

## ES-11 CO<sub>2</sub> Capture and Storage or Reuse (CCSR)

### Policy Description:

*CCAG Summary:* Carbon capture and storage or reuse (CCSR) involves capturing carbon and either (1) sequestering it in a geologically sound reservoir or (2) reusing the carbon to aid in natural gas extraction or as a feedstock for industrial processes, and perhaps eventually as a feedstock that when combined with water can be reformed into liquid fuels. Carbon can and is captured in natural gas extraction; natural gas can have only up to 2.5% CO<sub>2</sub>, and some gas fields have a much higher concentration. Excess CO<sub>2</sub> is removed and is currently typically emitted to the atmosphere. Carbon can also be captured in the process of gasifying coal to liquid fuels. This process is well established in the chemical industry and forms the basis for Integrated Gasification Combined Cycle electricity generating plants. Potentially, carbon could also be captured directly from the atmosphere.

Policies to encourage CCSR could include a state agency or department within an existing agency tasked with promoting CCSR, evaluation studies to identify geologically sound reservoirs, R&D funding to improve CCSR technologies, financial incentives to capture and store carbon or to capture and reuse it, and/or mandates to capture and store carbon or capture and reuse it.

### Policy Design:

The CCAG recommends that New Mexico task a state agency (e.g., OCD, which has this regulatory authority) to provide technical resources for carbon sequestration, including an evaluation of suitable storage sites, and possibly the administration of financial incentives. Implementation could include financial incentives, mandatory measures, or both. The CCAG recommends further evaluation to identify regulatory, technical, and economic factors affecting the use of acid gas injection in New Mexico.

The group recommended separate analyses of CCSR for power plants and the oil and gas industry. With respect to the oil and gas industry, the group suggested focusing on capturing the CO<sub>2</sub> currently being vented at natural gas processing plants and on acid gas injection at sour gas processing plants. In addition, carbon emissions from fluid catalytic cracking units at oil refineries should be evaluated.

- **Goal levels:** Starting in 2007, use acid gas injection for 100% of all sour gas processing by 2020; capture, store, and/or reuse 7% of CO<sub>2</sub> emissions from natural gas processing every year (calculated as 7% of the prior year's emissions).
- **Timing:** Acid gas injection by 2020; CCSR for natural gas processing to 2050.
- **Parties:** As noted above.

### Implementation method(s):

Likely mechanisms that could be used include:

- Education and information.
- Funding mechanisms and or incentives.
- Pilots and demonstration projects.
- Research and development.
- Voluntary and or negotiated agreements.
- Codes and standards – Identification and elimination of regulatory obstacles; and/or development of regulatory mandates.

**Related Policies/Programs in place:**

- New Mexico currently does not have any written policy encouraging the use of CCSR. However, New Mexico does have a regulation authorizing acid gas injection for the oil and gas industry, and has permitted acid gas injection wells in the Permian Basin.

**Type(s) of GHG Benefit(s):**

- CO2: If carbon were successfully stored in appropriate geological reservoirs, the net emission of carbon would be substantially reduced.

**Estimated GHG Savings and Costs Per Ton:**

#	Policy	Scenario	Reductions (MMTCO2e)			NPV (2007– 2020) \$ Millions	Cost- Effective- ness \$/tCO2
			2012	2020	Cumulative Reductions (2007-2020)		
ES-11	CO2 Capture and Storage or Reuse (CCSR)	Use acid gas injection for all sour gas processing by 2020.	.22	.48	3.35	27.90	\$8.33
ES-11	CO2 Capture and Storage or Reuse (CCSR)	Capture, store, and/or reuse CO2 emissions from natural gas processing at a rate of 7% every year.	.97	2.23	34.9	-11.76	-\$0.34
ES-11	<b>CO2 Capture, Storage, and Reuse</b>	<b>Sum of two scenarios above two.</b>	<b>1.19</b>	<b>2.71</b>	<b>38.25</b>	<b>16.14</b>	<b>\$0.42</b>

**Data Sources, Methods and Assumptions (for quantified actions):**

- **Data Sources:** Herzog and Golomb (2004) *Carbon capture and storage from fossil fuel use*, Massachusetts Institute of Technology Laboratory for Energy and the Environment; Herzog et al. (1997) *CO2 capture, reuse, and storage technologies for mitigating global climate change*; Benson et al., *Carbon dioxide reuse and sequestration: the state of the art today*; Sikora et al., *Economic and emission accounting for acid-gas injection projects—an example from Keyspan Brazeau River, Alberta, Canada*; Bachu et al. (2003) *Characteristics of acid gas injection operations in western Canada*; State of New Mexico.
- **Quantification Methods:** Cost/ton estimates were derived primarily from Sikora et al. and Herzog and Golomb (2004). Overall cost of acid gas injection (“AGI”) was determined by taking the average overall cost and averaging it with the cost after savings when replacing a sulfur recovery plant. Overall cost of CCSR was determined by taking the average cost/ton of CO2 reduction achieved through the use of enhanced oil recovery, enhanced coalbed methane recovery, injection and storage into depleted gas reservoirs, injection and storage into depleted oil reservoirs, and injection and storage into deep saline aquifers. Reduction goals were established based on consideration of (1) availability of technology and reports on effectiveness, (2) amount of CO2 reduced, and (3) cost.

Cumulative CO2 reductions from acid gas injection were determined based on linear progress toward meeting the overall reductions. Net present value was calculated using a 5% annual discount rate.

AGI is widely used in Alberta, Canada, where an estimated 0.25 Mt/year of CO<sub>2</sub> are injected annually into deep saline aquifers and depleted oil and gas reservoirs. In 2002, there were 39 active AGI sites in Alberta. In New Mexico, the use of AGI is allowed, and AGI wells may be in operation.

Savings from AGI can be obtained through the replacement of sulfur recovery units. Estimated costs of sulfur recovery and AGI, including CO2 capture costs, based on Sikora et al., are as follows:

Item	AGI Cost	Sulfur Recovery cost (380 ton/day inlet)
Capital cost (\$ million)	24.9	31
Operating costs (\$ per year)	2,172,000	3,348,000
Operating costs without fuel gas (\$ per year)	750,000	1,160,000
Fuel gas cost (\$ per year)	1,422,000	2,188,000
Total annualized cost per year	\$6,032,000	\$8,153,000

A comparison between sulfur recovery (at a 400 ton/day processing facility) and AGI determined that net CO<sub>2</sub> emission reductions from AGI total 129,233 tons/year. AGI

can reduce CO<sub>2</sub> emissions by as much as 73% when compared to sulfur recovery according to field reports.<sup>1</sup>

A total reduction of 129,233 tons/year of CO<sub>2</sub> is assumed from the use of AGI and an estimated savings of \$2,121,000 when compared to sulfur recovery. This yields a payback of \$16.41/ton of CO<sub>2</sub> reduced. However, if acid gas is simply flared or otherwise uncontrolled, costs could be as high as \$46.67. This yields an average overall estimated cost/ton of CO<sub>2</sub> reduced of \$15.13.

With CO<sub>2</sub> emissions from sour gas production estimated to be 656,057 tons/year based on reference case forecast data prepared by Michael Lazarus, and considering a 73% reduction efficiency, this yields a cumulative CO<sub>2</sub> reduction of 3.35 MMt/CO<sub>2</sub> reduced by 2020, based on linear progress toward meeting the suggested goal.

For CCSR from non-sour gas processing, other capture, storage, and/or reuse options that are available in New Mexico include enhanced oil recovery, enhanced coalbed methane recovery, injection into depleted gas reservoirs, injection into depleted oil reservoirs, and injection into deep saline formations. The cost/ton of CO<sub>2</sub> reduced for storage, based on Herzog and Golomb and Herzog et al., is summarized below:

Option	Cost/ton CO <sub>2</sub> reduction
Enhanced Oil Recovery	-12.21
Enhanced coalbed methane	-5.59
Injection into depleted gas reservoirs	4.87
Injection into depleted oil reservoirs	3.82
Injection into deep saline aquifer	2.93

Average overall cost for CCSR using these options is thus -\$1.24/ton CO<sub>2</sub> reduced.

- Key Assumptions:** It was assumed that the cost of CO<sub>2</sub> capture at natural gas processing plants is a small fraction of overall costs, and thus is negligible. It was assumed that total CO<sub>2</sub> emissions from sour gas processing are 656,057 tons/year, based on production rates from the southeast Permian Basin, and that a 73% reduction efficiency could be achieved through the use of AGI. It was also assumed that overall costs stated in Sikora et al. accurately reflect average costs of AGI in New Mexico.

It was assumed that CO<sub>2</sub> emissions from the remainder of natural gas processing (i.e., outside and therefore excluding emissions from the SE Permian Basin) average 3,843,943 tons/year, based on reference case forecast data prepared by Michael Lazarus.

Flat production rates, and therefore consistent emission rates, were assumed to reflect overall production growth and/or declines. It was assumed that all CCSR options are available and feasible to meet the stated goals. According to available data, there is a potential to recovery 17 Tcf of natural gas through ECBMR in the San Juan Basin, with a CO<sub>2</sub> sequestration potential of 2.8 Gt.<sup>2</sup> Information from industry suggests

<sup>1</sup> Sikora et al., *Economic and emission accounting for acid-gas injection projects—an example from Keyspan Brazeau River, Alberta, Canada*

<sup>2</sup> Advanced Resources International, Inc. (2002).

that EOR is being utilized in the southeast Permian Basin with success and that ECBMR is likely profitable in the San Juan Basin.<sup>3</sup> Incentives also exist in New Mexico for the use of EOR.<sup>4</sup>

#### **Key Uncertainties:**

- Uncertainties exist as to the length of time CO<sub>2</sub> will remain in storage in suitable geologic formations. Uncertainties exist as to the availability of suitable geologic formations in New Mexico as such data was not available at the time of this assessment. Natural gas production and processing rates may also vary over time.

Uncertainties exist as to the production rates of sulfur recovery units and the degree to which sulfur recovery units are utilized. If sulfur recovery units are more widely utilized, average cost of AGI could be lower; if they are less widely utilized, average AGI cost could be higher.

Use of CCSR options may vary. For example, ECBMR costs may be higher than stated. The overall average cost was intended to capture flexibility in the implementation of CCSR options, and thus allow greater use of one or more options over others.

#### **Contributing Issues, if applicable:**

- The reuse of carbon dioxide through enhanced oil and coalbed methane recovery could lead to increased production and increased economic development.
- Acid gas injection is already being used in New Mexico and is widely used in Canada.
- Acid gas injection could virtually entirely eliminate the emission of sulfur dioxide and hydrogen sulfide removed from field gas.
- Acid gas injection could replace or reduce the capital and O&M costs associated with sulfur control equipment at natural gas processing plants.
- Storing carbon in geological reservoirs carries with it a risk that the carbon would eventually leak out. If this were to happen, carbon storage would serve only to delay carbon emissions. There is also a risk, though perhaps small, of a sudden release of carbon from reservoirs. If near populated areas, a sudden substantial release could be dangerous.

#### **Feasibility Issues, if applicable:**

- Cost may vary and present feasibility questions depending on the choice of capture, storage, and reuse options and the location of their implementation. Feasibility may also depend on the uncertainties stated above.

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

Pending.

<sup>3</sup> *Supra*, note 3 and Herzog and Golomb (2004). See also e.g., [http://www.oxy.com/OIL\\_GAS/technology/enhanced\\_recovery.htm](http://www.oxy.com/OIL_GAS/technology/enhanced_recovery.htm).

<sup>4</sup> See, <http://www.state.nm.us/tax/forms/ogas/rpd41163.pdf>.

**Level of Group Support:**

TBD.

**Barriers to consensus (if less than unanimous consent):**

TBD.

## ES-12 Methane Reduction in Oil & Gas Operations (BMPs & PROs)

### Policy Description:

*CCAG Summary:* There are a number of ways in which methane emissions in the oil and gas industry can be reduced. Natural gas consists primarily of methane, so any leaks during production, processing, and transportation/distribution should be addressed. In addition to reducing potent GHG emissions, stopping these leaks is economically beneficial because it prevents the waste of valuable product. The EPA Natural Gas STAR program offers numerous methods of preventing leaks. These methods, called Best Management Practices (BMPs) and Partnership Reduction Opportunities (PROs), are divided by industry sub sector (production, processing, and transportation/distribution).<sup>5</sup>

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The EPA Natural Gas STAR program offers numerous methods of preventing leaks. These methods, called Best Management Practices (BMPs) and Partnership Reduction Opportunities (PROs), are divided by industry sub sector: production, processing, and transportation/ distribution. Among the practices recommended are:

*Preventive maintenance:* Reduces emissions by improving the overall efficiency of the gas production and distribution system; minimizes the chance of leaks.

*Reduce flashing losses:* As the pressure on the liquid natural gas in a storage tank, well, compressor station, or gas plant drops, some of the lighter compounds dissolved in the liquid are released or “flashed.” Some of the compounds that are liquids at the initial pressure/temperature transform from a liquid into a gas/vapor and are also released or “flashed” from the liquid. The flashed gas can be captured rather than vented to the atmosphere.

*Replace wet seals with dry seals:* Dry seals lead to fewer leaks than wet seals. Dry seals use high-pressure gas to seal the compressor and emit less methane, have lower power requirements, improve compressor and pipeline operating efficiency and performance, enhance compressor reliability, and require significantly less maintenance.

*Compressor rod & ring replacement:* Replacing worn compressor rod packing rings and rods results in operational benefits, reduced methane emissions, and cost savings. Gas leaks from compressor rods represent one of the largest sources of emissions at natural gas compressor stations.

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<sup>5</sup> For a complete list, see <http://www.epa.gov/gasstar/techprac.htm#tabnav>

*Low-bleed, air-based pneumatic devices:* Replacing high-bleed devices with low-bleed devices, retrofitting, and improving the maintenance of high-bleed pneumatic devices are proven approaches to profitably reducing methane emissions. Natural gas emissions from pneumatic control devices are one of the largest sources of methane emissions in the natural gas industry.

*Pump-down techniques prior to maintenance:* Using fixed and portable compressors to lower pipeline pressure prior to maintenance and repair significantly reduces methane emissions and saves money. Pipeline pump-down techniques remove product from the section of pipeline under repair, thereby reducing the volume of natural gas vented to the atmosphere.

*Venting deliquification:* Venting deliquification occurs when natural gas is decompressed from liquid to gas. Some gas escapes to the atmosphere.

**Policy Design:**

The CCAG recommends that New Mexico implement all BMPs, PROs, and available technologies starting in 2007 to reduce overall CO<sub>2</sub>e emissions by ~20% by 2020.

- **Goal levels:** As noted above.
- **Timing:** As noted above.
- **Parties:** Oil and gas production, processing, and transportation/distribution companies

**Implementation method(s):**

Policies to implement these practices could include:

- Information and education.
- Technical assistance.
- Funding mechanisms and/or incentives.
- Voluntary and or negotiated agreements.
- Codes and standards

**Related Policies/Programs in place:**

- Some companies practice the measures outlined above, but currently there is no state or federal requirement for any company to implement any of these practices.

**Type(s) of GHG Benefit(s):**

- CH<sub>4</sub>: This policy could result in substantial reductions of methane emissions in the oil and gas industry.

**Estimated GHG Savings and Costs Per Ton:**

			Reductions (MMTCO <sub>2</sub> e)		
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#	Policy	Scenario	2012	2020	Cumulative Reductions (2007-2020)	NPV (2007–2020) \$ Millions	Cost-Effectiveness \$/tCO2
ES-12	Methane reductions in oil and gas operations through BMPs and PROs	Reduce overall CO2e by ~20% over 2007-2020	2.71	3.43	35.34	-\$360.4	-\$105.37

**Data Sources, Methods and Assumptions (for quantified actions):**

- **Data Sources:** See spreadsheet.
- **Quantification Methods:** See spreadsheet.
- **Key Assumptions:** See spreadsheet.

**Key Uncertainties:**

- See spreadsheet.

**Contributing Issues, if applicable:**

- Proportionally more natural gas would get to market rather than being consumed or lost in the production and distribution process.
- Companies increase their sales, and possibly their profits, by selling rather than wasting valuable product.

**Feasibility Issues, if applicable:**

TBD.

**Status of Group Approval:**

Pending.

**Level of Group Support:**

TBD.

**Barriers to consensus (if less than unanimous consent):**

TBD.

## ES-13 CO<sub>2</sub> Reduction from Fuel Combustion in Oil & Gas Operations

### Policy Description:

*CCAG Summary:* There are a number of ways in which CO<sub>2</sub> emissions in the oil and gas industry can be reduced, including (1) new efficient compressors, (2) optimize gas flow to improve compressor efficiency, (3) improve performance of compressor cylinder ends, (4) capture compressor waste heat, (5) replace compressor driver engines, and (6) waste heat recovery boilers. Policies to encourage these practices include education and information exchange, financial incentives, and mandates or standards that require certain practices.

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

Given the wide range of costs and technologies involved the CCAG identified three key categories: (1) compressor efficiency improvements, (2) waste heat recovery for compressors and boilers, and (3) replacement of gas-driven compressors with electrical generators. Of these three categories, the focus should be efficiency improvements and waste heat recovery. Compressor replacement was considered a less fruitful area for analysis because of the high cost of new compressors relative to the GHG reduction potential (in part because switching the compressor fuel from gas to electricity simply moves the GHG production – at least in part – to another locale).

### Policy Design:

The CCAG recommends that New Mexico focus attention on reducing GHG emissions from fuel combustion in the oil and gas industry through education, financial incentives, or mandates or standards to: (1) improve the efficiency of compressors; (2) boost waste heat recovery for compressors and boilers including the deployment of CHP systems that could sell excess power back to the grid; and to a lesser extent, (3) replace gas-driven compressors with electrical compressors.

- **Goal levels:** Reduce CO<sub>2</sub> emissions from fuel combustion by 75% by 2020 starting in 2007.
- **Timing:** As noted above.
- **Parties:** Oil and gas production, processing, and transportation/distribution companies

### Implementation method(s):

Policies to implement these practices could include:

- Information and education.
- Technical assistance.
- Funding mechanisms and/or incentives.
- Voluntary and or negotiated agreements.
- Codes and standards

**Related Policies/Programs in place:**

- Some companies may practice the measures outlined above, but there is currently no state or federal requirement for any company to implement any of these measures.

**Type(s) of GHG Benefit(s):**

- CO<sub>2</sub>: CO<sub>2</sub> emissions would be reduced directly through the implementation of these measures. Methane emissions would also be reduced, but these are addressed in ES-12.

**Estimated GHG Savings and Costs Per Ton:**

#	Policy	Scenario	Reductions (MMTCO <sub>2</sub> e)			NPV (2007– 2020) \$ Millions	Cost- Effective- ness \$/tCO <sub>2</sub>
			2012	2020	Cumulative Reductions (2007-2020)		
ES-13	CO <sub>2</sub> reduction from fuel combustion in oil & gas operations	Reduce CO <sub>2</sub> emissions by 20% through the use of automated air/fuel ratio controllers on natural gas compressor engines greater than 600 horsepower by 2020.	.225	.585	4.09	-\$48.8	-\$11.93
ES-13	CO <sub>2</sub> reduction from fuel combustion in oil & gas operations	Reduce CO <sub>2</sub> emissions by 25% using organic Rankine cycle CHP systems at natural gas compressor stations.	.281	.731	5.12	\$25.8	\$5.04
ES-13	CO <sub>2</sub> reduction from fuel combustion in oil & gas operations	Reduce CO <sub>2</sub> emissions by 30% by replacing natural gas fired compressor engines with electric compressor motors.	.337	.878	6.14	-\$88.4	-\$14.40

ES-13	CO2 reduction from fuel combustion in oil & gas operations	Sum of the three scenarios above.	.843	2.194	15.29	-\$111.40	-\$7.26
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**Data Sources, Methods and Assumptions (for quantified actions):**

- Data Sources:** U.S. EPA; State of New Mexico; State of Texas; U.S. Climate Change Technology Program; ORMAT International; ControlWorx, LLC; Lazaro et al. (2006) *Strategic Emission Reduction Plan for Stationary Oil and Gas Sources in the Four Corners Region*; Liebowitz and Schochet. (2001) "Generating electric power from compressor station residual heat," *Pipeline and Gas Journal*, November 2001.
- Quantification Methods:** For all three scenarios, the cost/ton of CO2 reduced was initially calculated using data from government and industry. Cost/ton data was extrapolated from the U.S. EPA, state information, supplier data, and supplier data. CO2 reduction goals were established considering (1) the amount of CO2 that could potentially be reduced, (2) availability of technology, (3) cost, and (4) feasibility (with uncertainties noted below). Natural gas savings were factored into the automated air/fuel ratio controller and electric compressor motor installation scenarios based on Mcf savings data from the EPA and suppliers. Net present value was calculated using a 5% annual discount rate of the total overall costs. Cumulative reductions were determined based on linear progress toward meeting the overall reductions for all three scenarios.

Based on field studies of the use of automated air/fuel ratio controllers in the Gulf of Mexico and EPA data, CO<sub>2</sub> reductions from the use of such controllers were estimated to average 230.9 tons/year/engine. Automated air/fuel ratio controllers have been suggested as a best management practice in the San Juan Basin.<sup>6</sup>

Natural gas use savings from the use of an automated air/fuel ratio controller come from more efficient startups, decreased fuel use, and increased production. Average natural gas savings of 78 Mcf/day have reported<sup>7</sup>, as well as increased production rates of between 1% and 6.8%. Fuel savings could yield a payback of as much as \$14,235/year per engine at \$5 Mcf. Additional costs of operating an automated air/fuel controller, which include electricity costs, are reportedly offset by the reduction in engine maintenance costs, according to suppliers.<sup>8</sup> The cost of an automated air/fuel ratio controller was estimated to be \$120,000, based on data provided by the EPA and suppliers.

<sup>6</sup> Lazaro et al. (2006) *Strategic Emission Reduction Plan for Stationary Oil and Gas Sources in the Four Corners Region*.

<sup>7</sup> U.S. EPA. (2004) *Automated air/fuel ratio controllers*. PRO Fact Sheet No. 111.

<sup>8</sup> *Supra*.

Organic Rankine cycle (“ORC”) CHP systems have been used at compressor stations in Canada, and are being developed for compressor stations along the North Border pipeline in North and South Dakota, according to industry reports.<sup>9</sup> They are also in use at landfills in Texas and Illinois, where waste heat from flares and reciprocating internal combustion engines is used to fuel ORC systems, according to the EPA.<sup>10</sup> These systems range from 1-10 MW. The cost of installing an ORC system to generate power was estimated at \$1,000/kW (\$1,000,000/MW), and operation and maintenance costs estimated at \$1/MWh, based on supplier and industry data.<sup>11</sup> Overall cost is estimated at \$40/MWh of output according to suppliers and field studies.<sup>12</sup>

Estimated annual CO<sub>2</sub> reductions using ORC can reach 6,600 tons of CO<sub>2</sub> reduced per MW installed according to suppliers and industry.<sup>13</sup> This could lead to a 6,600 to 66,000 tons/year reduction in CO<sub>2</sub>, depending on the size of the ORC system. Using the midpoint of 36,300 ton/year reduction, this would amount to a \$9.17 cost per ton reduction in CO<sub>2</sub> emissions, assuming a total operating time of 8322 hours, which is based on the reported 95% availability of ORC systems.<sup>14</sup>

For electric compressor motor conversion, the cost of conversion comes from the capital cost and operation and maintenance costs. Estimates indicate capital costs for a 1,000 hp engine to be \$700,000, with around a \$500.00 per day electricity cost according to reports from the state of Texas on the use of electric compressor motors within the state.<sup>15</sup> The use of electric compressor motors has been suggested a best management practice in the San Juan Basin.<sup>16</sup>

Estimated fuel savings are \$1,200/day for a 1,200 hp engine, assuming a natural gas cost of \$5/Mcf. Methane emission reductions are reported to be around 2.11 Mcf per year per horsepower converted for electric engines.<sup>17</sup> The replacement of one 3,000 hp compressor engine with an electric compressor is reported to reduce methane emissions by 6,440 Mcf per year.<sup>18</sup> With an average price of natural gas of \$5/Mcf,

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<sup>9</sup> Liebowitz and Schochet. (2001) “Generating electric power from compressor station residual heat.” *Pipeline and Gas Journal*, November 2001.

Western Area Power Administration. (2005). “Exhaust power provides new resource for Basin Electric.” *Energy Services Bulletin* 24(6). Available online at <http://www.wapa.gov/es/pubs/esb/2005/dec/dec053.htm>.

<sup>10</sup> U.S. Climate Change Technology Program. (2005). *Technology Options for the Near and Long Term*. August 2005.

<sup>11</sup> Liebowitz, H.M. (2002). *Generating Electric Power from Waste Heat using ORC Technology*. Power Point Presentation prepared for PTAC 2002 Climate Change and GHG Technology. H.M. Liebowitz, Manager, Heat Recovery Systems, ORMAT International.

<sup>12</sup> *Supra*.

<sup>13</sup> *Supra*, note 3.

<sup>14</sup> *Supra*, note 5.

<sup>15</sup> Texas Comptroller of Public Accounts. (2004). “East Texas gas company looks to cheaper power solution: Powering the pump.” *Fiscal Notes*, August 2004.

<sup>16</sup> *Supra*, note 1.

<sup>17</sup> U.S. EPA. (2004). *Install electric compressors*. PRO Fact Sheet No 105.

<sup>18</sup> *Supra*.

the cost savings average \$10.55 per year per horsepower converted. The replacement of one 3,000 horsepower gas-fired engine with an electric compressor could save \$32,200/year. Total estimated savings for one 1,000 hp engine are estimated below:

Fuel savings (at \$1/hp/day)	Methane emission reduction savings (at 2.11 Mcf/year/hp)	Total daily savings	Total yearly savings
\$1,000/day	\$28.90/day	\$1,028.90	\$375,548

Projecting from 2007 to 2020, the total estimated savings of replacing one 1,000 hp engine with an electric compressor are shown below:

Costs/year (with capital cost )	Savings/Year	Net Savings/Year
\$236,346	\$375,548	\$146,382

Assuming an emission rate of 56,100 tons CO<sub>2</sub>/Mcf, based on EPA AP-42 factors for reciprocating internal combustion engines, and an average throughput of 10,000 Mcf/year, one 1,000 hp compressor engine can release as much as 5,610 tons/year. A payback of \$26.09 is estimated for every ton of CO<sub>2</sub> reduced when considering estimated savings.

- **Key Assumptions:** It was assumed that the scenarios above represent the most effective approaches to achieving the policy objective of ES-13. This assumption was based on cost, CO<sub>2</sub> reductions, and available data. There may be other effective scenarios, and/or additional information may suggest less effectiveness for above scenarios.

The above estimates above assume a flat production rate until 2020, i.e, that expanded production efforts will balance out declining production from existing fields. A consistent emission rate of 3.9 MMtCO<sub>2</sub>/year was assumed based on emission data for field use of natural gas and natural gas processing included in the reference case forecast prepared by Michael Lazarus. A \$5/Mcf cost for natural gas was used to estimate savings. Consistent costs across equipment types and sizes were assumed for the purposes of this assessment. It was assumed that the technology required for implementing the scenarios above are readily available and readily adaptable to natural gas production in New Mexico. Other assumptions are as noted above.

#### Key Uncertainties:

- For automated air/fuel ratio controllers, it is uncertain exactly how many compressor stations could be equipped with this technology and how many controllers would be required. Data regarding the horsepower, type, location, and grouping of internal combustion engines in New Mexico was not available in time for this analysis.

For ORC CHP systems, it is uncertain how many systems would be required and where such systems would be most feasible and effective. Although baseline research and development appears well-developed, additional research and development costs to specifically apply ORC to facilities in New Mexico may arise.

It is also uncertain what degree of payback may be expected through the sale of electricity from ORC CHP systems.

For electric compressor motors, it is uncertain what level of feasibility exists within the producing areas of New Mexico and how many compressor engines could be cost-effectively replaced. Data on the availability and accessibility of electric power was not available in time for this analysis. It is also uncertain what the potential costs of transmission line and/or substation construction, if any, and increased power generation would be.

Savings may vary depending on future natural gas prices and throughput.

**Contributing Issues, if applicable:**

- Proportionally more natural gas would get to market rather than being consumed or lost in the production and distribution process. This could yield a net payback for producers, producing negative cost/ton results (i.e., savings).
- Some of the criteria air pollutant emissions that would have resulted from less efficient compressors would be eliminated, lowering health impacts and associated health costs.
- Decreased emissions of criteria pollutants could lead to relaxation of throughput and production limits that may exist in permits, leading to corresponding increased in production and profits.
- Operation and maintenance costs may be reduced through the use of electric compressors and automated air/fuel ratio controllers.
- Power generation using ORC CHP systems could yield a payback through the sale of electricity and provide additional power for electric compressor engines.
- Organic Rankine cycle CHP systems do not require water for steam generation and generate no waste, limiting these indirect environmental impacts. Organic Rankine cycle CHP systems may be more feasible than steam driven CHP systems.

**Feasibility Issues, if applicable:**

- Feasibility may depend on the uncertainties as stated above.

**Status of Group Approval:**

Pending.

**Level of Group Support:**

TBD.

**Barriers to consensus (if less than unanimous consent):**

TBD.

## ES-14 GHG Cap & Trade

### Policy Description:

*CCAG Summary: A cap and trade system is a market mechanism in which GHG emissions are limited or capped at a specified level, and those participating in the system can trade permits (a permit is an allowance to emit one ton of CO<sub>2</sub>). By allowing trading, participants with lower costs of compliance can over comply and sell their additional reductions to participants for whom compliance costs are higher. In this fashion, overall costs of compliance are lower than they would otherwise be.<sup>19</sup> Among the important considerations for New Mexico with respect to a cap and trade program are the sources and sectors to which it would apply, the level of the cap, how allocations would be distributed, what offsets would be allowed, and over what region the program would be implemented (e.g., nationally, regionally, etc.), and whether tribally-operated facilities would be included.*

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For every ton of CO<sub>2</sub> released, an emitter must hold a permit. Therefore, the number of permits issued or allocated is, in effect, the cap. The government can give permits away for free according to any one of many different criteria to those participating in the cap and trade system (or even to those who are not), auction them, or some combination of the two. Participants can range from a small group within a single sector to the entire economy, and the compliance obligation can be implemented “upstream” (at the fuel extraction or import level) or “downstream” at points of fuel consumption.

Among the important considerations for New Mexico with respect to a cap and trade program are: the sources and sectors to which it would apply; the level and timing of the cap; how allocations would be distributed (e.g., whether load-based or generation-based, how new market entrants are accommodated, how leakage is addressed, etc.); what if any offsets would be allowed; over what region the program would be implemented (e.g., nationally, regionally, etc.); and whether tribally-operated facilities would be included. Other issues to consider include: which GHGs are covered; whether there is linkage to other trading programs; banking and borrowing; early reduction credit; and what if any incentive opportunities (e.g., interaction with other pollution regulations like

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<sup>19</sup> The Climate Action Team in California recently assembled a good discussion of cap and trade design issues. It can be referenced at: [http://www.climatechange.ca.gov/climate\\_action\\_team/reports/2005-12-08\\_CAP+TRADE\\_REPORT.PDF](http://www.climatechange.ca.gov/climate_action_team/reports/2005-12-08_CAP+TRADE_REPORT.PDF)

Pennsylvania's EDGE program) may be included.

**Policy Design:**

The CCAG recommends that any cap and trade program applicable to New Mexico sources be preferentially implemented on a national or regional (i.e., multi-state) basis.

Economic modeling was conducted within the CCAG process, however, to consider potential GHG reductions and cost ramifications for New Mexico relative to other states under several regional scenarios. This modeling was conducted for the purpose of understanding the impacts of a cap and trade program, not to define the details of a prospective cap and trade regulatory program.

Using the Governor's targets as the cap, the CCAG considered this policy option: (a) on a national basis; (b) over the Western Electric Coordinating Council (WECC) states (subject to minor variations as needed to facilitate analysis); and (c) a sub region of the WECC states selected so as to minimize leakage. Further, the CCAG considered alternative programs covering: (1) all sectors (i.e., an economy-wide approach), and (2) the power sector alone.

- **Goal levels:** As noted above.
- **Timing:** Assess the cap and trade program as starting in 2010.
- **Parties:** As noted above.

**Implementation method(s):**

- Market based mechanism with underlying regulatory obligation.

**Related Policies/Programs in place:**

- No GHG cap and trade program is currently in place in New Mexico or the WECC region.

**Type(s) of GHG Benefit(s):**

- CO2: A cap and trade system is likely to be implemented – at least initially – as a direct limit on CO2 emissions. The level at which the cap is set and how effectively the program addresses leakage risks would determine CO2 reductions.
- CH4, N2O, HFC's, and SFC's could also be reduced under a cap and trade program, which covers multiple GHGs.
- Black Carbon: To the extent that generation from coal and oil would decline under a cap and trade system, black carbon emissions would also decrease.

**Estimated GHG Savings and Costs Per Ton:**

			<b>Reductions (MMTCO2e)</b>		
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#	Policy	Scenario	2012	2020	Cumulative Reductions (2007-2020)	NPV (2007–2020) \$ Millions	Cost-Effectiveness \$/tCO2
ES-14	GHG Cap and Trade Program	National/NEMS: 2.4%–2.8% Carbon Intensity (CI) improvement per year, with a \$6.16–\$9.86 safety valve	-0.1	1.0	3.6	\$25	\$7
ES-14	GHG Cap and Trade Program	National/NEMS: 2.6%–3.0% CI, \$8.83–\$14.13 safety valve	0.1	1.0	4.2	\$42	\$10
ES-14	GHG Cap and Trade Program	National/NEMS: 2.8%–3.5% CI, \$22.09–\$35.34 safety valve	-0.1	8.1	31.3	\$541	\$17
ES-14	GHG Cap and Trade Program	National/NEMS: 3.0%–4.0% CI, \$30.92–\$49.47 safety valve	0.1	9.1	43.5	\$804	\$19
ES-14	GHG Cap and Trade Program	Rose: 11-State Economy-wide C&T; 5% costless	6.7 <sup>20</sup>	10.9 <sup>21</sup>	90.6 <sup>22</sup>	\$280 <sup>23</sup>	\$3
ES-14	GHG Cap and Trade Program	Rose: 11-State Economy-wide C&T; 15% costless	10.3 <sup>24</sup>	14.9 <sup>25</sup>	132.0	-\$488	-\$4
ES-14	GHG Cap and Trade Program	Rose: 11-State Power-Sector C&T; 5% costless	2.926	5.427	42.5	\$328	\$8
ES-14	GHG Cap and Trade Program	Rose: 4-State Economy-wide C&T; 5% costless	5.728	9.429	78.1	\$413	\$5

<sup>20</sup> See Adam Rose spreadsheet “S\_5% Case NPV1” – “Emission Reduction” Table

<sup>21</sup> See Adam Rose spreadsheet “S\_5% Case NPV1” – “Emission Reduction” Table

<sup>22</sup> Per Adam Rose’s 8/6/06 email of S/5%/2020 with 2006 NPV. See spreadsheet “S\_5% Case NPV1”

<sup>23</sup> Per Adam Rose’s 8/6/06 email of S/5%/2020 with 2006 NPV. See spreadsheet “S\_5% Case NPV1”

<sup>24</sup> TABLE AS/15%/2012, page 7.

<sup>25</sup> TABLE BS/15%/2020, page 9.

<sup>26</sup> TABLE AP/5%/2012, page 11.

<sup>27</sup> TABLE BP/5%/2020, page 12.

<sup>28</sup> TABLE A’S/5%/2012, page 13.

<sup>29</sup> TABLE B’S/5%/2020, page 14.

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

- Note: Explanation of the data, methods, and assumptions utilized in quantifying the WECC-area and WECC-subset geographical scenarios is contained in an accompanying paper, *Economic Analysis of a Cap and Trade System for Carbon Dioxide Emission Reduction in the Western States*, by Adam Rose and Dan Wei, Preliminary Draft, August 4, 2006.
- **Data Sources:** Data for the national electricity modeling done in this analysis comes from the US Energy Information Administration (EIA) and can be found within the National Energy Modeling System (NEMS). Data in NEMS includes representation of the existing generation, transmission and distribution system down to the unit level. NEMS also includes data that characterizes new plants that the model can choose to build to meet projected demand growth. EIA publishes Assumptions to the Annual Energy Outlook that details key assumptions in the current version of the model. EIA also publishes NEMS model documentation.
- **Quantification Methods:** The national modeling presented here was done by the Energy Information Administration in a Congressional Service Report from March 2006 entitled “Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals.” The scenarios listed are for four national cap and trade policies. We scaled the impacts to approximate results in New Mexico for the four scenarios presented here in the same way that we analyzed the NEMS modeling done specifically for this process. For the cap and trade scenarios, we approximated the cost of the policies by multiplying CO<sub>2</sub> reductions by one-half of the market price for CO<sub>2</sub> allowances. (The allowance price is the marginal price of allowances needed to produce the reported emission reductions; the actual cost of each ton of reductions ranges from zero up to the price of allowances. For simplicity, we assume that the actual cost is an average of the high (market clearing price) and low (zero) cost of reductions, which equals one-half of the market clearing price). We report costs as a net present value of the stream of costs from 2006 – 2020. We found the number of tons reduced by taking the difference between the emissions in the policy case and a reference case NEMS run. Because the NEMS model is a national model with multi-state regions (New Mexico is within the Rocky Mountain Power Area), the results for New Mexico were derived from results in the region. We shared out the regional emission and cost results according to the share of New Mexico generation within the region.
- **Key Assumptions:** Any analysis of state-level policies using the National Energy Modeling System (NEMS) from the US Energy Information Administration should be weighed carefully. NEMS is a national model that consists of 13 regions. State policies cannot be implemented explicitly within NEMS, and the state-specific impacts cannot be known explicitly. We must make assumptions about the impact of policies at the state level by sharing out regional results.

### Key Uncertainties:

- As with any assessment of the future, this analysis has many uncertainties. Key uncertainties are those related directly to the assumptions and quantification methods noted above. If those assumptions are incorrect, then the results would change. Other uncertainties include the forecast of the price of fossil fuels and the growth in the demand for electricity.

**Contributing Issues, if applicable:**

- The shift from fossil fuel generation which could result from a GHG cap and trade program would lead to reductions in criteria air pollutants and, consequently, reduce health impacts and associated health costs.
- Allowing “offsets” from outside the capped sector(s) would create an incentive to quantify and reduce GHG emissions from sources in other sectors.

**Feasibility Issues, if applicable:**

- The CCAG has consistently expressed grave feasibility concerns about a cap and trade program implemented solely within New Mexico.
- Any cap and trade program for New Mexico should account for and incorporate sources that are currently subject to substantially different regulatory regimes (e.g., traditional, tribal, and co-ops).

**Status of Group Approval:**

Pending.

**Level of Group Support:**

TBD.

**Barriers to consensus (if less than unanimous consent):**

TBD.

## ES-15 Generation Performance Standard

### Policy Description:

*CCAG Summary:* A generation performance standard (GPS) is typically a requirement that electricity utilities or load serving entities (LSE) sell electricity with an average emission rate below a specified mandatory standard. Utilities must take action to ensure that their generation mix meets the standard.

A generation performance standard (GPS) is typically a requirement that electricity utilities or load serving entities (LSE) sell electricity with an average emission rate below a specified mandatory standard. Utilities must take action to ensure that their generation mix meets the standard.

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

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

### Policy Design:

The CCAG recommends that New Mexico develop a GPS applicable only to new generation (both to meet demand growth as well as to replace retiring generation capacity). The GPS level would be equivalent to GHG emissions from a new natural gas combined cycle plant. Assessment of this option should consider that new electricity demand might be served, at least in part, by out-of-state resources.

- **Goal levels:** Set a GPS equivalent to a new natural gas combined cycle plant applicable to new supply, whether generated in New Mexico or imported.
- **Timing:** As new generation capacity is built or power is imported.
- **Parties:** Utilities (electricity generators).

### Implementation method(s):

- Codes and standards.
- Market-based mechanisms with underlying regulatory obligation.

### Related Policies/Programs in place:

- No GPS system is in place in New Mexico.

**Type(s) of GHG Benefit(s):**

- CO<sub>2</sub>: A GPS program is typically a direct limit on CO<sub>2</sub> emissions. The level of the standard would determine CO<sub>2</sub> reductions.
- CH<sub>4</sub>, N<sub>2</sub>O, HFC's, and SFC's could also be reduced under a GPS program, which covers multiple GHGs.
- Black Carbon: To the extent that generation from coal and oil would decline under a GPS program, black carbon emissions would also decrease.

**Estimated GHG Savings and Costs Per Ton:**

#	Policy	Scenario	Reductions (MMTCO <sub>2</sub> e)			NPV (2007– 2020) \$ Millions	Cost- Effective- ness \$/tCO <sub>2</sub>
			2012	2020	Cumulative Reductions (2007-2020)		
ES-15	Generation Performance Standard	All new supply (generated or imported) must be as clean as NGCC	1.2	3.8	24.3	\$522	\$21

**Data Sources, Methods and Assumptions (for quantified actions):**

- **Data Sources:** CDEAC, WECC, EIA, EPA, NREL.
- **Quantification Methods:** The analysis uses a spreadsheet tool to compare the costs and CO<sub>2</sub> emissions of compliance with the GPS with the costs and CO<sub>2</sub> emissions of the reference case. It involves the following steps: (1) estimate the amount of new coal generation expected in the reference case; (2) calculate the amount of CO<sub>2</sub> emissions from the new coal generation that would exceed the generation performance standard; (3) identify the type and amount of gas and renewable generation that would be needed to offset those coal CO<sub>2</sub> emissions; and (4) estimate the extent to which the cost of the gas and renewable generation exceeds the cost of conventional generation.
- **Key Assumptions:** Where applicable, the key assumptions are the same as those used in assessing the RPS (ES-1). The type of replacement resources needed to comply with the GPS are based on the mix of renewable generation that is assumed for the RPS analysis, modified to account for the role that gas can play in meeting the GPS. It is assumed that in 2010 the replacement resource mix is 50% gas and 50% wind, and that in 2020 the replacement mix is 50% gas, 40% wind and 10% biomass. The cost assumptions for the new renewable systems are the same as those described above for ES-1. The avoided costs associated with this policy are equal to the

levelized cost of a new coal power plant, which is estimated to be \$41/MWh using assumptions from a recent EPA report, as described for ES-6.<sup>30</sup> Additional detail on key assumptions is provided in Attachments A and B below.

**Key Uncertainties:**

- As with any assessment of the future, this analysis has many uncertainties. Key uncertainties are those related directly to the assumptions and quantification methods noted above. If those assumptions are incorrect, then the results would change. Other uncertainties include the forecast of the price of fossil fuels and the growth in the demand for electricity.

**Contributing Issues, if applicable:**

- TBD

**Feasibility Issues, if applicable:**

- TBD

**Status of Group Approval:**

Pending.

**Level of Group Support:**

TBD.

**Barriers to consensus (if less than unanimous consent):**

TBD.

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<sup>30</sup> Environmental Protection Agency, *Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies*, July 2006.

## ES-16 Regulatory Reform for Electric Cooperatives

### Policy Description:

As member-owned entities, electric cooperatives are often not considered to be bound by the same regulatory bargain as investor-owned utilities (IOUs). The latter enjoy monopoly status in the marketplace along with a guaranteed rate of return in exchange for close regulatory oversight to protect customers from undue market power. Electric cooperatives are not seen as requiring similar regulatory oversight because their customers (coop members) are also owners and thus have an alternative regulatory mechanism available, i.e., election of their Boards of Directors.

As a result of this key regulatory difference, electric cooperatives are often not subject to the same regulations as IOUs, including state environmental regulations. (They are subject to federal environmental regulations.) Accordingly, the CCAG believes that it is worth considering limited reform of these provisions so that electric cooperatives face equivalent GHG reduction requirements as IOUs.

### Policy Design:

Unless otherwise indicated, the analysis of all ES policy options addresses generation statewide, and thus includes electricity generated at tribally owned or operated facilities and at electric cooperatives. While the CCAG remains cognizant that final implementation of ES policy options is likely to vary among IOUs, tribal facilities, and cooperatives, this approach allows policy options to be considered equally across the board. Accordingly, the CCAG recommends this policy option as a non-quantified *enabling policy* for the electric cooperative-related GHG emission reductions and costs that are already quantified in the ES policy options. To include GHG reductions and costs under specific ES policy options as well as under this generic enabling policy would double-count the associated GHG reductions and costs.

- **Goal levels:** Not applicable to an enabling policy.
- **Timing:** Efforts to implement this enabling policy should proceed as rapidly as possible.
- **Parties:** Electric cooperatives.

### Implementation method(s):

- Legislation – Regulatory reform of electric cooperatives with respect to environmental issues is likely to require statutory change.

### Related Policies/Programs in place:

- Electric cooperatives in New Mexico are currently subject to less or no PRC oversight as compared to investor-owned utilities.

**Type(s) of GHG Benefit(s):**

- CO2: To the extent that generation from coal and oil would decline as a result of regulatory reform of electric cooperatives, CO2 emissions would decrease.
- Black Carbon: To the extent that generation from coal and oil would decline as a result of regulatory reform of electric cooperatives, black carbon emissions would also decrease.

**Estimated GHG Savings and Costs Per Ton:**

Not applicable.

**Data Sources, Methods and Assumptions (for quantified actions):**

Not applicable.

**Key Uncertainties:**

- Specific reforms necessary to enable full implementation of the CCAG's selected policies will require a thorough legal review and investigation after the CCAG's policy recommendations are finalized.

**Contributing Issues, if applicable:**

- Any shift from fossil fuel generation that would result from regulatory reform of electric cooperatives would lead to reductions in criteria air pollutants and, consequently, health impacts and costs associated with those pollutants.

**Feasibility Issues, if applicable:**

Not applicable.

**Status of Group Approval:**

Pending.

**Level of Group Support:**

TBD.

**Barriers to consensus (if less than unanimous consent):**

TBD.