**

Costs and emission reductions not quantified.

### **Key Uncertainties**

- The cost of a new nuclear plant in Colorado.
- The actual emissions benefit of nuclear energy over coal-fired generation fossil, accounting for emissions associated with fuel processing.

### **Additional Benefits and Costs**

TBD

### **Feasibility Issues**

- Can a new nuclear plant be sited and licensed in Colorado? The siting and licensing proceedings (and potentially voter referenda) will be the battleground for safety, proliferation and waste management issues.
- Are capital markets willing to invest in a merchant nuclear plant at terms that do not impose unacceptable costs?
- Waste storage issues.

### **Status of Group Approval**

TBD

**Level of Group Support**

TBD

**Barriers to Consensus**

TBD

## ES-13. Efficiency Improvements for Existing Generators (Includes Heat Recovery)

### Policy Option Description

Making efficiency improvements at existing generation stations has a number of benefits such as: offsetting the rising cost of fuel, reducing overall emissions and improving plant reliability. This can be done through improvements in both the combustion and steam cycles, as well as with waste heat recovery.

Efficiency improvements at existing generating stations may be hampered by federal regulation, lawsuits and uncertainty. New Source Review (NSR) and New Source Performance Standard (NSPS) regulations need to be clarified and should encourage, not discourage, efficiency improvements such as turbine upgrades, motor, pump, fan and drive improvements, control system upgrades and recovery of waste heat. Though these are Federal programs, the State of Colorado may be able to help mitigate potential regulatory issues associated with such improvements. Public policy could specifically encourage the State to utilize its regulatory discretion to streamline the process of evaluating a plant's NSR and NSPS requirements. Reform of NSR could be addressed in any carbon control regulations to encourage plant efficiency. One option is to reinstate the pollution control project (PCP) exemption and broaden it to include significant plant upgrades such as turbine replacements. Another option is to require issuance of construction permits for efficiency projects on a more timely basis (e.g. permits processed within 12 months).

Efficiency improvements at existing generating stations may also be hampered by lack of regulatory cost recovery certainty for regulated investor-owned utilities under the jurisdiction of the Colorado Public Utilities Commission (PUC). Public policy could specifically encourage the PUC to allow for the recovery of costs for efficiency improvements at existing generators. These efficiency improvements could reduce customer energy costs as well as carbon dioxide emissions.

### Policy Option Design

**Goals:** 5% overall improvement in generator efficiency by 2020

**Timing:** Utilities report total heat input/total MWh output in 2008; first year of reduction is 2011. Use imputed value for purchases unless specific data are provided.

**Parties involved:** All generation owners in CO.

**Other:** As needed, identify incentives that encourage plant efficiency improvements and utilization of new technology to reduce emissions.

### Implementation Mechanisms

See above.

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

None specified.

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

Efficiency improvements on plants; replacement of coal with gas over time.

### **Estimated GHG Savings and Costs per MtCO<sub>2e</sub>**

Quantitative analysis pending.

### **Data Sources:**

I&F as source for BAU generation sources in Colorado.

### **Quantification Methods:**

Begin with cost curve for efficiency improvements in existing plants in Colorado

Estimate required stock turnover and replacement technology to achieve these reductions.

### **Key Assumptions**

Costs not to include additional costs associated with NSR regulations, if applicable.

Technical and economic feasibility of reaching goal.

### **Key Uncertainties**

- Potential for and cost of efficiency improvements at existing plants.
- Heat rates of future generating technologies.
- Efficiency improvements at existing generating stations may be hampered by federal regulation, lawsuits and uncertainty
- New Source Review (NSR) regulations could raise the cost of meeting this goal.
- Availability and price of natural gas

### **Additional Benefits and Costs**

Lower overall cost of producing electricity at more efficient plants; economic opportunities and employment.

### **Feasibility Issues**

See uncertainties.

### **Status of Group Approval**

TBD

### **Level of Group Support**

TBD

### **Barriers to Consensus**

TBD

## ES-14. Oil and Gas Operations

### Policy Option Description

There are a number of ways in which Greenhouse Gas (GHG) emissions in the oil and gas industry, particularly CO<sub>2</sub> and methane, can be mitigated. Methane is a potent GHG, so any leaks during production, processing, and transportation/distribution should be addressed. Eliminating these leaks can be economically beneficial because it prevents the waste of valuable product. The EPA Natural Gas STAR program offers numerous methods of preventing leaks.

### Policy Option Design

**Goals:** 35% reduction below 2004 levels in GHG emissions from methane relative to baseline case.

Also reduce uncertainty in methane losses (target for increased accuracy)

**Timing:** Achieve level of reduction by 2020

**Parties involved:** Colorado oil and gas permittees.

### Implementation Mechanisms

This policy aims to reduce methane emissions from gas and oil operation gradually, starting in 2009 and reaching a 35% reduction relative to 2004 emission by 2020.

The CCAP recommends that Colorado focus attention on reducing GHG emissions from fuel combustion in the oil and gas industry through education, financial incentives, mandates and/or standards – coupled with cost and investment recovery mechanisms, if appropriate.

### Related Policies/Programs in Place

In 2006, EnCana installed emission control units to control VOC flash emissions associated with condensate storage tanks. The company installed 172 emissions control units at \$20,000 per unit. The company has not finished its emission inventory, and thus has not identified the amount of methane reduction from this measure. EnCana reported that this measure reduced its VOC emissions from 2004 to 2006 by approximately 40%. (Personal communication with PWG member Chris Williams of EnCana in July 2007)

### Type(s) of GHG Reductions

Reduced methane emissions from oil & gas operations.

**Estimated GHG Savings and Costs per MtCO<sub>2e</sub>**

	Policy Option	GHG Reductions (MMtCO <sub>2e</sub> )			Net Present Value 2007–2020 (Million \$)	Cost-Effectiveness (\$/tCO <sub>2e</sub> )
		2012	2020	Total 2007- 2020		
ES - 14	Oil and Gas Operations	0.8	3	16	\$12	\$0.8

**Data Sources:**

Cost of Methane Reduction:

- U.S. EPA. “EPA Natural Gas STAR Program,” available at [www.epa.gov/gasstar/](http://www.epa.gov/gasstar/) and <http://www.epa.gov/gasstar/techprac.htm>

**Quantification Methods:**

Cost of reduced methane based on the data available from U.S. EPA’s Natural Gas Star Program is used to estimate the level of investment that is necessary to achieve the policy target.

**Key Assumptions**

Parameter	Value	Notes
Cost of Saved Methane	\$0.487 per Mcf of methane	This figure is based on (1) 20 year leverage lifetime of methane reduction measures, (2) 5% real discount rate, and (3) the average cost of saved methane based on performance by a number of methane reduction projects under U.S. EPA Gas Star Program.
Methane Emission Rate	0.404 ton of CO <sub>2e</sub> per Mcf of CH <sub>4</sub>	U.S. EPA. Natural gas methane unit converter, available at <a href="http://www.epa.gov/gasstar/pdf/unitconverter_final.pdf">www.epa.gov/gasstar/pdf/unitconverter_final.pdf</a>

**Key Uncertainties**

Cost and feasibility of reaching target.

**Additional Benefits and Costs**

Recovery of valuable product;

Avoidance of methane emissions to the atmosphere, which contributes to the production of pollutants such as NO<sub>x</sub> and O<sub>3</sub>.

**Feasibility Issues**

Further study and analysis of the approaches recommended above by the Colorado Department of Public Health and Environment and other appropriate agencies may suggest changes in goals and determinations regarding the economic and technical feasibility of these approaches.

**Status of Group Approval**

TBD

**Level of Group Support**

TBD

**Barriers to Consensus**

TBD

## ES-15. CO<sub>2</sub> Emissions Standards for Power Plants

### Policy Option Description

A carbon dioxide emissions performance standard is an emissions standard requiring that all new non-peaking power plants located in Colorado or serving Colorado electricity customers have carbon dioxide emission no greater than 1,100 pounds of CO<sub>2</sub> per megawatt-hour. In addition, to ensure that power providers have the necessary incentives to invest in new low- carbon dioxide emitting facilities rather than continue to operate aging high-carbon dioxide emitting plants the standard would also apply to existing facilities once they reach 60 years of age. The 1,100 pounds per megawatt-hour standard is based on the level of emissions of a new efficient natural gas plant.

### Mitigation Option Design

**Goal:** Establish a power plant carbon dioxide emission standard of 1,100 pounds CO<sub>2</sub> per megawatt-hour for non-peaking plants. (Peaking is CF < 10%) Applies to new power sold in the state of Colorado, or 60+ year-old plants

**Timing:** As soon as possible.

**Coverage:** Would apply to all new non-peaking power plants, or those that have operated for 60 year or more, that are located in Colorado or that provide power to Colorado electricity customers.

### Implementation Mechanisms

Would be adopted as a regulation at the state level.

Given the lead time of constructing new fossil fuel plants, a standard established today would impact new plants that come on-line after 2011 and any that have been in operation 60 years or more.

### Related Policies/Programs in Place

None identified.

### Type(s) of GHG Reductions

Displaced emissions associated with overall improvement of generating fleet efficiency relative to baseline scenario..

**Estimated GHG Savings and Costs per MtCO<sub>2</sub>e**

	Policy Option	GHG Reductions (MMtCO <sub>2</sub> e)			Net Present Value 2007–2020 (Million \$)	Cost-Effectiveness (\$/tCO <sub>2</sub> e)
		2012	2020	Total 2007- 2020		
ES - 15	CO <sub>2</sub> Emission Standards for Power Plants	0.5	2	13	\$14	\$1

Note that capital cost savings from building natural gas instead of coal plants almost offset the higher cost of natural gas relative to coal.

**Data Sources:**

I&F, industry standard estimates of delivered plant costs. EIA Annual Energy Outlook for 2007.

**Quantification Methods:**

Policy design is to replace all new coal plants in baseline I&F, as well as all plants over 60 years old, with a portfolio of resources including energy efficiency, renewables, perhaps some gas and IGCC or other advanced coal technologies that meets the emission standard.

The analysis shown is limited to estimating cost and emissions impact of replacement of all new coal generation (heat rate 9000 Btu/kWh) in the reference case with natural gas combined cycle generation (heat rate 7000 Btu/kWh).

**Key Assumptions**

Cost of new plants & fuel unaffected by altered investment strategy.

**Key Uncertainties**

Future costs of natural gas and coal; availability and cost of generating technology..

**Additional Benefits and Costs**

None identified.

**Feasibility Issues**

Trying to apply this standard to non-Colorado facilities may violate interstate commerce clause. This may be rectifiable if the requirement is for portfolio of power purchased by LSEs. (This issue has been discussed extensively in the RGGI process.)

**Status of Group Approval**

TBD

**Level of Group Support**

TBD

## **Barriers to Consensus**

A PWG member stated that this approach is short sighted and ignores issues of gas availability, and alternative gas uses such as fertilizer production. It could also lead to migrating of jobs off-shore.