Attachment H-6

ES-12 Methane Reductions in Oil and Gas Operations (BMPs & PROs) – Summary of Initial Quantification of GHG Savings and Cost per Ton

The following is a summary of an initial analysis developed by Dr. Lorna Greening to assist in the Energy Supply Technical Work Group's consideration of ES-12. Full details can be found in an accompanying comprehensive spreadsheet. Additional investigation and analysis regarding methane reduction opportunities in oil and gas operations should be conducted to refine and improve this analysis in order to determine GHG reductions, costs or savings, and feasibility associated with reducing methane emissions in oil and gas operations.

The oil and gas participants on the TWG do not agree that the analysis conducted is accurate and reflects correct potential reductions or costs.

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-12	Methane reductions in oil and gas operations through BMPs and PROs	Reduce overall CO2e by ~20% over 2007-2020	2.7	3.4	35.3	-$360.4	-$105

ES-12 Initial Analysis: Summary of Results					
Analysis conducted by Dr. Lorna Greening	Reductions (MMTCO2e)		Cumulative Reductions 2007-2020	NPV (2007-2020) $Millions	Cost-Effectiveness $/tCO2e
	2012	2020			
Distribution					
High with low reduction scenario	0.12	0.14	1.60	-$20.40	-$142.07
Low with high reduction scenario	0.13	0.14	1.64	-$20.02	-$141.92
Transportation					
High with low reduction scenario	0.36	0.62	5.04	-$31.56	-$50.61
Low with high reduction scenario	0.44	0.49	5.56	-$36.49	-$75.00
Gas Processing					
High with low reduction scenario	0.28	0.35	3.66	-$17.56	-$50.48
Low with high reduction scenario	0.28	0.24	3.42	-$15.77	-$65.51
Production					

High with low reduction scenario	1.78	2.35	23.42	-$272.24	-$116.05
Low with high reduction scenario	2.02	2.52	26.33	-$306.70	-$121.67
Overall					
High with low reduction scenario	2.54	3.46	33.72	-$341.76	-$100.39
Low with high reduction scenario	2.87	3.39	36.95	-$378.98	-$110.35
Midpoint of the above two scenarios	2.71	3.43	35.34	-$360.37	-$105.37

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

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

Key Uncertainties:

- See spreadsheet for details.

Attachment H-7

ES-12 Methane Reductions in Oil and Gas Operations (BMPs & PROs) – Spreadsheet for Initial Quantification of GHG Savings and Cost per Ton

Full details of the initial analysis developed by Dr. Lorna Greening to assist in the Energy Supply Technical Work Group's consideration of ES-12 can be found in an accompanying comprehensive spreadsheet. Additional investigation and analysis regarding methane reduction opportunities in oil and gas operations should be conducted to refine and improve this analysis in order to determine GHG reductions, costs or savings, and feasibility associated with reducing methane emissions in oil and gas operations.

Dr. Lorna Greening initial spreadsheet analysis can be accessed electronically at http://www.nmclimatechange.us/template.cfm?FrontID=4705 (labeled as Attachment H-7).

Attachment H-8

ES-13 CO2 Reductions from Fuel Combustion in Oil and Gas Operations – Preliminary Quantification of GHG Savings and Cost per Ton

With little industry data and time available, the following cursory analysis was developed by Mr. Jeremy Nichols to assist in the Energy Supply Technical Work Group's consideration of ES-13. Due to these limitations and current uncertainties regarding costs and emission reduction benefits of these and other potential approaches to reduction CO2 from field operations, a comprehensive and thorough estimation of GHG savings and costs (or savings) per ton could not be provided at this time. These limitations, and others as appropriate, will be addressed by the NMED-led study recommended by the CCAG in ES-13.

The oil and gas participants on the TWG do not believe the analysis conducted by Jeremy Nichols is accurate, reflects feasible technologies, or reflects potential opportunities associated with engines located in New Mexico.

Estimated GHG Savings and Costs Per Ton:

#	Policy	Scenario	Reductions (MMTCO2e)			Preliminary	Preliminary
			2012	2020	Cumulative Reductions (2007-2020)	NPV (2007–2020) $ Millions	Cost-Effective-ness $/tCO2
ES-13	CO2 reduction from fuel combustion in oil & gas operations	A. Reduce CO2 emissions by 20% through the use of automated air/fuel ratio controllers on natural gas compressor engines greater than 600 horsepower by 2020.	.3	.6	4.7	-52.9	-$11
ES-13	CO2 reduction from fuel combustion in oil & gas operations	B. Reduce CO2 emissions by 25% using organic Rankine cycle CHP systems at natural gas compressor stations.	.3	.8	5.9	28.0	$5
ES-13	CO2 reduction from fuel combustion in oil & gas operations	C. Reduce CO2 emissions by 30% by replacing natural gas fired compressor engines with electric compressor motors (assuming zero-carbon electricity).	.4	1.0	7.1	-95.5	-$13

ES-13	**CO2 reduction from fuel combustion in oil & gas operations**	**Combination of A, B, and C technology options above.**	**1.0**	**2.4**	**17.7**	**-120.5**	**-$7**
ES-13	**CO2 reduction from fuel combustion in oil & gas operations**	**Combination of A and B technology options above.[42] (See Attachment H-9)**	**0.6**	**1.4**	**10.6**	**-24.9**	**-$2**

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_2 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.[43]

  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

[42] Omission of ES-13 Scenario C from this total reflects the concern raised in Attachment H-9 that replacing natural gas fueled compressors at this time may not reduce CO2 emissions because of the current carbon intensity of grid average electricity in New Mexico.

[43] Lazaro et al. (2006) *Strategic Emission Reduction Plan for Stationary Oil and Gas Sources in the Four Corners Region*.

savings of 78 Mcf/day have reported[44], 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.[45] The cost of an automated air/fuel ratio controller was estimated to be $120,000, based on data provided by the EPA and suppliers.

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.[46] 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.[47] 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.[48] Overall cost is estimated at $40/MWh of output according to suppliers and field studies.[49]

Estimated annual CO_2 reductions using ORC can reach 6,600 tons of CO_2 reduced per MW installed according to suppliers and industry.[50] This could lead to a 6,600 to 66,000 tons/year reduction in CO_2, 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_2 emissions, assuming a total operating time of 8322 hours, which is based on the reported 95% availability of ORC systems.[51]

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.[52] The use of electric compressor motors has been suggested a best management practice in the San Juan Basin.[53]

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[44] U.S. EPA. (2004) *Automated air/fuel ratio controllers*. PRO Fact Sheet No. 111.
[45] *Supra*.
[46] 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.
[47] U.S. Climate Change Technology Program. (2005). *Technology Options for the Near and Long Term*. August 2005.
[48] 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.
[49] *Supra*.
[50] *Supra*, note 3.
[51] *Supra*, note 5.
[52] Texas Comptroller of Public Accounts. (2004). "East Texas gas company looks to cheaper power solution: Powering the pump." *Fiscal Notes*, August 2004.
[53] *Supra*, note 1.

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.[54] 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.[55] With an average price of natural gas of $5/Mcf, 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 CO2/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_2 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, CO2 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 MMtCO2/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

[54] U.S. EPA. (2004). *Install electric compressors*. PRO Fact Sheet No 105.
[55] *Supra*.

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 also vary depending on future natural gas prices and throughput.

Attachment H-9

ES-13 CO2 Reductions from Fuel Combustion in Oil and Gas Operations – Preliminary Analysis of CO2 Emissions from Natural Gas Fueled vs. Electrically Powered Compressors

The following preliminary analysis was developed by Mr. G. Reid Smith to assist in the Energy Supply Technical Work Group's consideration of ES-13. Its conclusion suggests that compared to grid average CO2 emissions per kWh at the present time, fueling a mid-size compressor engine (Caterpillar 3508) with natural gas may result in 32% less CO2 emissions. Similar analyses should be conducted for other size engines and may corroborate this conclusion. Updated emissions information reported by the Natural Resource Defense Council shows "grid average" CO2 emissions of 1.491 lbs/kwh and 1.717 lbs/kwh for PNM and Excel respectively (not restricted to New Mexico) - both of which represent improvement over the 2.02 lbs/kwh figure below, but which remain above the 1.366 lbs/kwh calculated for an engine fueled by natural gas. This may suggest that, at this time, replacement of gas fired engines with electrically driven compressors is a poor idea from a carbon standpoint.

ES-13 Preliminary Analysis of CO2 Emissions from Natural Gas Fueled vs. Electrically Power Compressors				
A.	New Mexico Average Electric Generation; **CO2 lbs/kwh** (Source: EIA, *Updated State-level Greenhouse Gas Emission Coefficients for Electricity Generation 1998-2000*)			2.02
B.	Cat G3508 LE Fuel Usage; BTU/kwh (Source: Derived below as illustrated.)			10,710
C.	Methane; BTU/SCF (Net heating value, i.e., usable BTUs)			909.4
D.	Cat G3508 LE Fuel Usage SCF/kwh (Source: Derived below as illustrated.)			11.777
E.	Cat G3508 LE **CO2 lbs/kwh** (Source: Derived below as illustrated.)			1.366
Derivations:				
F.	11.3	MJ/kwh	From Cat Specification Sheet	
G.	947.82	Btu/MJ	From Google "on-line" conversion tool	
H.	10,710.348	BTU/kwh	Row F time Row G	
I.	11.78	SCF/kwh derived for G3508 LE	Row H divided by Row C	
J.	379.48	SCF/mole		
K.	16.01	MW - methane		
L.	44	MW - CO2		
M.	0.497	lbs methane/kwh		
N.	1.366	lbs CO2/kwh (the ratio of MW's times the methane lbs/hr)	(Row L divided by Row K) time Row M	
Conclusion:				
O.	CO2 Intensity Ratio: Natural Gas Fired Engine to Electric Driven Engine		Row E divided by Row A	**0.68:1**