Appendix I
Oil and Gas
Policy Recommendations

Summary List of Alaska Climate Change Mitigation Policy Recommendations

Policy No.	Policy Recommendations	GHG Reductions ($MMtCO_2e$)				Net Present Value (million 2009$)	Cost-Effective-ness (2009$ /tCO_2e)	Level of Support
		2015	2020	2025	Total 2010-2025	2010–2025		
OG-1	Best Conservation Practices	*Not Quantified*						Unanimous
OG-2	Reductions in Fugitive Methane Emissions	0.2	0.2	0.2	3.2	$181.4	$57	Unanimous
OG-3	Electrification of North Slope Oil and Gas Operations, With Centralized Power Production and Distribution	—	3.0	4.4	26.6	$7,791.0	$293	Unanimous
OG-4	Improved Efficiency Upgrades for Oil and Gas Fuel-Burning Equipment	0.5	2.1	2.1	19.7	$1,600.1	$81	Unanimous
OG-5	Renewable Energy Sources in Oil and Gas Operations	0.7	0.7	0.7	8.0	$2,603.4	$327	Unanimous
OG-6	Carbon Capture (From North Slope High-CO_2 Fuel Gas) and Geologic Sequestration With Enhanced Oil Recovery	—	0.9	0.9	7.8	$1,368.8	$176	Unanimous
OG-7	Carbon Capture (From Exhaust Gas at a Centralized Facility) and Geologic Sequestration With Enhanced Oil Recovery	—	1.8	1.8	16.1	$3,094.1	$192	Unanimous
OG-8	Carbon Capture (From Exhaust Gas) and Geologic Sequestration Away From Known Geologic Traps	0.7	0.7	0.7	8.0	$7,937.7	$994	Unanimous
	Sector Total Before Adjusting for Overlaps	**9.4**	**10.8**	**89.4**	**2.1**	**$24,576.5**		
	Sector Total After Adjusting for Overlaps	TBA	TBA	TBA	TBA	TBA		
	Reductions From Recent Actions (CAFE Standards)	**0**	**0**	**0**	**0**	**0**		
	Sector Total Plus Recent Actions							

NOTES:

These represent the best set of options available for reducing GHG emissions in the Oil and Gas Sector. They are recommended to the Climate Change Sub-Cabinet for further study.

Policies were modeled on generic, publicly available industry data from North Slope oil and gas operations. Thus, the results must only be used to help direct more precise modeling, which would include, for example, taxes, royalties, individual oil and gas facility data, and specific engineering studies.

'"Net Present Value" used in the summary table above would be regarded in the oil and gas industry as "Net Present Cost." Positive numbers in the two right-hand columns indicate that an investment in the policy would generate a financial loss.

"Net Present Value" and "Cost-Effectiveness" values do not apply in Cook Inlet or any other oil and gas basin, due to vastly different production life, geographic distribution, and physical constraints.

Due to the analytical methodology, "Cost Effectiveness" is likely lower than the break-even cost of carbon needed to make a project economically feasible.

None of the modeling included the impact of short-term production loss to implement the policies OG-2 though OG-7.

These policies are technology-based opportunities for reducing greenhouse gas emissions (GHG), not policies to be directly implemented by Alaska.

The GHG savings estimates presented here are not additive. Policies have significant, sometimes complete, overlap in targeted GHG emissions.

CAFE = corporate average fuel economy; CO_2 = carbon dioxide; GHG = greenhouse gas; MMtCO_2e = million metric tons of carbon dioxide equivalent; \$/tCO_2e = dollars per metric ton of carbon dioxide equivalent; OG = oil and gas.

Overarching Considerations

On a broader scale, the following overarching considerations are recognized as critical to maximizing the implementation efficiency of any GHG reduction project:

- Evaluate how possible federal GHG reduction programs, such as cap and trade, a carbon tax, and/or command and control, could impact the oil and gas (O&G) industry in Alaska.
- Engage in the national debate on GHG reduction to craft a program that ensures the economic vitality of Alaska's O&G sector, and allows for increased production from the state's untapped O&G resources.
- Ensure any emission reductions in the Alaska O&G sector are creditable toward a federal program, because there are limited reduction opportunities.
- Do not preempt the federal legislation and rulemaking. The federal government will impose GHG regulations and requirements independent of Alaska, so state actions in this regard will be redundant and will serve only to impose regulatory confusion and to increase compliance costs (two separate GHG reporting regimes, two separate cap-and-trade tracking mechanisms, etc).
- Fugitive emission reporting will be required pursuant to new rules proposed by the U.S. Environmental Protection Agency (EPA). These regulations are a first step in a federal GHG regulatory program. O&G companies will comply with these regulations as they come into effect.
- Ensure up-front planning for budget, staffing, etc.

- Consider net environmental benefits for GHG reduction projects, where there are potential trade-offs between currently regulated pollutants and GHGs (e.g., between nitrogen oxides [NO_X] and carbon dioxide [CO_2]).
- Consider streamlined permitting that allows expediting permits for projects that offer GHG emission reductions.
- Use this information to inform policymakers.

OG-1. Best Conservation Practices

Policy Description

This policy recommends the state via communication efforts enhance companies' ongoing efforts to reduce greenhouse gas (GHG) emissions using common-sense measures that minimize fuel consumption. Specific initiatives are already being developed to suit the needs of specific conservation opportunities. Such initiatives/opportunities include (but are not limited to):

- Reduce consumption of liquid fuel at/in support of North Slope oil fields;
- Minimize the fuel required for operation of flares;
- Optimize the existing process to minimize energy consumption;
- Reduce miles driven and flown by employees and contractors; and
- Cut electricity use in offices and camps.

Policy Design

The policy reduces carbon emissions by decreasing the amount of fuel used to support O&G operations in Alaska. It is largely behavior-based and is achieved by ongoing encouragement to individuals in making good conservation choices and, through repetition, for those choices to become habits. The policy does not require large capital projects to accomplish its goals.

Goals:

- Encourage the O&G workforce in continued energy conservation efforts;
- Ensure that companies' ongoing efforts are creditable under any future GHG regulatory programs.

Timing:

- Alaska should immediately begin efforts to enhance communication on best practices.
- Alaska should currently be trying to influence any programs on the federal level to ensure the companies' ongoing efforts are creditable under proposed GHG regulations.

Parties Involved: North Slope & Cook Inlet producers, Alaska Department of Environmental Conservation (DEC), GreenStar, or some other third party to encourage communication of best practices between producers.

Other: None.

Implementation Mechanisms

The policy would be implemented through companies' internal workforce outreach programs to share best practices for reducing fuel consumption. Sharing best practices and individual and organizational recognition programs could be developed through the GreenStar program, the State of Alaska Web site, and/or North Slope producer Intranet sites.

Related Policies/Programs in Place

Conservation efforts already under way:

- Increased the number of bull rails available for plugging in vehicles during cold weather.
- Powered well pads sufficient to run drill rigs on field electrical grids, reducing diesel fuel use.
- Converted diesel-fired equipment to gas-fired equipment.
- Converted the Prudhoe Bay fleet to more fuel-efficient vehicles.
- Implemented education programs to turn off lights when not in use and to encourage the use of fluorescent bulbs where feasible.
- Encouraged employees to reduce the number of trips taken by vehicle or aircraft.
- Implemented an energy management team.
- Right-sized equipment to smaller sources.
- Reduced fuel gas utilization through process optimization.
- Moved Chevron's Anchorage office to an energy-efficient Leadership in Energy and Environmental Design (LEED)-certified building.
- Participate in the GreenStar program to coordinate similar efforts.
- DEC and the Municipality of Anchorage have successfully performed similar outreach to encourage use of block heaters.

Types(s) of GHG Reductions

Fuel combustion-related emissions (CO_2) reduced.

Estimated GHG Reductions and Net Costs or Cost Savings

Not quantified, but efforts are expected to be at least cost-neutral.

Key Uncertainties

None known.

Additional Benefits and Costs

Benefits: This policy will result in near-term reductions of carbon emissions, as well as emissions of conventional pollutants.

Costs: It is believed no additional State of Alaska budget is necessary to implement. Costs to O&G producers in Alaska will be modest and will vary by initiative.

Feasibility Issues

No regulatory mechanisms are proposed. There are no significant feasibility issues with implementation of this option. Conservation efforts will need to be tempered by operational integrity and life safety issues, particularly on the North Slope.

Status of Group Approval

Approved.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

OG-2. Reductions in Fugitive Methane Emissions

Policy Description

Fugitive methane emissions are defined as unintentional releases of methane to the atmosphere, such as leaks from valves, flanges, unions, tube fittings, or buried pipe. In addition, common practice includes emissions related to compressor wet seals. This policy recommends studies on both types of emissions. The quantification modeling covers both fugitives and emissions related to wet seals on the North Slope.

This policy relates to the technical and economic feasibility of reducing fugitive and wet seal emissions by first determining where leaks occur, and then planning the optimal corrections. Steps for this determination are:

- Begin official refinements to fugitive methane inventories developed by DEC and the Center for Climate Strategies in 2006–2007 (current inventories dramatically overestimate the fugitive emissions). A more recent study by ICF International provides a more realistic estimate of +/–0.16–0.32 million metric tons of carbon dioxide equivalent per year ($MMtCO_2e$/yr).[1]
- Assess potential reductions and associated costs to reduce fugitive methane emissions.

Policy Design

Goals:

- Initiate studies immediately on the technical and economic aspects of implementation. Include in the economic analysis the design of appropriate financial incentives to encourage capital investments as identified by gross quantification model results.
- Review current leak detection procedures and update as needed. Alaska should participate in the federal legislative and rulemaking process by commenting on and providing input to the reporting rules proposed by Congress and EPA.

Timing: Studies could begin immediately.

Parties Involved: Unit operators, State of Alaska.

Other:

Geographic Focus: On the North Slope and in Cook Inlet, where feasible technically and economically on a project-by-project basis. The North Slope and Cook Inlet must be evaluated separately, as the economic considerations are different between the two geographic areas. As most O&G emissions are associated with facilities located on the North Slope, the biggest potential savings in GHG emissions are there.

The quantification modeling of this policy focused on the North Slope only. If Cook Inlet were to be included in an evaluation, the economic and technical feasibility should be reviewed independently from the North Slope operations. Cook Inlet O&G production is nearing the end of usable production life for the known fields. That and its geographic distribution and physical constraints result in an economic analysis for reducing GHG emissions very different from the economic analysis for reducing GHG emissions on the North Slope.

Implementation Mechanisms

Industry and the state should work together to evaluate emission reductions and initiate studies to recommend the best way forward to economically reduce fugitive emissions due to wet seals.

Related Policies/Programs

Potential federal cap-and-trade legislation and EPA air quality regulations.

Types(s) of GHG Reductions

Reduce methane leakage by finding and fixing leaks, and by reducing the emissions related to wet seals.

Estimated GHG Reductions and Net Costs or Cost Savings

The model predicts a \$57/metric ton (t) cost for reduction of fugitive emissions and wet seal upgrades. The estimate for expected yearly reduction in CO_2 emissions is 0.235 $MMtCO_2e$, and the estimate for the total reduced emissions through 2025 is 3.2 $MMtCO_2e$.

Data Sources: EPA, American Petroleum Institute (API), tools available to ICF International, and the best professional judgment of the O&G Technical Work Group (TWG) members.

Quantification Methods: Policy options were modeled on generic, publicly available industry data from North Slope oil and gas operations. Thus, results must only be used to help direct more precise modeling, which would include, for example, taxes, royalties, individual oil and gas facility data, and specific engineering studies. Used a ground-up, first principles approach. Quantification facilitated by ICF International. Current emissions estimated using ICF International study. Bottom-up costs were estimated for each defined step from field experiences and literature, allowing some comparison and confirmation to similar independent studies—e.g., Intergovernmental Panel on Climate Change, etc.

Quantification assumes replacement of wet seals with dry seals over 4 years. Alternative methods of reducing emissions, such as capturing and flaring the methane, are viable, but are not modeled.

Key Assumptions:

- All quantification assumes static activity based on 2008 production data.
- The cost of natural gas until a gas pipeline is built is \$0 per thousand standard cubic feet (Mscf).
- The wellhead cost of natural gas after a pipeline is built (assumed 2019) is \$6/Mscf, and sensitivities were run at \$2, \$4, and \$6/Mscf.
- Cost of carbon = \$0/t.

- Capital and operating costs were amortized to 2035.
- A 5% discount rate was modeled. The cost-effectiveness estimates reported here are consistent with the methodology adopted by the MAG for all TWGs involved in this process. The estimates can be interpreted as a rough indication of the "social" cost per ton of emissions reduced, and so can be used to rank and compare different abatement options within and across the sector TWGs for policy purposes. However, an estimate of the carbon price at which abatement would first become profitable could be higher than the cost-effectiveness modeled here. The cost-effectiveness estimates are calculated using a lower discount rate than is typically used by industry in determining the profitability of investments, and do not discount emission reductions. Consequently, the modeling may not accurately reflect the industry break-even price. Other factors, such as capital depreciation, would also alter the calculation. See EPA's methodology for calculating break-even prices, available at http://www.epa.gov/methane/pdfs/methodologych4.pdf.

Key Uncertainties

Fugitive methane emission estimates are preliminary and based on limited data. The EPA GHG reporting rule will ensure better accuracy in emission estimates, as well as improve estimates of the costs associated with GHG reductions.[1]

Additional Benefits and Costs

Implementation of the EPA GHG reporting rule in 2010 will allow Alaska to benefit from the improved inventory information without incurring additional government costs.

Feasibility Issues

- Capital requirements.
- No regulatory mechanisms are suggested beyond pending federal rules. The state could explore tax or other incentives to encourage capital investment in emission reduction opportunities, such as replacement of compressor wet seals.

Status of Group Approval

Approved.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

[1] New EPA Underground Protection Control Proposed rules for new Class VI Underground Protection Control have been out for comment. The Alaska Oil and Gas Conservation Commission (AOGCC) is participating through the Interstate Oil and Gas Compact Commission and Ground Water Protection Council. The state may apply for primacy when final rules are adopted. See www.epa.gov/ogwdw/uic/wells_sequestration.html for further information.

DRAFT

OG-3. Electrification of North Slope Oil and Gas Operations, With Centralized Power Production and Distribution

Policy Description

This policy recommends that the State of Alaska and the O&G stakeholders commission a detailed study of the economics and technical feasibility of electrification of North Slope O&G operations with centralized power production and distribution. The system could be configured to serve Alaska's major O&G operations throughout the North Slope, and possibly to known expected expansion areas. The focus of the study should be to develop, through various means, incentive programs to promote capital investment in GHG reduction projects.

Currently, 30% of Alaska's reported GHG emissions are generated in the North Slope oil fields, primarily from combustion of natural gas in gas turbines. Centralizing the turbines and taking advantage of improved efficiencies offers the potential to reduce these GHG emissions by a significant portion, which is dependent on the scale of the electrification. The study should also review the possibility of additional overall GHG savings through a combination of policies. This may include a hybrid of OG-3 with OG-4, OG-5, OG-6, and OG-7. A sensitivity analysis should be run using all of the O&G policies with different scenarios with various implementation percentages for the options. There may be a best policy hybrid scheme that could provide a more cost-effective overall thermal efficiency improvement package.

Policy Design

Goals:

- Study the economic and technical feasibility of a centralized power production and distribution system for the O&G production areas on the North Slope of Alaska.
- Determine barriers to the implementation of a centralized electricity production and distribution system.
- Provide recommendations on how to overcome barriers.

Timing: Parties Involved: State of Alaska, BP Exploration Alaska, Inc., ConocoPhillips Alaska, Inc., Chevron, Exxon-Mobil, and the various other smaller O&G producers on the slope and their associated oil drilling support service companies.

Geographic Focus: On the North Slope and in Cook Inlet, where feasible technically and economically on a project-by-project basis. The North Slope and Cook Inlet must be evaluated separately, as the economic considerations are different between the two geographic areas. As most power is utilized on the North Slope, with the largest amount generated at the Prudhoe Bay field, the biggest potential savings in GHG emissions are there.

- The TWG's evaluation of this policy has shown, based on gross economics, that the localized grid for North Slope O&G operations is technically feasible, but is not likely to be economically feasible without significant incentives.

- Cook Inlet was not included in the quantification of this policy, as the largest GHG reduction prize was on the North Slope. If Cook Inlet were to be included in an evaluation, the economic and technical feasibility should be reviewed independently from the North Slope operations. Cook Inlet as a whole is nearing end of usable production life for the known fields. Its current production life cycle, geographic distribution, and physical constraints result in an economic analysis for reducing GHG emissions that is very different from the North Slope analysis. The shorter remaining field life should result in a shorter amortization period, and thus possibly a higher \$/tCO_2e removed cost.

Research Needs: Fully investigate the technical and economic feasibility and any incentives. Review projects individually and as a collective of projects to ensure both short-term and long-term visions are maintained.

Economic Research Areas—Model and recommend the most effective incentives to encourage the capital investment in thermal efficiency improvements for hydrocarbon recovery activities. Take into account any effects on the economy and jobs within the sector and its supporting businesses. Involve the Alaska Department of Revenue (DOR) in this study.

Rough economic viability screening assessments were run without a cost of carbon or potential tax incentives factored in. Additional research into the effect of the value of carbon for both near and long terms may adjust the project value based on the avoided GHG emissions and the value associated with carbon under some future program. Cases were run based on three potential wellhead values of natural gas: \$2, \$4, and \$6/Mscf. The future value of natural gas over the required performance period for the study is very difficult to predict; hence, additional research may be needed.

Technical Research Areas—Engage with any federal, state, or private entities doing research on efficiency upgrades.

Implementation Mechanisms

The study should focus on the financial feasibility of this option, and on ways of encouraging O&G stakeholders to invest the large capital required to implement this policy. There are no insurmountable technical feasibility issues with the implementation of this option. Some regulatory hurdles exists that should be addressed immediately by both the state and the stakeholders. The critical path is for the state to design appropriate incentives to facilitate a significant level of capital investments, and for operators to begin design of facilities needed to maximize the GHG reductions within an acceptable economic framework.

Alaska should simultaneously review the business climate in the state, and ensure that the climate encourages capital investment by the OG stakeholders in a centralized electrical power generation plant and distribution system on the North Slope.

One known barrier to implementation is staffing levels and training of the staff at DEC to provide the required permits in a timely manner. Alaska should ensure that it has a trained and experienced workforce to implement the large permitting and regulatory changes for the North Slope operations within its agencies to help facilitate the implementation of the GHG reduction options.

Specific issues are:

- Legislative and regulatory changes (both federal and state) are needed for existing air quality regulations so that GHG reduction projects can be implemented simply and efficiently without regulatory conflicts. Issues surrounding existing New Source Review (NSR) requirements and GHG reduction projects.
- The state's GHG liaison in Washington, D.C., should work directly with appropriate congressional staffers to shape federal legislation and regulations. Dialogue and input from stakeholders in Alaska need to be routine and are an essential part of the process.
- Work to streamline and coordinate between federal and state regulations.
- Avoid developing regulations that duplicate or potentially conflict with existing or expected federal regulations.
- Conduct a thorough analysis of utility statutes and regulations for unintended consequences that restrict GHG reduction projects. Concerns surround becoming subject to utility requirements.
- Consider changing tax credit legislation and regulations to provide incentives for GHG reduction improvement projects and facilitate project economics.
- Train and retain qualified regulatory staff (DEC, Alaska Department of Natural Resources [DNR], Regulatory Commission of Alaska [RCA], Alaska Oil and Gas Conservation Commission [AOGCC], others) to improve timing and efficiency.
- Streamline the permitting of new/revised facilities designed to reduce GHGs.
- Examine royalties and the lease-term impacts of operating a centralized power grid across lease boundaries (royalties are payable on fuel gas used to generate power that crosses a lease boundary).

Related Policies/Programs in Place

Currently, no policies or programs appear to have a direct impact on this policy.

Types(s) of GHG Reductions

Primarily CO_2 from significant reduction in the amount of fuel gas burned.

Estimated GHG Reductions and Net Costs or Cost Savings

There is a very large potential cost of this policy, with a very rough estimate in the hundreds of millions of dollars to billions of dollars, depending on the scope and complexity. Maximum GHG savings would be gained through implementing this option in conjunction with OG-2: Reductions in Fugitive Methane Emissions, OG-5: Renewable Energy Sources in Oil and Gas Operations, OG-6: Carbon Capture From North Slope High-CO_2 Fuel Gas and Geologic Sequestration With Enhanced Oil Recovery, and OG-7: Carbon Capture [From Exhaust Gas at a Centralized Facility] and Geologic Sequestration With Enhanced Oil Recovery. These policies together have the greatest potential to cut GHG output from North Slope hydrocarbon recovery activities.

Approximately 11.9 $MMtCO_2e$ of GHGs are produced each year in the OG production, transport, and refining sector on the North Slope.[2] Depending on the scope and costs of the project, various amounts could be mitigated. Assuming that massive investment could be generated to fully fund centralization and electrification and improve the overall thermal efficiency of O&G operations for the entire North Slope, approximately half of the current emissions could be mitigated.

This policy should be evaluated in concert with policies OG-1, OG-2, OG-4, OG-5, OG-6, OG-7, and OG-8. The potential overall GHG savings and efficiencies could be maximized using a hybrid approach, as the costs of full implementation of the policies are prohibitive both individually and collectively. These prohibitive costs were developed in a gross-level, rough order-of-magnitude review. The order of magnitude of these estimates should be appropriate and reflective of the costs associated with these policies.

Modeled Costs and GHG Savings:

The estimated GHG aggregate savings through 2025 is 27 $MMtCO_2e$, assuming a phased approach. The estimated annual GHG reductions are based on the number of phases implemented:

- 1 phase - 1.48 $MMtCO_2e$/year.
- 2 phases - 2.96 $MMtCO_2e$/year.
- 3 phases - 4.44 $MMtCO_2e$/year (maximum available phases through 2025).
- 4 phases - 5.91 $MMtCO_2e$/year (full implementation). Implementing all four phases could reduce North Slope GHG emissions by approximately 50% from the baseline established in 2002.

The costs associated with this project are as follows:

- Total estimated capital investment (net present value [NPV]): $7.79 billion.
- Estimated cost per tCO_2e reduced: $293.

Data Sources: BP Exploration Alaska, ConocoPhillips Alaska, Inc., Union Oil Company of California/Chevron, ICF International, EPA, and DEC.

Quantification Methods: Policy options were modeled on generic, publicly available industry data from North Slope oil and gas operations. Thus, results must only be used to help direct more precise modeling, which would include, for example, taxes, royalties, individual oil and gas facility data, and specific engineering studies. Used a ground-up, first principles approach. Current emissions estimated using DEC Draft Inventory based on 2002 fuel burned. Bottom-up costs were estimated for each defined step from field experiences and literature, allowing some comparison and confirmation to similar independent studies—e.g., IPCC, etc. The project is phased in four equal portions, with one phase added every five years. The overall project life is estimated through 2035, with the cumulative project emission reductions taken through 2025 (reduction date for all sectors set by the MAG). The 2035 ”life of project" date allows the large

[2] Based on reported fuel burn data in DEC’s systems, as compiled by the State of Alaska for 2002.

capital investments to be amortized over a longer, more realistic period, so as not to artificially skew the dollar-per-ton cost of the project. Quantification facilitated by ICF International.

Key Assumptions:

- All quantification assumes static activity based on 2008 production data.
- The cost of gas until the major gas sales pipeline is built is $0/Mscf.
- The long-term value of improved hydrocarbon reserves due to burning less fuel gas was not included.
- Costs related to lost production during project construction were not included.
- The wellhead cost of fuel gas after the major sales gas pipeline is built (2019) is $6/Mscf (with sensitivities at $4 and $2/Mscf).
- The cost of carbon is $0/t.
- The project's capital costs are amortized to 2035, due to the large capital expenditures (2025 did not paint an accurate picture).
- A 5% discount rate was modeled. The cost-effectiveness estimates reported here are consistent with the methodology adopted by the MAG. The estimates can be interpreted as a rough indication of the ”social” cost per ton of emissions reduced, and so can be used to rank and compare different abatement options within and across the sector TWGs for policy purposes. However, an estimate of the carbon price at which abatement would first become profitable could be higher than the cost-effectiveness modeled here. The cost-effectiveness estimates are calculated using a lower discount rate than is typically used by industry in determining the profitability of investments, and do not discount emission reductions. Consequently, the modeling may not accurately reflect the industry break-even price. Other factors, such as capital depreciation, would also alter the calculation. See EPA's methodology for calculating break-even prices, available at http://www.epa.gov/methane/pdfs/methodologych4.pdf.

Key Uncertainties

- Future values of carbon were assumed as zero for the TWG's review.
- Value of North Slope natural gas—The TWG ran the studies with $2, $4, and $6/Mscf, to understand the sensitivities associated with the cost of gas.
- The size and scope of the electrification project (facility costs, both for the new facility and for the retrofit).

These uncertainties should be reviewed as part of an encompassing study.

Additional Benefits and Costs

This policy has a direct financial benefit for the state through improved O&G reserves, as well as a GHG emission reduction benefit. The major efficiencies gained with a centralized power grid at major OG operations (especially on the North Slope) would result both in less fuel burned and thus ultimately more gas available for sale, and in lower volumes of GHG, NO_X, sulfur dioxide (SO_2), and particulate matter (PM) emissions. Other costs and benefits include:

- Additional short-term jobs to implement projects.
- Costs of disposing of waste—e.g., abandonment of scrap.
- Land-use cost increase.
- Possible benefits to nearby communities and to expanding OG exploration through access to the electric grid.

Feasibility Issues

- The policy may have significant technical merit, but could fail due to current lease restrictions and complex regulatory hurdles. To help overcome some of these hurdles, Alaska should review how to improve the traditionally slow project permitting, lack of permit streamlining, and complex permitting or authorizations for land use. Extensive cross-agency and regulatory interactions are needed between the companies and the multitude of regulatory agencies with responsibility for coordination of the activities required (EPA, DEC, Alaska Minerals Management Service [MMS], DNR, DOR, U.S. Army Corps of Engineers Alaska District [COE], AOGCC, Alaska North Slope Borough [NSB], RCA, etc.). These agencies should form a commission to help simplify the implementation of GHG projects.
- Currently, the projects are both individually and collectively challenged from an economics standpoint. Therefore, substantial financial incentives need to be explored, including emission credits, tax credits, bonds, technology investment, favorable lease terms, and royalty reduction. The Alaska DOR should be involved in this study.
- The logistics of transporting equipment may necessitate additional significant haul road maintenance and even a possible upgrade.
- A review of the fiscal terms and lease agreements is needed to determine if there are any clauses in the current agreements that create a disincentive for energy efficiency improvements. For example, on the North Slope (unit-by-unit) lease terms may create disincentives for (gas) fuel use efficiency.

Status of Group Approval

Approved.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

OG-4. Improved Efficiency Upgrades for Oil and Gas Fuel-Burning Equipment

Policy Description

This policy recommends that Alaska and the O&G stakeholders commission a detailed study of the economics and technical feasibility of replacing older-technology equipment with newer high-efficiency equipment to improve overall thermal efficiency, thus reducing GHG emissions per unit of generated power. The focus of the study should be to develop, through various means, incentive programs to promote capital investment in GHG reduction projects.

Currently, 30% of Alaska's reported GHG emissions are generated in the North Slope oil fields, primarily from combustion of natural gas in gas turbines. Centralizing the turbines and taking advantage of improved efficiencies offer the potential to reduce these GHG emissions by a significant portion, which is dependent on the scale of the equipment replacement. Looking at this as a stand-alone option, we grossly estimate that replacing older-technology equipment with newer high-efficiency equipment will result in a 17.5% reduction in GHG emissions slope-wide.

The study should also review the possibility of additional overall GHG savings through a combination of policies. This may include a hybrid of OG-4 with OG-3, OG-5, OG-6, and OG-7. A sensitivity analysis should be run using all of the O&G policies with different scenarios that have various implementation percentages for the options. There may be a best policy hybrid scheme that could provide a more cost-effective overall thermal efficiency improvement package.

Policy Design

Goals:

- Study the economic and technical feasibility of replacing the older equipment in service on the North Slope with newer, more efficient equipment. The primary focus of this option is in the O&G production areas on the North Slope of Alaska.
- Determine barriers to the implementation of newer, more efficient equipment.
- Provide recommendations on how to overcome barriers.

Timing: Early studies will facilitate the earliest possible implementation.

Parties Involved: The key parties involved with this project are the State of Alaska, BP Exploration Alaska, Inc., ConocoPhillips Alaska, Inc., Chevron, Exxon-Mobil, and the various other smaller O&G producers on the slope and their associated oil drilling support service companies.

Other:

Geographic Focus: Facilities on the North Slope have the highest potential savings, followed by facilities in the Cook Inlet area. But efficiencies can be gained anywhere if technically feasible, and should be addressed on a project-by-project basis. Projects will be prioritized, and then more promising options will be evaluated separately, as the economics depend on multiple factors, including location, type and age of the machinery to be analyzed, etc.

Quantification was exclusively run on North Slope facilities. Cook Inlet was not directly part of this study, as the limited resources were focused on the North Slope and the largest opportunity was on the North Slope. Cook Inlet onshore facilities could be included in a future evaluation, and economics and technical feasibility would need to be reviewed independently from the North Slope operations. It must be noted that the Cook Inlet as a whole is nearing the end of its usable production life for the known fields. Its current production life cycle, geographic distribution, and physical constraints result in an analysis for reducing GHG emissions that is very different from the North Slope analysis. The shorter remaining field life that results in a shorter amortization period could result in a higher $/t$CO_2$e removed cost.

Research Needs: Fully investigate the technical and economic feasibility and any incentives. Review projects reviewed individually and as a collective of projects to ensure both short-term and long-term visions are maintained.

Economic Research Areas—Model and recommend the most effective incentives to encourage the capital investment in thermal efficiency improvements for hydrocarbon recovery activities. Take into account any effects on the economy and jobs within the sector and its supporting businesses. Involve the Alaska DOR in this study.

All rough economic viability screening assessments were run without a cost of carbon or potential tax incentives factored in. Additional research into the effect of the value of carbon for both near and long terms may adjust the project value based on the avoided GHG emissions and the value associated with carbon under some future program. The cases were run based on three potential values of natural gas: $2, $4, and $6/Mscf. The future value of natural gas over the required performance period for the study is very difficult to predict; hence, additional research may be needed.

Technical Research Areas

- Engage with federal, state, or private entities doing research on efficiency upgrades.
- Study alternative low-CO_2-producing fuels that have up-front CO_2 capture, such as hydrogen produced from field gas methane.
- Review suggestions to current technologies for simple adjustments that could improve thermal efficiency, such as firing temperature changes or thermal efficiency improvement packages from the manufacturers.[3]

Implementation Mechanisms

The study should focus on the financial feasibility of this policy, and focus on ways of encouraging the O&G stakeholders to invest the large capital required to implement this option. There appears to be no insurmountable technical feasibility issues with the implementation of this option, however some regulatory hurdles should be addressed immediately by both the state and the stakeholders. The critical path is for the state to design appropriate incentives to

[3] Could have a negative impact on NO_x production, forcing NSR.

facilitate a significant level of capital investments, and operators to begin design of facilities needed to maximize the GHG reductions within an acceptable economic framework. Significant factors in the economics of this option are the expected future price of natural gas, the level of carbon taxes, and the factors associated with implementing projects on the North Slope. These areas should be reviewed as part of an encompassing study.

Alaska should simultaneously review the business climate in the state and ensure that it encourages capital investment by the O&G stakeholders in newer, more efficient equipment on the North Slope. One known barrier to implementation is staffing levels and training of the staff at DEC to provide the required permits for the task in a timely manner. Alaska should ensure that it has a trained and experienced workforce to implement the large permitting and regulatory changes for the North Slope operations within its agencies, to help facilitate the implementation of the GHG reduction options.

Specific issues are:

- Legislative and regulatory changes (both federal and state) are needed for existing air quality regulations so that GHG reduction projects can be implemented simply and efficiently without regulatory conflicts. Issues surrounding existing NSR requirements and GHG reduction projects.
- The state's GHG liaison in Washington, D.C., should work directly with congressional staffers to shape federal legislation and regulations. Dialogue and input from stakeholders in Alaska need to be routine and are an essential part of the process.
- Work to streamline and coordinate between federal and state regulations.
- Avoid developing regulations that duplicate or potentially conflict with existing or expected federal regulations.
- Conduct a thorough analysis of statutes and regulations for unintended consequences that restrict GHG reduction projects.
- Consider changing tax credit legislation and regulations to provide incentives for GHG reduction improvement projects and facilitate project economics.
- Train and retain qualified regulatory staff (DEC, DNR, RCA, AOGCC, others) to improve timing and efficiency.
- Streamline permitting of new/revised facilities designed to reduce GHGs.

Related Policies/Programs in Place

Currently, no policies or programs appear to have a direct impact on this policy.

Types(s) of GHG Reductions

Primarily CO_2 from significant reduction in the amount of fuel gas burned.

Estimated GHG Reductions and Net Costs or Cost Savings

There potential cost of implementation is very roughly estimated to be in the hundreds of millions of dollars to billions of dollars, depending on the scope and complexity. Maximum

GHG savings would be gained through implementing this policy in conjunction with OG-1: Best Conservation Practices, OG-2: Reductions in Fugitive Methane Emissions, OG-5: Renewable Energy Sources in Oil and Gas Operations, OG-6: Carbon Capture From North Slope High-CO_2 Fuel Gas and Geologic Sequestration With Enhanced Oil Recovery, and OG-7: Carbon Capture From Exhaust Gas at a Centralized Facility and Geologic Sequestration With Enhanced Oil Recovery. These policies together have the greatest potential to cut GHG output from North Slope hydrocarbon recovery activities.

Approximately 11.9 MMtCO_2e of GHGs are produced each year in the O&G production, transport, and refining sector on the North Slope.[4] Depending on the scope and costs of the project, various amounts up to 2 MMtCO_2e could be mitigated through improvements in energy efficiencies. This policy should be evaluated in concert with the policies listed in the preceding paragraph, as the potential overall GHG savings and efficiencies will be maximized using a hybrid approach. These costs were developed in a gross-level, rough order-of-magnitude review. The order of magnitude of these estimates should be appropriate and reflective of the costs associated with these policies.

Modeled Costs and GHG Savings:

The estimated GHG aggregate savings through 2025 is 20 MMtCO_2e, assuming a phased approach. The estimated annual GHG reductions are based on the implementation:

- 2010—0.00 MMtCO_2e/year (savings do not start until after completion of year 5).
- 2015—0.52 MMtCO_2e/year.
- 2020 and beyond—2.069 MMtCO_2e/year (fully implemented and fully realized annual savings). If fully implemented, it would result in an approximate 17.5% annual reduction in North Slope GHG emissions.

The costs associated with this project are as follows:

- Total estimated capital investment (NPV): $1.60 billion.
- Estimated cost per ton of GHG (CO_2e) reduced: $81.

Data Sources: BP Exploration Alaska, ConocoPhillips Alaska, Inc., Union Oil Company of California/Chevron, ICF, EPA, and DEC.

Quantification Methods: Policy options were modeled on generic, publicly available industry data from North Slope oil and gas operations. Thus, results must only be used to help direct more precise modeling, which would include, for example, taxes, royalties, individual oil and gas facility data, and specific engineering studies. Used a ground-up, first principles approach. Current emissions estimated using DEC Draft Inventory based on 2002 fuel burned. Bottom-up costs were estimated for each defined step from field experiences and literature, allowing some comparison and confirmation to similar independent studies—e.g., IPCC, etc. The project has four phases in five-year increments. The overall project life is estimated through 2035, with the cumulative project emission reductions taken through 2025 (reduction date for all sectors,

[4] Based on reported fuel burn data in DEC's systems, as compiled by the State of Alaska for 2002.

established by MAG). The 2035 life-of-project date allows the large capital investments to be amortized over a longer, more realistic period, so as not to artificially skew the dollar-per-ton cost of the project. Quantification facilitated by ICF International.

Key Assumptions:

- All quantification assumes static activity based on 2008 production data.
- The cost of gas until the major gas sales pipeline is built is $0/Mscf.
- The long-term value of improved hydrocarbon reserves from the saved gas.
- The wellhead cost of fuel gas after the pipeline is built (2019) is $6/Mscf (with sensitivities at $4 and $2/Mscf).
- The cost of carbon is $0/t.
- The project's capital costs are amortized to 2035, due to the large capital expenditures (2025 did not paint an accurate picture).
- A 5% discount rate was modeled. The cost-effectiveness estimates reported here are consistent with the methodology adopted by the MAG. The estimates can be interpreted as a rough indication of the "social" cost per ton of emissions reduced, and so can be used to rank and compare different abatement options within and across the sector TWGs for policy purposes. However, an estimate of the carbon price at which abatement would first become profitable could be higher than the cost-effectiveness modeled here. The cost-effectiveness estimates are calculated using a lower discount rate than is typically used by industry in determining the profitability of investments, and do not discount emission reductions. Consequently, the modeling may not accurately reflect the industry break-even price. Other factors, such as capital depreciation, would also alter the calculation. See EPA's methodology for calculating break-even prices, available at http://www.epa.gov/methane/pdfs/methodologych4.pdf.

Key Uncertainties

- Future values of carbon were assumed as zero.
- Value of North Slope natural gas: Studies were run with $2, $4, and $6/Mscf, to understand the sensitivities associated with the cost of gas.
- The size and scope of the overall project. (Facility costs for this type of retrofit in a brownfield environment are very difficult to quantify due to the site-specific nature of each upgrade.)

Additional Benefits and Costs

- This has a direct financial benefit for the state through improved O&G reserves as well as a GHG emission reduction benefit.
- Overall fuel savings (more hydrocarbons available for sale) and lower NO_X, SO_2, and PM emissions.
- Additional short-term jobs to implement projects.

- Cost to dispose of waste, e.g., abandonment of scrap.

Feasibility Issues

- The policy may have significant technical merit, but could fail due to regulatory hurdles. To help overcome some of these hurdles, Alaska should review how to improve the traditionally slow project permitting, lack of permit streamlining, and complex permitting or authorizations for land use. Extensive cross-agency and regulatory interactions are needed between the companies and the multitude of regulatory agencies with responsibility for coordination of the activities required (EPA, DEC, MMS, DNR, DOR, COE, AOGCC, NSB, RCA, etc.). These agencies should form a commission to help simplify the implementation of GHG projects.
- Currently, the projects are both individually and collectively challenged from an economics standpoint. Therefore, substantial financial incentives need to be explored, including emission credits, tax credits, bonds, technology investment, favorable lease terms, and royalty reduction. The Alaska DOR should be involved in this study.
- The logistics of transporting equipment may necessitate additional significant haul road maintenance and even a possible upgrade.
- A review of the fiscal terms and of lease agreements is needed to determine if there are any clauses in the current agreements that create a disincentive for energy efficiency improvements. For example, on the North Slope (unit-by-unit) lease terms may create disincentives for (gas) fuel use efficiency.

Status of Group Approval

Approved.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

OG-5. Renewable Energy Sources in Oil and Gas Operations

Policy Description

This policy is a recommendation that Alaska and OG stakeholders commission a detailed study of the economics and technical feasibility of developing renewable energy sources to improve overall thermal efficiency, thus reducing GHG emissions per unit of generated power. The focus of the study should be to develop, through various means, incentive programs to promote capital investment in GHG reduction projects.

Currently, 30% of Alaska's reported GHG emissions are generated in the North Slope oil fields, primarily from combustion of natural gas in gas turbines. Looking at this as a stand-alone option, a gross estimate of a 6% reduction in GHG emissions is viable through the implementation of renewable energy sources at hydrocarbon recovery facilities.

The study should also review the possibility of additional overall GHG savings through a combination of policies. This may include a hybrid of policies OG-1 through OG-7. A sensitivity analysis should be run using all of the policies with different scenarios with various implementation percentages for the policies. There may be a best policy hybrid scheme that could provide a more cost-effective overall thermal efficiency improvement package.

Policy Design

Goals:

- Study the economic and technical feasibility of using renewable energy to supplement energy required to run O&G production areas on the North Slope of Alaska.
- Determine how to best encourage investment in capital projects to install renewable energy.
- Identify barriers to the implementation of a centralized electricity production and distribution system (which is a prerequisite to allowing large volumes of supplemental renewable energy into the power grid).
- Provide recommendations on how to overcome these barriers.

Timing: Early studies will facilitate the earliest possible implementation.

Parties Involved: The key parties involved with this project are the State of Alaska, BP Exploration Alaska, Inc., ConocoPhillips Alaska, Inc., and all other O&G producers on the slope and their associated oil drilling support service companies.

Other:

Geographic Focus: On the North Slope and in Cook Inlet, where feasible technically and economically on a project-by-project basis. The North Slope and Cook Inlet must be evaluated separately, as the economic considerations are different between the two geographic areas. As most power is utilized on the North Slope, with the largest amount generated at the Prudhoe Bay field, the biggest potential savings in GHG emissions are there.

- Evaluation of this policy has shown, using gross economics, that the use of renewable energy for North Slope O&G operations is technically feasible, but is not economically feasible without a significant level of currently unknown incentive programs.
- Cook Inlet was not directly part of this study, as the limited resources were focused on the North Slope and the largest GHG reduction opportunity was on the North Slope. Cook Inlet onshore facilities could be included in a future evaluation, and economics and technical feasibility would need to be reviewed independently from the North Slope operations. Cook Inlet as a whole is nearing the end of its usable production life for the known fields. Its current production life cycle, geographic distribution, and physical constraints result in an economic analysis for reducing GHG emissions that is very different from the North Slope analysis. The shorter remaining field life that results in a shorter amortization period could result in a higher \$/tCO_2e removed cost.

Research Needs:

Economic Research Areas—Model and recommend the most effective incentives to encourage the capital investment in thermal efficiency improvements for hydrocarbon recovery activities. Take into account any effects on the economy and jobs within the sector and its supporting businesses. Involve the Alaska DOR in this study**.**

All rough economic viability screening assessments were run without a cost of carbon or potential tax incentives factored in. Additional research into the effect of the value of carbon for both near and long terms may adjust the project value based on the avoided GHG emissions and the value associated with carbon under some future program. The cases were run based on three potential values of natural gas: \$2, \$4, and \$6 /Mscf. The future value of natural gas over the required performance period for the study is very difficult to predict; hence, additional research may be needed.

Technical Research Areas

- Engage with federal, state, or private entities doing research on alternative energy.
- Engage with federal, state, or private entities that may be doing research in renewable energy sources, such as wind, hydro, and geothermal, especially as they are related to conditions found in Alaska.
- Study the location and types of renewable options to enhance the thermal efficiency of hydrocarbon recovery activities.

Implementation Mechanisms

The study should focus on the financial feasibility of this policy, and focus on ways of encouraging the O&G stakeholders to invest the large capital required to implement this policy. There are no insurmountable technical feasibility issues with this policy, but there are some regulatory hurdles that should be addressed immediately by both the state and the stakeholders. The critical path is for (1) the state to design appropriate incentives to facilitate a significant level of capital investments, and (2) operators to begin design of facilities needed to maximize the GHG reductions within an acceptable economic framework. Significant factors in the economics of this policy are future gas and carbon prices and the factors associated with implementing projects on the North Slope. These areas should be reviewed as part of an encompassing study.

Specific issues are:

- Legislative and regulatory changes (both federal and state) are needed for existing air quality regulations, so that GHG reduction projects can be implemented simply and efficiently without regulatory conflicts. Issues surrounding existing NSR requirements and GHG reduction projects.
- The state's GHG liaison in Washington, D.C., should work directly with congressional staffers to shape federal legislation and regulations. Dialogue and input from stakeholders in Alaska need to be routine and are an essential part of the process.
- Work to streamline and coordinate between federal and state regulations.
- Avoid developing regulations that duplicate or potentially conflict with existing or expected federal regulations.
- Conduct a thorough analysis of utility statute and regulations for unintended consequences that restrict GHG reduction projects. Concerns surround becoming subject to utility requirements.
- Consider changing tax credit legislation and regulations to provide incentives for GHG reduction improvement projects and facilitate project economics.
- Train and retain qualified regulatory staff (DEC, ADNR, RCA, AOGCC, others) to improve timing and efficiency.
- Streamline permitting of new/revised facilities designed to reduce GHGs.
- Examine royalties and the lease-term impacts of operating a centralized power grid across lease boundaries (royalties are payable on fuel gas used to generate power that crosses a lease boundary).

Related Policies/Programs in Place

No existing policies or programs appear to have a direct impact on this policy.

Types(s) of GHG Reductions

Primarily (CO_2) from significant reduction in the amount of fuel gas burned.

Estimated GHG Reductions and Net Costs or Cost Savings

Costs of the project are very roughly estimated to be in the hundreds of millions of dollars to billions of dollars, depending on the scope and complexity. Large-scale energy from renewable sources can only be used if there is an electrical grid to feed into, electrification has taken place, and sufficient backup power is available when the wind is not blowing. Hence, all aspects of OG-3: Electrification of North Slope Oil and Gas Operations with Centralized Power Production and Distribution are required prerequisites for this option. Additionally, maximum GHG savings would be gained through implementing this option in conjunction with OG-1: Best Conservation Practices, OG-2: Reductions in Fugitive Methane Emissions, OG-4: Improved Efficiency Upgrades for Oil and Gas Fuel-Burning Equipment, OG-6: Carbon Capture From North Slope High-CO_2 Fuel Gas and Geologic Sequestration With Enhanced Oil Recovery, and OG-7: Carbon Capture From Exhaust Gas at a Centralized Facility and Geologic Sequestration with

Enhanced Oil Recovery. These policies implemented together have the greatest potential to cut GHG output from North Slope hydrocarbon recovery activities.

Approximately 11.9 $MMtCO_2e$ of GHGs are produced each year in the O&G production, transport, and refining sector on the North Slope.[5] Depending on the scope and costs of the project, various amounts could be mitigated by the addition of renewable wind energy. Adding wind power to a centralized gas facility could mitigate 0.75 $MMtCO_2e$.

This policy should be evaluated in concert with policies identified above, as the potential overall GHG savings could end up being greater than the baseline values.[6] The costs of the policies are prohibitive for implementing them both individually and collectively. These costs were developed in a gross-level, rough order-of-magnitude review. The order of magnitude of these estimates should be appropriate and reflective of the costs associated with these options.

Modeled Costs and GHG Savings: The estimated GHG aggregate savings through 2025 is 8 $MMtCO_2e$. The estimated annual GHG reductions are based on North Slope wind data and immediate implementation of wind power at a centralized gas facility, with the annual savings estimated at 0.7 $MMtCO_2e$.

The costs associated with this project are as follows:

- Total estimated capital investment (NPV): $2.60 billion.
- Estimated cost per ton of GHG (CO_2e) reduced: $327.

Data Sources: BP Exploration Alaska, ConocoPhillips Alaska, Inc., Union Oil Company of California/Chevron, ICF, EPA, and DEC.

Quantification Methods: Policy options were modeled on generic, publicly available industry data from North Slope oil and gas operations. Thus, results must only be used to help direct more precise modeling, which would include, for example, taxes, royalties, individual oil and gas facility data, and specific engineering studies. Used a ground-up, first principles approach. Current emissions estimated using DEC Draft Inventory based on 2002 fuel burned. Bottom-up costs were estimated for each defined step from field experiences and literature, allowing some comparison and confirmation to similar independent studies—e.g., IPCC, etc. The project is implemented immediately, with an overall project life estimated through 2035, and cumulative project emission reductions estimated through 2025 (reduction dates established for all sectors by the MAG). The 2035 life of project date allows the large capital investments to be amortized over a longer, more realistic period, so as not to artificially skew the dollar-per-ton cost of the project. Quantification facilitated by ICF International.

Key Assumptions:

- All quantification assumes static activity based on 2008 production data.
- The current Central Power Station in Prudhoe Bay is augmented.
- The wellhead cost of gas until the gas pipeline is built is $0/Mscf.

[5] Based on reported fuel burn data in DEC's systems, as compiled by the State of Alaska for 2002.

[6] Ibid.

- No value was given for the long-term increase in hydrocarbon reserves related to the saved gas.
- The wellhead cost of fuel gas after the pipeline is built (2019) is $6/Mscf (sensitivities at $4 and $2/Mscf).
- The cost of carbon is $0/t.
- The project's capital costs are amortized to 2035, due to the large capital expenditures (2025 did not paint an accurate picture).
- A 5% discount rate was modeled. The cost-effectiveness estimates reported here are consistent with the methodology adopted by the MAG. The estimates can be interpreted as a rough indication of the "social" cost per ton of emissions reduced, and so can be used to rank and compare different abatement options within and across the sector TWGs for policy purposes. However, an estimate of the carbon price at which abatement would first become profitable could be higher than the cost-effectiveness modeled here. The cost-effectiveness estimates are calculated using a lower discount rate than is typically used by industry in determining the profitability of investments, and do not discount emission reductions. Consequently, the modeling may not accurately reflect the industry break-even price. Other factors, such as capital depreciation, would also alter the calculation. See EPA's methodology for calculating break-even prices, available at http://www.epa.gov/methane/pdfs/methodologych4.pdf.

Key Uncertainties

- Future values of carbon were assumed as zero.
- Value of North Slope natural gas—The TWG ran the studies with $2, $4, and $6/Mscf, to understand the sensitivities associated with the cost of gas.
- The size and scope of the renewable energy project.
- The size and scope of the requisite electrification project (OG-3) needed, so that the electrical power generated by renewable sources can be utilized.

Additional Benefits and Costs

- The state would benefit from a centralized power grid at major O&G operations (especially the North Slope), in that the major efficiencies gained mean less fuel burned, and more fuel ultimately available for sale. In addition, the citizens of the state would benefit, as the less fuel burned, the lower the GHG emissions.
- Overall fuel savings (more hydrocarbons available for sale) and lower NO_X, SO_2, and PM emissions.
- Additional short-term jobs to implement projects.
- Land-use cost increases.
- Possible benefits to nearby communities and to expanding O&G exploration through access to the electric grid.

Feasibility Issues

- The policy may have significant technical merit, but could fail due to current lease restrictions and complex regulatory hurdles. To help overcome some of these hurdles, Alaska should review how to improve the traditionally slow project permitting, lack of permit streamlining, and complex permitting or authorizations for land use. Extensive cross-agency and regulatory interactions are needed between the companies and the multitude of regulatory agencies with responsibility for coordination of the activities required (EPA, DEC, MMS, DNR, DOR, COE, AOGCC, NSB, RCA, etc.). These agencies should form a commission to help simplify the implementation of GHG projects.
- Currently, the projects are both individually and collectively challenged from an economics standpoint. Therefore, substantial financial incentives need to be explored, including emission credits, tax credits, bonds, technology investment, favorable lease terms, and royalty reduction. The Alaska DOR should be involved in this study.
- The logistics of transporting equipment may necessitate additional significant haul road maintenance and even a possible upgrade.
- A review of the fiscal terms of lease agreements is needed to determine if there are any clauses in the current agreements that create a disincentive for energy efficiency improvements. For example on the North Slope (unit-by-unit) lease terms may create disincentives for (gas) fuel use efficiency.

Status of Group Approval

Approved.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

OG-6. Carbon Capture (From North Slope High-CO_2 Fuel Gas) and Geologic Sequestration With Enhanced Oil Recovery

Policy Description

This policy relates to the technical feasibility and economics of CO_2 separation from produced gas, transport, and geologic sequestration (carbon capture and storage [CCSR]) from gas used for fuel in and around Prudhoe Bay. The technical goal is to remove and sequester the 10%–12% CO_2 from the natural gas produced at Prudhoe before that gas is burned in power generators, thereby lowering North Slope emissions by approximately 8%, or ~1 $MMtCO_2$/yr. The geologic sequestration should utilize a reservoir where enhanced oil recovery (EOR) can improve the economics.

This policy is very similar to OG-7, but differs in that it calls for removing CO_2 from entrained gas pre-combustion, rather than from post-combustion, exhaust gases. Capturing the emissions post-combustion is a significantly more complicated procedure. With regard to sequestration, this policy is identical to OG-7.

Policy Design

Goals:

- Initiate studies on the technical and economic aspects of implementation. The economic analysis should include design of appropriate financial incentives to responsibly encourage capital investments. The technical analysis should be conducted to choose an appropriate CO_2 capture technology and the best reservoir for CO_2 injection to maximize economics, especially relating to EOR benefits.
- Study the implementation of this policy in conjunction with energy efficiency policies OG-3, OG-4, and OG-5, to both minimize the amount of CO_2 that needs to be processed as well as reduce resource waste.
- Encourage investment through incentives:
    - Financial:
        - Provide federal and state carbon credits.
        - Provide tax incentives for capital investments.
    - Regulatory:
        - Simplify/streamline the regulatory environment.
        - Avoid overlapping state and federal regulations of GHG emissions and underground injections. Recommend coordinating with and participating in the development of federal regulations to ensure the regulations fit Alaska's conditions.
        - Study state permitting/regulatory personnel requirements. Establish policies to pay and retain sufficient qualified employees to cover additional workloads.

Timing: Early studies will facilitate the earliest possible implementation.

This policy could logically be implemented before OG-7, and all the CO_2 captured would likely be able to be utilized in EOR, thereby maximizing the economic benefits. However, since energy is needed to power CCSR (burning gas and creating more CO_2), improving energy efficiency to minimize the volume of gas that needs to be treated is desired. Energy efficiency options (OG-3, OG-4, and OG-5) should be considered in order to minimize waste.

A "pure" sequestration project could not be permitted at this time, as the regulations are currently being developed. The permitting process is in place for EOR applications.

Parties Involved:

- Consultants to conduct the study on technical and economic feasibility.
- North Slope operator technical representatives.
- Operators of neighboring oil fields who might benefit from CO_2 EOR—e.g., Endicott Field.
- State of Alaska (DNR, AOGCC, DEC, DOR, etc.).

Research Needs:

Economic Research

- Model the effects on the economy and jobs with various scenarios. Involve Alaska DOR in this analysis.
- Research the long-term value of carbon, which could have a huge impact on the economics of these projects.
- Research the long-term value of natural gas.

Technical Research

- Engage with and observe the U.S. Department of Energy (DOE) Phase III pilot project testing of various CCSR technologies.
- Conduct a technical feasibility study of the different entrained CO_2 capture technologies.

Incentives: Financial, Permitting, Etc.

- Provide appropriate tax credits for investment in CCSR and EOR. Note that current larger tax credits for CCSR over EOR (\$20/t versus \$10/t) could lead to a financial incentive to inject into an aquifer rather than into a reservoir for EOR, thereby potentially shortening field life.
- Streamline the permitting process, which is critical for project turnaround.
- Consider a joint agency similar to the Joint Pipeline Office (JPO) to facilitate efficiencies in permitting between agencies (only needed in cases of cross-unit applications.) Currently, the AOGCC is the main regulatory agency for permitting for underground injection of CO_2 for EOR. An additional facilitating agency might be beneficial in the case of cross-unit or special requirements mandated by eventual federal regulations for underground injection of CO_2 for sequestration.

Implementation Mechanisms

To minimize the time required for implementation, regulatory and capital investment hurdles should be addressed immediately. A critical path is for the state to design incentives encouraging the major capital investments that will be required; operators to begin the design of facilities needed to strip the CO_2 from the fuel stream, transport it to a reservoir, and inject it for EOR; and finally the state and operators to start working on the complicated regulatory and permitting issues. The final economics will depend on the value for carbon and fuel gas. Financing CCSR projects will be sensitive to that value, and will be dependent on future cap-and-trade or carbon tax legislation.

Broad Recommended Evaluation

- Determine the relative benefits of various pre-combustion capture techniques (such as membrane versus solvent treatment).
- Study CO_2 sequestration and EOR benefits within selected reservoirs. The choice of a final sequestration site should be based on safety, long term-storage capability, and economics. The more robust the economics, the faster this technology can be put into place. Since studies show that many oil fields in and around Prudhoe Bay would benefit from EOR, it should be considered wherever feasible in the planning of CCSR projects on the North Slope.

Specific Recommended Evaluation

Risks and uncertainties in the following categories should be addressed:

- Maturity of and applicability of various capture technologies.
- Costs for capture, transport, and sequestration.
- Potential for CO_2 leakage.
- Potential EOR benefits.

Detailed analysis should cover:

- Applicable capture technologies, pros and cons, recommendation for pilot.
- Pros and cons of surrounding reservoirs for sequestration.
- Availability and costs of new or upgraded facilities, power, space, and water requirements.
- Costs for geological and geophysical studies for site selection and monitoring.
- Costs for drilling wells that are not suitable for storage.
- Costs for down-hole well testing, maintenance, and repairs.
- Value from possible tax or carbon credits.
- Value from added reserves due to EOR.

- Estimates of CO_2 emissions avoided (including additional emissions from capture, transport, and injection operations).
- Risk assessment for short- and long-term storage.
- Impacts on estimated ultimate recovery (EUR) and conservation/production of resources, e.g., impact on EOR recovery of maximizing CO_2 storage).
- Regulatory requirements (e.g., EPA UIC program, other state and federal requirements).
- Monitoring requirements (pre-, during, and post-injection).

Related Policies/Programs

Existing Policies

- EPA regulations for underground injection for EOR.
- Some tax incentives for CCSR and EOR exist in current federal legislation (carbon mitigation incentives included in the Emergency Economic Stabilization Act of 2008).

Policies Under Development or Needed

- EPA regulations regarding CO_2 underground sequestration.[7] The state may seek primacy for this activity upon final EPA rulemaking.
- EPA regulations, if any, and other federal laws regarding air quality, water quality, carbon tax or cap and trade, etc.
- State/local government permitting, as necessary, addressing issues beyond EPA underground injection control (UIC) CO_2 sequestration rules.
  - Ownership issues—surface rights versus mineral rights versus pore space rights.
  - Long-term liability at sequestration sites.
  - Royalties and lease-term impacts of CO_2 sequestration and use for EOR.
  - Land-use regulations and requirements.
- Potential federal cap-and-trade legislation and ultimate EPA air quality regulations.
  - Potential conflict between increased fuel use (decreased hydrocarbon reserves) due to capture and injection, and benefits for reduction of CO_2 through sequestration.

Related Policies/Programs

- This policy is closely related to OG-7, CCSR from exhaust gas post-combustion in and near O&G fields with potential EOR.
- There are many synergies with eventual sales of North Slope gas.

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[7] New EPA Underground Protection Control Proposed rules for new Class VI Underground Protection Control have been out for comment. AOGCC, participating through Interstate Oil and Gas Compact Commission and Ground Water Protection Council. The state may apply for primacy when final rules are adopted. See www.epa.gov/ogwdw/uic/wells_sequestration.html for further information.

Types(s) of GHG Reductions

CO_2 removed from fuel gas used at Prudhoe Bay before combustion, and injected into an underground reservoir for EOR and long-term sequestration.

Estimated GHG Reductions and Net Costs or Cost Savings

Potential emission savings through CO_2 capture from entrained gas used for fuel at Prudhoe Bay to EOR injection at Endicott Field could be on the order of 1 $MMtCO_2$/yr.

A gross economic estimate, modeled using best guesses on capture, transport, and injection costs, as well as benefit from EOR, is $176/t. The estimate for expected yearly reduction in CO_2 emissions is 0.9 $MMtCO_2e$, and the estimate for the total reduced emissions through 2025 is 7.8 $MMtCO_2e$. Due to the size and complexity of this type of project, there is significant uncertainty in this estimate of $/t.

Due to the very large investments required, as well as timing and logistical constraints, large amounts of capital expenditures occur toward the end of the measurement period (2025). To avoid presenting a misleading number, capital and operating costs were amortized to 2035 when calculating $/$tCO_2$ of mitigated emissions. Capital expenditures will be required by facility owners, as significant retrofitting of existing power-generating facilities will be needed. In addition, significant amounts of fuel will be burned to power the capture, compression, and injection process. Currently, that fuel has zero value, but in the advent of gas sales, that gas has value. Additional expenditures will be required for CO_2 transport pipelines and injection wells, as well as for a long-term monitoring program.

Data Sources: IPCC, DEC, AOGCC, O&G TWG members, API, *Oil and Gas Journal*, 2nd Annual Conference on Carbon Sequestration.

Quantification Methods: Policy options were modeled on generic, publicly available industry data from North Slope oil and gas operations. Thus, results must only be used to help direct more precise modeling, which would include, for example, taxes, royalties, individual oil and gas facility data, and specific engineering studies. Used a ground-up, first principles approach. Current emissions estimated using DEC Draft Inventory based on 2002 fuel burned. Bottom-up costs were estimated for each defined step from field experiences and literature, allowing some comparison and confirmation to similar independent studies, e.g., IPCC, etc. Quantification facilitated by ICF International.

Key Assumptions:

- All quantification assumes static activity based on 2008 production data.
- The cost of natural gas until a gas pipeline is built is $0/Mscf.
- The wellhead cost of natural gas after a pipeline is built (assumed 2019) is $6/Mscf, and sensitivities were run at $2, $4, and $6/Mscf.
- The cost of carbon is $0/t.
- Capital and operating costs were amortized to 2035 to get an accurate cost/metric ton.

- Endicott Field is used for EOR cost estimates. (It has appropriate metallurgy in the production facilities.)
- Sufficient EOR opportunities will be available for all captured CO_2. (This has yet to be demonstrated, in addition to the CO_2 expected from major gas sales.)
- A 5% discount rate was modeled. The cost-effectiveness estimates reported here are consistent with the methodology adopted by the MAG. The estimates can be interpreted as a rough indication of the "social" cost per ton of emissions reduced, and so can be used to rank and compare different abatement options within and across the sector TWGs for policy purposes. However, an estimate of the carbon price at which abatement would first become profitable could be higher than the cost-effectiveness modeled here. The cost-effectiveness estimates are calculated using a lower discount rate than is typically used by industry in determining the profitability of investments, and do not discount emission reductions. Consequently, the modeling may not accurately reflect the industry break-even price. Other factors, such as capital depreciation, would also alter the calculation. See EPA's methodology for calculating break-even prices, available at http://www.epa.gov/methane/pdfs/methodologych4.pdf.

Key Uncertainties

Key hurdles are investment, capital cost, and regulatory environment.

Economic

- Value of natural gas, current and future.
- Future values of carbon.
- Hydrocarbon reserves impact, value and amount of EOR reserves.
- Facilities upgrade costs.

Logistical

- Regulatory environment (for permitting, for CCSR projects still being developed, for long-term monitoring requirements, conflicting state and federal regulations, etc.). A significant commitment from regulators will be needed to overcome existing hurdles in the permitting, royalty, and regulatory environments.
- Availability of resources—building materials, space in existing facilities, water, etc.
- Public acceptance of long-term CO_2 storage.

Long Term (after project can no longer be classified as EOR)

- Leakage—Is leakage authorized? If so, what amount/percentage?)
- Long-term CCSR—How long is long term?
- Liability—Who is liable, and for how long?
- Logistical, legal, and royalty issues of cross-unit operations (if the reservoir for EOR is not in the same unit as Prudhoe).

- Time frame—How long to permit? How long to build?

Additional Benefits and Costs

In 2005, about 1.25 $MMtCO_2$ emissions on the North Slope were due to naturally occurring CO_2 entrained within the gas. In addition to the immediate benefit of capturing CO_2 prior to combustion, studying and potentially implementing a pilot for the capture and sequestration of CO_2 from fuel gas can provide long-term benefits for eventual gas sales. Sale gas specifications will require removal of most of the CO_2 from much larger gas volumes than are currently handled. (At projected gas sales production rates of 2–4 billion standard cubic feet per day, 5–10 $MMtCO_2$/yr will ultimately need to be captured and sequestered.)

Longer term, this technology will need to be implemented for eventual gas sales, and at that point the economics could improve for treating fuel gas.

In addition to the benefit of reduced CO_2 emissions, sequestering the CO_2 in a reservoir where it can be used to enhance the oil recovered has great potential value.

Benefits

- Significant economic advantages can be obtained if the initial CO_2 sequestration is partnered with EOR. Where EOR is effective, and reports indicate that many fields on the North Slope would benefit,[8] injection of CO_2 "washes out" residual oil left after initial production. While much of this CO_2 is cycled back to the surface with residual oil, a significant percentage remains trapped in the reservoir, even while active cycling is taking place. The rest of the CO_2 cycles up mixed with residual oil, is separated at the surface, and is re-injected into the reservoir. This cycling continues until EOR is no longer productive, at which point all the CO_2 in the reservoir remains sequestered. At that time, CO_2 could theoretically continue to be injected until injection pressure or some other operational limit is reached.
- Longer term, this technology will need to be implemented for eventual gas sales, if only due to pipeline specifications requiring no more than 1.5% CO_2. Implementing this technology now would act as a large-scale pilot for eventual gas sales.

Costs

- Burning leaner gas could release more NO_x by volume, triggering regulations requiring additional capital-intensive control technologies.
- Capital costs for capture, transport, and injection of CO_2.
- Parasitic energy—i.e., extra power used to capture the CO_2. Additional fuel gas is burned to provide power needed for compression, dehydration, transport, and injection.
- Possible additional water requirements.
- Increased operating costs.

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[8] Advanced Resources International. April 2005. *Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Alaska.* Prepared for the U.S. Department of Energy, Office of Fossil Energy–Office of Oil and Natural Gas. Available at: http://www.adv-res.com/unconventional-gas-literature.asp.

- Impact on global competitive standing if the U.S. cost structure is significantly higher than in countries without emission limits.
- Increased cost of energy affects the overall cost of living for all.
- Higher cost structure may shorten ultimate field life and EUR of hydrocarbons.

Feasibility Issues

Capital Requirements

- State and federal (especially EPA) regulatory environment for CCSR projects—not yet established. Legal requirements and liability issues are unknown for long-term CO_2 storage, which have a major impact on cost and timing.
- Pre-combustion CO_2 removal is commonly used in industry, but has never been implemented on the North Slope.
- Other—See Key Uncertainties, above.

Status of Group Approval

Approved.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

OG-7. Carbon Capture (From Exhaust Gas at a Centralized Facility) and Geologic Sequestration With Enhanced Oil Recovery

Policy Description

This policy relates to the technical feasibility and economics of post-combustion CO_2 capture, transport, and geologic sequestration in or near existing Alaska O&G fields, including the upside of initial EOR.

Currently, 30% of the reported CO_2 emissions from Alaska are generated in the North Slope oil fields, primarily from combustion for power generation.[9] Fortuitously, the co-located or nearby O&G reservoirs provide large volumes of potential storage space. In addition, many of the oil reservoirs are likely candidates for CO_2 EOR. Quantification for this policy is focused on the central gas facility (CGF) at Prudhoe Bay, as preliminary studies have shown that CCSR would have the highest possible efficiencies at this facility, due to the concentration and sizes of the turbines. CGF accounts for ~16% of all North Slope emissions.

This policy is very similar to OG-6, but differs in that it calls for removing CO_2 from exhaust or flue gases post-combustion, as opposed to removing it from entrained gas pre-combustion. Capturing the CO_2 post-combustion is a more complicated and expensive process, as each individual piece of machinery needs to be adapted for the capture process. Additionally, the transport is more complicated and expensive due to the many point sources of capture. With regard to sequestration, this policy is identical to OG-6.

Most concepts and issues related to carbon capture and geologic sequestration in O&G fields discussed in this policy would apply to many facilities in Cook Inlet as well, but the cost structures and logistics there are very different and would require an independent analysis.

Policy Design

Goals:

- Initiate studies on the technical and economic aspects of implementation. The economic analysis should include design of appropriate financial incentives to responsibly encourage capital investments. The technical analysis should include the size and type of facilities modifications, choice of appropriate combustion CO_2 capture technology, and choice of best reservoir for CO_2 injection to maximize economics, especially relating to EOR benefits.
- Study the implementation of this option after, or in some cases in conjunction with, energy efficiency options OG-3, OG-4, and OG-5 to minimize the amount of CO_2 that needs to be processed.
- Encourage investment through incentives:

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[9] Alaska Department of Environmental Conservation. January 2008. "DRAFT—Summary Report of Improvements to the Alaska Greenhouse Gas Emission Inventory." (Includes Final Alaska GHG Inventory and Reference Case Projection.) Available at: http://www.climatechange.alaska.gov/docs/ghg_ei_rpt.pdf.

- Financial:
  - Provide federal and state carbon credits.
  - Provide tax incentives for capital investment requirements.
- Regulatory:
  - Simplify/streamline the regulatory environment.
  - Avoid overlapping state and federal regulations of GHG emissions and underground injections. Recommend coordinating with and participating in development of federal regulations to ensure the regulations both fit Alaska's conditions and allow for early implementation.
  - Study the state permitting and regulatory personnel requirements. Establish policies to pay and retain sufficient qualified employees to cover additional workloads.

Timing:

- Early studies will facilitate the earliest possible implementation.
- It is expected that EOR will be able to fully utilize all the CO_2 that could be captured by the application of this policy at the Prudhoe Bay CGF, even if OG-6 is operating concurrently. However, since energy is needed to power CCSR (burning gas and creating more CO_2), improving energy efficiency to minimize the gas that needs to be treated is desired. Energy efficiency policies (OG-3, OG-4, and OG-5) should be considered in order to minimize waste.
- A "pure" sequestration project could not be permitted at this time, as regulations are currently being developed. The permitting process is in place for EOR applications.

Parties Involved:

- Consultants for conducting the study on technical and economic feasibility.
- North Slope operator technical representatives.
- Operators of neighboring oil fields who might benefit from CO_2 EOR—e.g., Endicott Field.
- State of Alaska (DNR, AOGCC, DEC, DOR, etc.).

Other:

Geographic Focus

- While this policy's focus is on Prudhoe Bay, lessons learned here on capture may be applied to Cook Inlet's major emission sources (Beluga Power Plant, the liquefied natural gas plant, and the Tesoro refinery), where future fully depleted onshore O&G fields may be a sequestration opportunity. Cook Inlet was not part of the quantification of this option. If it were to be included in an evaluation, the economic and technical feasibility should be reviewed independently from the North Slope operations.
- The Cook Inlet O&G field production life cycle, geographic distribution, and physical constraints result in potentially higher costs for reducing GHG emissions than on the North Slope.

- There is potential for future coal-to-gas/liquids production in Cook Inlet, which may present additional sources of GHG emissions that in turn will be targets for sequestration.

Research Needs:

Economic Research

- Answer the question of appropriate incentives.
- Model the effects on the economy and jobs with various scenarios.
- Involve Alaska DOR in this analysis.
- Research the long-term value of carbon, which can have a huge impact on the economics of these projects.
- Research the long-term value of natural gas.

Technical Research

- Engage with and observe the DOE Phase III pilot project testing of various capture and sequestration technologies.
- Conduct a technical feasibility study of the different post-combustion CO_2 capture technologies.
- Update the 2003 study of the Prudhoe Bay CGF, and determine the costs and requirements to retrofit existing facilities to add CO_2 capture technology, pipelines, compressors, and dehydrators, as well as wells needed to inject/cycle CO_2 in Endicott Field.

Incentives: Financial, Permitting, Etc.

- Provide appropriate tax credits for investment in CCSR and EOR. Note that current larger tax credits for CCSR over EOR ($20/t versus $10/t) could lead to a financial incentive to inject into an aquifer rather than into a reservoir for EOR, thereby potentially shortening field life.
- Streamline permitting critical for project turnaround.
- Consider creating a joint agency similar to the JPO to facilitate efficiencies in permitting between agencies (only needed in case of cross-unit applications.) Currently, the AOGCC is the main regulatory agency for permitting for underground injection of CO_2 for EOR. An additional facilitating agency might be beneficial in the case of cross-unit or special requirements mandated by eventual federal regulations for underground injection of CO_2 for sequestration.

Implementation Mechanisms

To minimize time required for implementation, regulatory and capital investment hurdles should be addressed immediately. A critical path is for the state to design incentives encouraging the major capital investments that will be required; operators to begin the design of facilities needed to strip the CO_2 from the individual fuel exhaust streams, transport it to appropriate reservoirs, and inject it for EOR; and the state and operators to immediately start working on the complicated regulatory/permitting issues. Studies should include space, power, and water requirements for each facility. Final economics will depend on the value for carbon. Financing CCSR projects will be sensitive to that value, and will be dependent on future cap-and-trade or carbon tax legislation.

Related Policies/Programs

Existing Policies

- EPA regulations for underground injection for EOR.
- Some tax incentives for CCSR exist in current federal legislation (carbon mitigation incentives included in the Emergency Economic Stabilization Act of 2008).

Policies Under Development or Needed

- EPA regulations regarding CO_2 underground sequestration.[10] The state may seek primacy for this activity upon final EPA rulemaking.
- EPA regulations, if any, and other federal laws regarding air quality, water quality, carbon tax or cap and trade, etc.
- State/local government permitting, as necessary, addressing issues beyond EPA UIC CO_2 sequestration rules.
    - Ownership issues—surface rights versus mineral rights versus pore space rights.
    - Long-term liability at sequestration sites.
    - Royalties and lease-term impacts of CO_2 sequestration and use for EOR.
    - Land-use regulations and requirements.
- Potential federal cap-and-trade legislation and ultimate EPA air quality regulations.
    - Potential conflict between increased fuel use (decreased hydrocarbon reserves) due to capture and injection, and benefits for reduction of CO_2 through sequestration.

Related Options

This policy is closely related to OG-6, CCSR from entrained gas pre-combustion, in and near O&G fields with potential EOR.

Types(s) of GHG Reductions

CO_2 removed from fuel gas post-combustion exhaust streams at Prudhoe Bay, and injected into an underground reservoir for EOR and long-term sequestration.

Estimated GHG Reductions and Net Costs or Cost Savings

- Potential emission savings through CO_2 capture from exhaust gases at the Prudhoe Bay CGF facility and EOR injection at Endicott Field could be on the order of 2 $MMtCO_2$/yr.

[10] New EPA Underground Protection Control Proposed rules for new Class VI Underground Protection Control have been out for comment. AOGCC is participating through the Interstate Oil and Gas Compact Commission and the Ground Water Protection Council. The state may apply for primacy when final rules are adopted. See www.epa.gov/ogwdw/uic/wells_sequestration.html for further information.

- A gross economics estimate, modeled using best guesses on capture, transport, and injection costs, as well as benefit from EOR, is \$157/t. The estimate for expected yearly reduction in CO_2 emissions is 1.8 MMtCO_2e, and the estimate for total reduced emissions through 2025 is 19.7 MMtCO_2e. Due to the size and complexity of this type of project, there is significant uncertainty in the \$/t.
- Due to the very large investments required, as well as timing and logistical constraints, large amounts of capital expenditures occur toward the end of the measurement period (2025.) To avoid presenting a misleading number, capital and operating costs were amortized to 2035 when calculating \$/tCO_2 of mitigated emissions. Large capital expenditures will be required by facility owners, as significant retrofitting of existing power-generating facilities will be needed. In addition, significant amounts of fuel will be burned to power the capture, compression, and injection process. Currently, that fuel has zero value, but in the advent of gas sales, that gas has value. Additional expenditures will be required for CO_2 transport pipelines and injection wells, as well as for a long-term monitoring program.
- Significant commitment from regulators will be needed to overcome existing hurdles in the permitting, royalty, and regulatory environments.

Data Sources: IPCC, DEC, AOGCC, O&G TWG members, API, *Oil and Gas Journal*, 2nd Annual Conference on Carbon Sequestration, DOE.

Quantification Methods: Policy options were modeled on generic, publicly available industry data from North Slope oil and gas operations. Thus, results must only be used to help direct more precise modeling, which would include, for example, taxes, royalties, individual oil and gas facility data, and specific engineering studies. Used a ground-up, first principles approach. Quantification facilitated by ICF International. Current emissions estimated using DEC Draft Inventory based on 2002 fuel burned. Bottom-up costs were estimated for each defined step from field experiences and literature, allowing some comparison and confirmation to similar independent studies, e.g., IPCC, etc.

Key Assumptions:

- All quantification assumes static activity based on 2008 production data.
- The cost of natural gas until a gas pipeline is built is \$0/Mscf.
- The wellhead cost of natural gas after a pipeline is built (assumed 2019) is \$6/Mscf. (Sensitivities were run at \$2, \$4, and \$6/Mscf.)
- The cost of carbon is \$0/t.
- Capital and operating costs were amortized to 2035 to get an accurate cost per metric ton.
- Endicott Field was used for EOR cost estimates. (It already has appropriate metallurgy.)
- Sufficient EOR opportunities will be available for all captured CO_2. (This has yet to be demonstrated, in addition to the CO_2 expected from major gas sales.)
- A 5% discount rate was modeled. The cost-effectiveness estimates reported here are consistent with the methodology adopted by the MAG. The estimates can be interpreted as a rough indication of the "social" cost per ton of emissions reduced, and so can be used to

rank and compare different abatement options within and across the sector TWGs for policy purposes. However, an estimate of the carbon price at which abatement would first become profitable could be higher than the cost-effectiveness modeled here. The cost-effectiveness estimates are calculated using a lower discount rate than is typically used by industry in determining the profitability of investments, and do not discount emission reductions. Consequently, the modeling may not accurately reflect the industry break-even price. Other factors, such as capital depreciation, would also alter the calculation. See EPA's methodology for calculating break-even prices, available at http://www.epa.gov/methane/pdfs/methodologych4.pdf.

Key Uncertainties

Key concerns are the investment, capital cost, and regulatory environments.

Economic

- Value of natural gas, current and future.
- Future values of carbon.
- Value of hydrocarbon reserves, including EOR.
- Facilities' upgrade costs.

Logistical

- Regulatory environment (for permitting, for CCSR projects still being developed, for long-term monitoring requirements, conflicting state and federal regulations, etc.).
- Availability of resources—building materials, space in existing facilities, water, etc.
- Public acceptance of long-term CO_2 storage.

Long Term (after the project can no longer be classified as EOR)

- Is any leakage authorized? If so, how what amount/percentage?
- Long-term CCSR—How long is long term?
- Liability—Who is liable, and for how long?
- Logistical, legal, and royalty issues of cross-unit operations (if the reservoir for EOR is not in the same unit as Prudhoe).
- Time frame—How long to permit? How long to build?

Recommended Evaluation:

- Determine the relative benefits of various post-combustion capture techniques.
- Study CO_2 sequestration and EOR benefits within selected reservoirs. The choice of a final sequestration site should be based on safety, long-term storage capability, and economics. The more robust the economics, the faster this technology can be put into place. Since studies show that many oil fields in and around Prudhoe Bay would benefit from EOR, it should be considered wherever feasible in the planning of CCSR projects on the North Slope.

Specific Recommendations:

Risks and uncertainties in the following categories should be addressed:

- Maturity of technology.
- Costs for capture, transport, and sequestration.
- Potential for CO_2 leakage.
- Acidification of the reservoir and impact of corrosion on facilities.

Detailed analysis should cover:

- Pros and cons of capture facilities types and locations.
- Availability and costs for new or upgraded facilities, "parasitic" power requirements, space, and water requirements.
- Pros and cons of surrounding reservoirs for sequestration/EOR.
- Costs for drilling a well or wells that are not suitable for storage.
- Costs for down-hole well testing, maintenance, and repairs.
- Reservoir analysis and simulation studies.
- Value from a possible tax or carbon credits.
- Value from added reserves due to EOR.
- Estimates of CO_2 emissions avoided (includes additional emissions from capture, transport, and injection operations).
- Logistical issues related to construction and operations in an isolated arctic environment.
- Risk assessment for short-term and long-term storage.
- Costs for geological and geophysical studies for site monitoring.
- Impacts on EUR and conservation/production of resources (i.e., impact on EOR recovery of maximizing CO_2 storage).
- Regulatory requirements (e.g., EPA UIC program, other state and federal requirements).
- Monitoring requirements (pre-, during, and post-injection).

Additional Benefits and Costs

The 2002 estimate of CO_2 emissions related to O&G production at Prudhoe Bay is 9 MMt, almost half of all stationary GHG emissions in Alaska. About 2 MMt is related to the CGF, which provides the best logistical and economic environment for CCSR due to the size and density of the turbines.

In addition to the benefit of reducing CO_2 emissions, sequestering the CO_2 in a reservoir where it can be used to enhance the oil recovered has significant impact on the economics.

Benefits

- Significant economic advantages can be obtained if the initial CO_2 sequestration is partnered with EOR. Where EOR is effective, and reports indicate that many fields on the North Slope would benefit,[11] injection of CO_2 "washes out" residual oil left after initial production. While much of this CO_2 is cycled back to the surface with residual oil, a significant percentage remains trapped in the reservoir, even while active cycling is taking place. The rest of the CO_2 cycles up mixed with residual oil, is separated at the surface, and is re-injected into the reservoir. This cycling continues until EOR is no longer productive, at which point all the CO_2 in the reservoir remains sequestered. At that time, CO_2 could theoretically continue to be injected until injection pressure or some other operational limit is reached.
- Potential synergies in construction of CGF capture facilities with upgrades for energy efficiencies.

Costs

- Capital costs for capture, transport, and injection of CO_2.
- Parasitic energy—Additional fuel is burned (and additional GHGs created) to provide the power for capture, compression, dehydration, transport, and injection of the CO_2.
- Possible additional water requirements.
- Increased operating costs.
- Impact on global competitive standing if the U.S. cost structure is significantly higher than in countries without emission limits.
- The increased cost of energy impacts the overall cost of living for all.
- The higher cost structure may shorten ultimate field life, and EUR of hydrocarbons.

Feasibility Issues

- Capital requirements.
- Logistics, space, water availability for new facilities.
- State and federal (especially EPA) regulatory environments for CCSR projects are not yet established. Legal requirements and liability issues are unknown for long-term CO_2 storage. These have major impacts on cost and timing.
- Post-combustion CO_2 removal is not an established commercial process. Large-scale tests are currently ongoing through DOE.
- Other—See the Key Uncertainties section, above.

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[11] Advanced Resources International. April 2005. *Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Alaska.* Prepared for the U.S. Department of Energy, Office of Fossil Energy–Office of Oil and Natural Gas. Available at: http://www.adv-res.com/unconventional-gas-literature.asp.

Status of Group Approval

Approved.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.

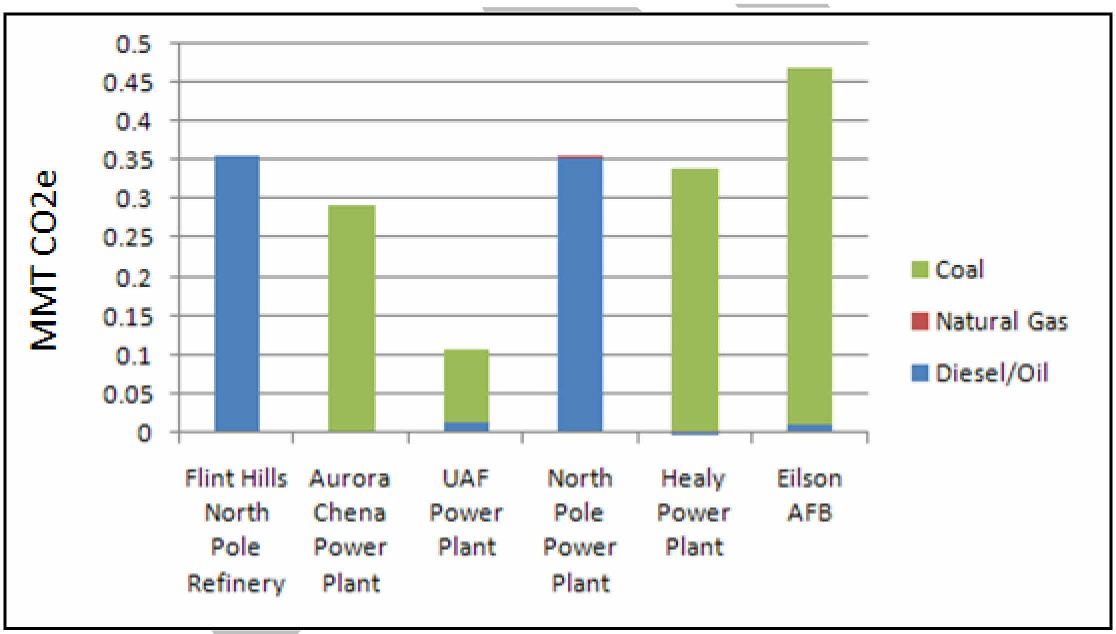
OG-8. Carbon Capture (From Exhaust Gas) and Geologic Sequestration Away From Known Geologic Traps

Policy Description

This policy relates to the technical and economic feasibility of CO_2 capture, transport, and geologic sequestration far from O&G infrastructure, in areas where a nearby storage reservoir is not proven. The capture and storage aspects, while similar in many aspects to those described in OG-7 for exhaust gas sources near existing Alaska O&G fields, differ in that there are no known reservoirs nearby. That means either that a long pipeline needs to be built to either the North Slope or Cook Inlet, or that an exploration program to prove up an appropriate storage reservoir needs to be executed.

Outside of the North Slope and Cook Inlet, the largest CO_2 sources are in interior Alaska, in and around the Fairbanks area. These sources encompass about 10% of Alaska's stationary sources of CO_2 (~2MMtCO_2e), with approximately 60% due to the burning of coal, and the rest related to the combustion of diesel fuel (Figure I-1).[12]

Figure I-1. 2002 CO_2e emissions from interior Alaska



CO_2e = of carbon dioxide equivalent; MMt = million metric tons.

Note: This option also deals with emissions outside the O&G sector.

[12] Alaska Department of Environmental Conservation. January 2008. "DRAFT—Summary Report of Improvements to the Alaska Greenhouse Gas Emission Inventory." (Includes Final Alaska GHG Inventory and Reference Case Projection.) Available at: http://www.climatechange.alaska.gov/docs/ghg_ei_rpt.pdf.

Policy Design

Goals:

- Initiate studies on the technical and economic aspects of implementation. The economic analysis should include design of appropriate financial incentives to responsibly encourage capital investments. The technical analysis should include the size and type of facilities modifications and the choice of appropriate combustion CO_2 capture technology, and should either search for nearby sequestration opportunities or plan for a pipeline to known reservoirs with proven seals.
- Because of the additional use of fuel required for capture, transport, and injection of CO_2, and the resultant GHG emissions related to its combustion, study the implementation of the policy in conjunction with, or after, all possible energy efficiencies that can be obtained. The less fuel burned overall, the less GHGs emitted.
- Encourage investment through incentives:
  - Financial:
    - Provide federal and state carbon credits.
    - Provide tax incentives for capital investment requirements.
  - Regulatory:
    - Simplify/streamline the regulatory environment.
    - Avoid overlapping state and federal regulations of GHG emissions and underground injections. Recommend coordinating with and participating in the development of federal regulations to ensure the regulations fit Alaska's conditions and to allow early implementation.
    - Study state permitting/regulatory personnel requirements. Establish policies to pay and retain sufficient qualified employees to cover additional workloads.

Timing: Early studies will facilitate the earliest possible implementation.

Implementation of CCSR in interior Alaska will require significantly more time and money than in and around established O&G fields, as either (1) an exploration program to establish the presence of a suitable geologic sequestration site in interior Alaska (most likely the Nenana Basin) would need to be performed, or (2) a long pipeline (to either Cook Inlet or the North Slope) would need to be built.

A commercial geologic sequestration project could not be permitted at this time, as the regulatory environment is still being developed.

Parties Involved:

- Consultants for conducting the study on technical and economic feasibility.
- Power-generating companies.
- Local landowners.
- State of Alaska (DNR, AOGCC, DEC, DOR, etc.) and other regulatory agencies (EPA, Federal Energy Regulatory Commission, RCA, etc.)

Other:

Geographic Focus: Fairbanks area in interior Alaska. Approximately 2 $MMtCO_2e$ are generated within approximately 100 miles of Fairbanks, but no proven geologic sinks are in that area. There is potential for a future coal gasification plant in Fairbanks, which would generate additional GHG emissions.

Research Needs:

Economic Research

- Model and recommend the most effective incentives. Model the effects on the economy and jobs with various scenarios. Involve Alaska DOR in this analysis.
- Research the long-term value of carbon, which could have a huge impact on the economics of these projects.

Technical Research

- Engage with and observe the DOE Phase III pilot project testing of various capture and sequestration technologies.
- Conduct a technical feasibility study of the different post-combustion CO_2 capture technologies.

Incentives: Financial, Permitting, Etc.

- Provide appropriate tax credits for investment in CCSR.
- Streamline the permitting process, which is critical for project turnaround.

Implementation Mechanisms

This policy using nearby sequestration cannot currently be implemented commercially under the current regulatory environment, though building a long pipeline is at least an understood, if time consuming, procedure. To minimize the time required for implementation, regulatory and capital investment concerns should be addressed immediately. A critical path is for the state to design incentives appropriate for capital investments, for operators to begin design of facilities and permitting needed to strip the CO_2 from the individual fuel exhaust streams, and to start either an exploration program to find a reservoir suitable for sequestration nearby, or the planning for a long pipeline. Capture technology studies should include space, power, and water requirements for each retrofitted facility. Finally, the state and operators should immediately start working on the complicated regulatory and permitting issues. Final economics will depend on the value of carbon. Financing CCSR projects will be sensitive to that value, and will be dependent on future cap-and-trade or carbon tax legislation.

Policies Needed

- State/local government permitting, as necessary, addressing issues beyond EPA UIC CO_2 sequestration rules.
  - Ownership issues—surface rights versus mineral rights versus pore space rights.
  - Long-term liability at sequestration sites.

    - Land-use regulations and requirements.
- Potential federal cap-and-trade legislation and ultimate EPA air quality regulations.

Related Policies/Programs in Place

Existing Policies

- Some tax incentives for CCSR exist in current federal legislation (carbon mitigation incentives included in the Emergency Economic Stabilization Act of 2008).

Policies Under Development

- EPA regulations regarding CO_2 underground sequestration.[13] The state may seek primacy for this activity upon final EPA rulemaking.
- EPA regulations, if any, and other federal laws regarding air quality, carbon tax or cap and trade, etc.

Types(s) of GHG Reductions

CO_2 removed from fuel gas post-combustion exhaust streams in interior Alaska, related to the burning of coal and diesel fuels, and injected into a nearby underground reservoir (yet to be discovered) or into established O&G fields in Cook Inlet or the North Slope.

Estimated GHG Reductions and Net Costs or Cost Savings

Potential emission savings through CO_2 capture from exhaust gases from coal and diesel burning sources in interior Alaska could be on the order of 2 $MMtCO_2$/yr.

A gross economics estimate, modeled using best guesses on capture, transport, and injection costs, as well as benefit from EOR, is $994/t. The estimate for expected yearly reduction in CO_2 emissions is 0.7 $MMtCO_2e$, and the estimate for total reduced emissions through 2025 is 8.0 $MMtCO_2e$. Due to the size and complexity of this kind of project, there is significant uncertainty in this number.

Due to the very large investments required, as well as timing and logistical constraints, large amounts of capital expenditures occur toward the end of the measurement period (2025). To avoid presenting a misleading number, capital and operating costs were amortized to 2035 when calculating $/$tCO_2$ of mitigated emissions. Large capital expenditures will be required by facility owners, as significant retrofitting of existing power-generating facilities will be needed. Depending on the type of capture technology chosen, additional water resources may also be required. For purposes of quantification, a 350-mile pipeline was assumed. No value was given to EOR at this time, as it is presumed that local sources would provide sufficient supply. In addition, significant amounts of fuel will be burned to power carbon capture, compression, transport, injection, and long-term monitoring.

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[13] New EPA Underground Protection Control Proposed rules for new Class VI Underground Protection Control have been out for comment. AOGCC is participating through the Interstate Oil and Gas Compact Commission and the Ground Water Protection Council. The state may apply for primacy when final rules are adopted. See www.epa.gov/ogwdw/uic/wells_sequestration.html for further information.

Data Sources: IPCC, DEC, AOGCC, O&G TWG members, API, *Oil and Gas Journal*, DOE, Center for Climate Strategies.

Quantification Methods: Policy options were modeled on generic, publicly available industry data from North Slope oil and gas operations. Thus, results must only be used to help direct more precise modeling, which would include, for example, taxes, royalties, individual oil and gas facility data, and specific engineering studies. Used a ground-up, first principles approach. Current emissions estimated using DEC Draft Inventory based on 2002 fuel burned. Bottom-up costs were estimated for each defined step from field experiences and literature, allowing some comparison and confirmation to similar independent studies—e.g., IPCC, etc. Quantification facilitated by ICF International.

Key Assumptions:

- All quantification assumes static activity based on 2008 production data.
- The capital and operating costs were amortized to 2035.
- A 350-mile pipeline is needed to transport CO_2 to a known reservoir capable of long-term CO_2 sequestration.
- A 5% discount rate was modeled. The cost-effectiveness estimates reported here are consistent with the methodology adopted by the MAG. The estimates can be interpreted as a rough indication of the ”social” cost per ton of emissions reduced, and so can be used to rank and compare different abatement options within and across the sector working groups for policy purposes. However, an estimate of the carbon price at which abatement would first become profitable could be higher than the cost-effectiveness modeled here. The cost-effectiveness estimates are calculated using a lower discount rate than is typically used by industry in determining the profitability of investments, and do not discount emission reductions. Consequently, the modeling may not accurately reflect the industry break-even price. Other factors, such as capital depreciation, would also alter the calculation. See EPA's methodology for calculating break-even prices, available at http://www.epa.gov/methane/pdfs/methodologych4.pdf.

Key Uncertainties

Key uncertainties are investment, capital cost, identification of a suitable reservoir for sequestration, and regulatory environment.

- Maturity of capture technology for coal and diesel combustion sources.
- Costs for capture, transport, and sequestration.
- Costs for geological and geophysical studies for site selection.
- Potential for CO_2 leakage.

Specific studies should address:

- Pros and cons of various capture technologies for coal or diesel power sites.
- Identification of basins with geologic sequestration potential.

- Identification and costs of geological and geophysical analysis required to provide confidence that the chosen formation will provide long-term geologic sequestration of injected CO_2 (e.g., test wells, down-hole well testing, maintenance and repairs, reservoir analysis, and simulation studies).
- Facilities requirements and costs (including additional power, space, and water).
- Logistics and costs for CO_2 pipelines, assuming a nearby sink can be found.
- Logistics and costs for CO_2 pipelines, assuming a long transport is required.
- Value from possible tax or carbon credits.
- Estimates of CO_2 emissions that could be avoided (including additional emissions from capture, transport, and injection operations).
- Logistical issues related to construction and operations in an extreme temperature environment.
- Risk assessment for long-term storage.
- Regulatory requirements (e.g., EPA UIC program, other state and federal requirements). A significant commitment from regulators will be needed to overcome existing hurdles in permitting and in the regulatory environment.
- Long-term monitoring needs (pre-, during, and post-injection).
- Analysis of costs and benefits of different mechanisms of carbon capture, from produced gas, and of removing carbon pre- and post-combustion. Options should be compared on a tCO_2-avoided basis (tCO_2 captured – tons CO_2 generated by capture, transport, and storage processes).
- Identification and cost estimate of additional infrastructure that would be required for transport and injection of CO_2 to injection sites.
- Identification and cost estimate of new or upgraded well construction if required for injection of potentially corrosive (if mixed with water) CO_2. Studies are needed to determine how well materials hold up to long-term exposure to various concentrations of CO_2.

Additional Benefits and Costs

The 2002 estimate of CO_2 emissions related to power generation in the Fairbanks area is 2 $MMtCO_2e$, about 10% of all the stationary GHG emissions in Alaska. Technically, a significant portion could be captured and injected if the appropriate capture technology could be built and a suitable storage site is found.

Benefits

- Incentive-driven potential to replace aging facilities if synergistic with capture and sequestration.
- Employment opportunities.

Costs

- Parasitic energy demand 20%–50% extra power requirements (burning more fuel, creating more GHGs), possible additional water requirements.
- The increased cost of energy impacts the overall cost of living for all.
- Increased operating costs.

Feasibility Issues

Reservoir selection will be a challenge in interior Alaska, as currently there are no identified sequestration sites. Geologically, Fairbanks is underlain by metamorphic rocks that are highly sheared and faulted and would have very limited, if any, CO_2 trapping capacity. The nearest coal-bearing sedimentary rock is in the Nenana Basin to the southwest, which is likewise highly deformed. Still unknown is the potential in the Nenana Basin for saline reservoir storage, though an Exploration License is currently active in that area. An O&G exploration well (currently being planned) could add much-needed information to answer whether there is prospective CO_2 geologic sequestration potential in a saline reservoir. To confirm sequestration potential, additional wells, seismic data acquisition, and computer modeling would likely be required before proof of ability to sequester CO_2 long term would be established. With current information, however, the ability of a rock to sequester CO_2 for any length of time is completely unknown.

Possible long-term sequestration potential exists in unminable coal seams known to exist in interior Alaska, but this technology has significant obstacles, and long-term injection into coal seams has not yet proven feasible, especially in areas where permafrost can be expected.

Finally, risk assessment and a long-term monitoring program will be required for all sequestration projects. EPA is currently working on regulations that will be applied to sequestration projects, but long-term (time frame still to be defined) post-injection monitoring will certainly be an expectation for any sequestration site.

Other feasibility issues include:

- Costs—Can capital be raised?
- Available technology, technology maturity.
- Legal issues—Will long-term injection be approved?
- Liability—Who is responsible long term?
- Ownership of pore space.
- Conflicting regulatory requirements.
- Time frame—How long to permit? How long to build?
- Logistics—space for new facilities and availability of new required equipment.
- Public acceptance of long-term storage
- Availability of resources (water, power).
- Public acceptance—"Not in my back yard" (NIMBY) concerns.

Status of Group Approval

Approved.

Level of Group Support

Unanimous consent.

Barriers to Consensus

None.