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Viability of a Large-Scale Carbon Capture & Sequestration Network In Pennsylvania

Prepared by the Clinton Climate Initiative



November 1, 2009

FOREWORD

Global warming is the most significant environmental problem facing the world today - one that threatens our environment, our economy, public health, and our way of life. The overwhelming scientific consensus is that the earth's climate is changing rapidly due to the atmospheric buildup of human-generated, heat-trapping emissions, primarily carbon dioxide pollution from power plants and automobiles.

Pennsylvania produces more greenhouse gas emissions than 105 developing countries combined. According to the National Environmental Trust, Pennsylvania emits 1 percent of the entire planet's human-caused global warming gases, and ranks third among all states in global warming emissions. The Commonwealth therefore has a special responsibility to take common sense, meaningful action to reduce global warming pollution.

Pennsylvania is also the 4th largest coal producing state in the United States. More than 40 percent of the state's electricity is coal-fired, and 30 percent of the energy generated in Pennsylvania is exported to other states. If the Commonwealth is to reduce its global warming emissions, it must find ways to burn coal as cleanly as possible.

How will the state's economy adapt under the imposition of federal carbon emission constraints? What steps does the Commonwealth need to take now to ensure environmental and economic sustainability as the world confronts the challenges of climate change?

There is certainly no single answer to those questions. Clearly, a portfolio of approaches, policies, and technologies will be required to confront the challenges of a carbon constrained world. Governor Rendell and the General Assembly have made Pennsylvania a national leader in renewable energy development and in energy conservation and energy efficiency. Those initiatives will significantly reduce the Commonwealth's emissions of global warming gases. But there is more work to do.

One technology that offers great promise and that is particularly appropriate for consideration by the Commonwealth is carbon capture and sequestration (CCS) - a process of capturing carbon dioxide emissions from coal-fired electric power plants and other industrial facilities to prevent them from going into the atmosphere, and then storing them permanently underground in safe geological formations.

According to the Midwest Regional Carbon Sequestration Partnership (MRCSP),¹ Pennsylvania has an estimated geologic capacity to store hundreds of years' worth of carbon emissions at present rates. If that resource can be proven, and appropriately and safely developed along with all of the other technological requirements of CCS, the Commonwealth may be able to substantially reduce its global warming emissions and protect our environment, our economy, and public health - while preserving its position as a net energy exporter and creating jobs in the process.

The focus of this report, prepared *pro bono* by Worley Parsons², Spectra Energy³, Climate Change Capital⁴ and the Clinton Climate Initiative⁵ as the third of three reports required of DCNR by Act 129 of 2008, is an

¹ http://216.109.210.162/

² http://www.worleyparsons.com/Pages/default.aspx

³ http://www.spectraenergy.com/

⁴ http://www.climatechangecapital.com/home.aspx

assessment of the capital and operating costs associated with the development of a large-scale, integrated commercial CCS network in Pennsylvania. It follows a report issued by DCNR on May 1, 2009 on *Geologic Carbon Sequestration Opportunities in Pennsylvania*⁶ and accompanies a separate risk assessment study of a state CCS network.

These reports, along with DCNR's *Report of the Carbon Management Advisory Group* published in May, 2008,⁷ are a part of DCNR's continuing contribution to the formation of Pennsylvania's policy response to the challenges of reducing the Commonwealth's global warming emissions and building a sustainable economy for our state.

There are many unanswered questions and concerns about an emerging technology like CCS. Given the magnitude of the challenge of reducing carbon dioxide emissions to avoid catastrophic impacts of climate change, it is essential that we explore the possibilities with the sense of urgency that the problem demands.

It has been an honor to work with the leadership and staff of the William J. Clinton Foundation and the outstanding team of committed professionals at the Clinton Climate Initiative. CCI brought together the private companies who readily agreed to assist the Commonwealth in this important effort. We are indebted to the public-spirited professionals at Worley Parsons, Spectra Energy, and Climate Change Capital.

This report would not have been possible without the cooperation and assistance of CONSOL Energy, Allegheny Energy, PPL, Midwest Edison, RRI Energy, and US Steel.

I also want to acknowledge and thank the women and men of DCNR's Bureau of Topographic and Geologic Survey for their continued excellence and professionalism in assisting in the preparation of this report.

John Quizley

John Quigley Acting Secretary Pennsylvania Department of Conservation and Natural Resources

⁵ http://www.clintonfoundation.org/what-we-do/clinton-climate-initiative/

⁶ http://www.dcnr.state.pa.us/info/carbon/mastercstareport2.pdf

⁷ http://www.dcnr.state.pa.us/info/carbon/documents/final-report-050708.pdf

1. EXECUTIVE SUMMARY

Background

The Commonwealth of Pennsylvania is interested in exploring the possibility of a large-scale, commercial carbon capture and sequestration ("CCS") network located within the state.

The conclusions in this report are the result of six months of analysis undertaken by the Commonwealth of Pennsylvania with the assistance of Worley Parsons, Spectra Energy, Climate Change Capital and the Clinton Climate Initiative. Additional cooperation was provided by CONSOL Energy, Allegheny, PPL, Edison, RRI Energy, GE and US Steel.

The objective of this report is to assess the technical and economic viability of an integrated "early mover" CCS network within Pennsylvania. The deployment of this integrated network could potentially lower the costs for individual power plants of deploying carbon capture and storage through the use of shared infrastructure, the reduction of regulatory uncertainty and the provision of public incentives. Once scale is achieved, new generation assets, enabled for carbon capture, can be phased in and linked to the network over time, at lower cost and involving less public subsidy.

The Process

This report focuses on the technical and economic aspects of the first phase of such a network — the retrofit of six coal-fired power plants in central and southwest Pennsylvania. Later phases of a CCS network would involve the integration of additional power plants, industrial facilities, and new-build generation and the creation of transport and storage facilities.

For this report, Worley Parsons, a global engineering firm with significant experience in both the power industry and CCS, concluded detailed assessments of current plant configurations at existing generation facilities. The objective was to determine the capital equipment and modifications required to capture and compress a targeted level of CO2 emissions at each plant. Current market costs for equipment were used, based on commercially-available capture technology (see Appendix for a discussion of current CCS technology). These assessments also include the estimated impact on plant performance post-capture.

Spectra Energy, a leading US-based natural gas transport and infrastructure company, conducted a similar assessment of the infrastructure and operational requirements for a CO2 pipeline and injection system.

Conclusions

The initial assessment indicates that the capture and transport components of a Pennsylvania CCS network would be competitive compared to both proposed and existing international CCS projects. Preliminary cost and technical analysis leads to a range in total capture and compression costs of \$43 - \$69/ton, depending on the technology utilized. The costs of transport and storage infrastructure range from \$3.3 - \$4.2/ton. These costs are particularly sensitive to volumes of CO2 transported and stored. Full-chain CCS costs in Pennsylvania are low as compared to other public projects, in part due to the high volumes of CO2 that can potentially be sequestered. In order to be economically viable at early stages, a CCS network would still require appropriate levels and forms of public support. A number of project risks (i.e. technology, regulatory, financial, community) would also need to be borne by Government.

Cost of capture for various retrofit technologies		Cost of transport and storage for various volume levels		
Retrofit plant	Capture cost per tonne captured (real)	Volumes transported and stored	Transport and storage cost per tonne stored (real)	
Armstrong	\$ 55 – 83 /tonne	2.0 Mton/yr	\$ 84 /tonne	
Montour	\$ 43 – 54 /tonne	5.9 Mton/yr	\$ 28 /tonne	
Seward	\$ 38 – 49 /tonne	11.4 Mton/yr	\$ 15 /tonne	
HomerCity	\$ 49 – 67 /tonne	19.3 Mton/yr	\$ 9 /tonne	
Conemaugh	\$ 45 – 60 /tonne	43.1 Mton/yr	\$ 4 /tonne	
Keystone	\$ 46 - 61 /tonne	49.9 Mton/yr	\$ 3 /tonne	

Preliminary cost analysis for capture, transport and temporary storage:

Ranges indicate capture cost sensitivity, i.e. as CAPEX and OPEX assumptions are varied by -30% (low case) and +30% (high case)

Total Capital Expense required for Phase 1 of an Early-User Network (+/- 40% acc.)

- Capture + compression: \$6,900 m
- Transport + storage: \$1,200 m

Annual operating expense required for Phase 1 of an Early-User Network (+/- 40% acc.)

- Capture + compression: \$260 m
- Transport + storage: \$9 m

2. CONCEPT SUMMARY

Carbon Capture and Storage ("CCS") technologies allow for the capture, transport, and underground sequestration of the carbon dioxide produced from the burning of fossil fuels and other industrial processes. While individual CCS pilot projects capturing and storing small quantities of CO_2 do exist, these are inherently expensive per unit of carbon captured and often lack the potential for scale up that would ensure commercial deployment.

A network approach to CCS build-out, where entire CCS systems are developed around a cluster of emitters sharing a common transportation and storage structure, may help accelerate deployment. CCS networks, unlike small-scale single installation plants, leverage investment by capitalizing on economies of scale and shared infrastructure, while designing for scale-up at inception. A network approach may also diversify CO_2 sources, capture technologies and storage/offtake profiles.

The plan put forth by the Commonwealth of Pennsylvania envisages an initial network capture rate of over 20-30 million tons of CO_2 per year, from up to ten power plants and industrial facilities, largely concentrated in the southwest corner of the state. These emissions would then be transported over a network of existing and new-build pipelines and stored. In time, and with sufficient scale-up, the goal would be to enable a network build-out that could eventually capture over 100 million tons of CO_2 from stationary power. This would mean that 70% of the state's emissions per year from electricity generation, as well as one-third of total emissions, would be captured and sequestered with no damage to the environment.

The core of the "early-user" network includes the retrofit of six large coal-fired facilities. The locations of the CO_2 sources and their historical annual CO_2 emissions are presented in the figure below. All of the sources included in this phase of analysis are coal-fired power generating stations. Together, these six facilities release 50+ million tons of CO_2 per year (over 15% of Pennsylvania's total emissions) and provide a substantial amount of the Commonwealth's electricity needs. Five sources (83% of total) are located in close proximity to one another in Indiana and Armstrong Counties. The initial plants included in this report, chosen in consultation with plant owners, are:

- Armstrong (Allegheny Energy)
- Montour (PPL)
- Homer City (Midwest Edison)
- Seward (RRI Energy)
- Keystone (RRI Energy)
- Conemaugh (RRI Energy)

At initiation, this network could capture 20-30 million tons of CO2 per year, with the potential to scale up to 50-60 million tons per year by 2020. Additionally, the network could be sized to allow additional capture-ready new-build generation facilities to take advantage of shared infrastructure and capture and sequester their emissions. To proceed from this stage, near-term requirements

would include detailed FEED studies on the associated plants, further assessment of CO2 transmission corridors, sequestration site characterization and legal and financial advisory services.



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3. CO₂ CAPTURE ANALYSIS

Technical Evaluation of PA CCS Initiative Host Sites

This section displays a summary of results on carbon capture analysis, provides a description of the PA CCS Network host sites, discusses carbon capture technology applicability, retrofit approaches and impacts on the existing plant systems, and explains rationale for selecting design configurations. The carbon capture retrofit impacts are quantified and presented in this section in terms of plant electrical output, thermal efficiency, CO_2 emissions, and retrofit investments.

Summary

Cost analysis results

March 2009 1000 US dollars	Armstrong	Montour	Seward	Homer City	Conemaugh	Keystone
Total Retrofit Costs	\$581,000	\$733,000	365,000	\$2,050,000	\$1,600,000	\$1,600,000
Additional Annual O&M	\$21,000	\$26,000	10,500	\$80,000	61,000	63,000
CO₂ t/year Captured	2,300,000	7,500,000	3,300,000	12,500,000	11,600,000	11,500,000

Note: Estimates of annual captured CO2 are based on capacity factor of 0.8 for all base loaded plants.

Approach

This analysis represents a broad engineering assessment for the projects that provides conceptual level information to support system planning studies, preliminary cost and economic assessments, and plant site evaluations. The conceptual design engineering presented in this report lays the technical foundation for selecting design concepts and equipment, and defines the key design features, functional systems and structures, system and equipment design constraints, plant performance, and plant costs. This report focuses on developing the preliminary technical information to support project planning and analysis. As the projects evolve, a follow-on detailed design process will be required to facilitate continued feasibility assessment, permitting/licensing, equipment procurement, construction, and operation of the new facility.

A retrofit approach was selected for enabling carbon capture at the PA CCS Network host sites. CCS retrofits involve the addition of components or accessories to a previously built facility. Alternatively, a repowering approach involves the replacing of the entire technological island of a plant (for example: a boiler, or a steam turbine) with new equipment. As such, retrofits imply the lowest capital cost modification to an existing plant to facilitate new design goals. Retrofitting also requires the selection of design configurations that would utilize the existing plants' equipment within their current design constraints to the greatest extent possible.

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	Armstrong	Montour (1)	Seward	HomerCity	Conemaugh	Keystone
Technical / operational assumption	ns					
Capture technology	PowerspanECO2	MEA	Oxycombustion	MEA	MEA	MEA
Net power capacity pre retrofit	341 MW	1,477 MW	524 MW	1,884 MW	1,700 MW	1,700 MW
Net power capacity post retrofit	262 MW	1,171 MW	392 MW	1,304 MW	1,178 MW	1,178 MW
Total CO ₂ produced pre retrofit	1,908 lb/MW h	1,793 lb/MWh	1,005,318 lb/h	3,967,704 lb/h	3,669,548 lb/h	3,618,072 lb/h
Total CO ₂ produced post retrofit	1,908 lb/MW h (2)	1,793 lb/MWh (2)	1,009,540 lb/h	3,967,704 lb/h	3,669,548 lb/h	3,618,072 lb/h
Total CO ₂ emitted post retrofit	124 lb/MWh	667 lb/MW h	63,656 lb/h	396,770 lb/h	366,954 lb/h	361,808 lb/h
Cost assumptions						
Retrofit CAPEX	\$581m	\$733m	\$365m	\$2,050m	\$1,600m	\$1,600m
Additional annual O&M	\$21m	\$26m	\$10.5m	\$80m	\$61m	\$63m

Key technical and cost assumptions

(1) Montour calculated based on day-load data (as provided by company)

(2) CO₂ produced post retrofit assumed to equal the amount produced pre retrofit (as per data provided by company)

Economic impact of proposed Pennsylvania CCS Network

			Cost of capture		
	volumes ⁽¹⁾	capture ⁽¹⁾	In \$ per tonne captured	in \$m per year	
Armstrong	2.0 Mton/yr	95%	\$69/tonne	\$136m	
Montour (2)	5.9 Mton/yr	71%	\$49/tonne	\$289m	
Seward	3.0 Mton/yr	94%	\$43/tonne	\$130m	
HomerCity	11.4 Mton/yr	90%	\$58/tonne	\$658m	
Conemaugh	10.5 Mton/yr	90%	\$53/tonne	\$552m	
Keystone	10.4 Mton/yr	90%	\$54/tonne	\$554m	

(1) Captured volumes and rates are calculated using the following equation:

Total CO_2 captured post retrofit = Total CO_2 produced post retrofit - Total CO_2 emitted post retrofit

(2) Montour calculated based on day-load data (as provided by company)

Assumptions

Timing

- o Start of operations: 2013
- Plant life: 30 years
- o Valuation date: 2009
- CAPEX schedule
- Year 1: 20%
- Year 2: 45%
- Year 3: 35%
- Power pricing assumptions
- o PJM Western Hub

Macroeconomic assumptions

- o Inflation: 2% (2009 basis)
- o Tax rate: 35%
- Accelerated depreciation for tax purposes

Financing assumptions

- o 100% equity
- o Blended cost of capital: 10%

Methodology

The cost of capture ($\$ /ton captured) is based on financial modeling. The total CO₂ captured postretrofit is equal to the total CO₂ produced post retrofit minus the total CO₂ emitted post retrofit. All retrofitted plants were modeled in comparison to the plants at their initial state (i.e. without CO₂ capture). The revenues/costs considered are incremental losses/gains as compared to the reference case. Finally, the incremental changes in revenues and costs reflect the fact that additional units and energy are required for capture activities. The cost of capture is then calculated as the equivalent payment that would need to be received by the plant in order for the retrofit to represent an investment with a net present value of zero (at 10% discount rate).

Cost Estimates Methodology

The Total Plant Cost (TPC) and Operation and Maintenance (O&M) cost estimates are developed for each of the CO_2 systems in the study. The estimates will carry an accuracy of ±50 percent, consistent with the level of information appropriate for a screening study of the various power technologies. The estimates are developed as factored estimates based on an in-house database and conceptual estimating models for the capital cost and O&M cost estimates. Where possible, costs are further calibrated using a combination of adjusted vendor-furnished data and actual cost data from recent design and design/build projects. All capital and O&M costs are presented as "overnight costs" expressed in March 2009 US dollars.

Capital Costs: The capital cost estimates for each design case are developed using Worley Parsons in-house database and conceptual estimating models. This database and the respective models are maintained by Worley Parsons as part of a commercial power plant design base of experience for similar equipment in the company's range of power and process projects. A reference bottoms-up estimate for each major component provides the basis for the subsequent comparisons and easy modification when comparing between specific case-by-case variations. Key equipment costs for

each of the cases are calibrated to reflect recent quotations and/or purchase orders for other ongoing in-house power or process projects.

Scope

Capital costs are presented at the TPC level. TPC includes equipment (complete with initial chemical and catalyst loadings), materials, direct and indirect labor, engineering and construction management, and process and project contingencies. Owner's costs are excluded.

Price Escalation

A significant change in power plant cost occurred in recent years due to the significant increases in the pricing of equipment and bulk materials. This estimate includes these increases.

Exclusions

The capital cost estimate includes all anticipated costs for equipment and materials, installation labor, professional services (Engineering and Construction Management), and contingency. Escalation to period-of-performance, all taxes with the exception of payroll taxes, labor incentives in excess of a 5 day/40 hour workweek, additional premiums associated with an EPC contracting approach, and owner's costs including, but not limited to, land acquisition and right-of-way, permits and licensing, royalty allowances, economic development, project development costs, allowance for funds-used-during construction, legal fees, owner's engineering, preproduction costs, furnishings, and owner's contingency are all excluded from capital costs.

Contingency

Both the project contingency and process contingency costs are costs that are expected to be spent in the development and execution of the project that are not yet fully reflected in the design. It is industry practice to include project contingency in the TPC to cover project uncertainty and the cost of any additional equipment that would result during detailed design. Likewise, the estimates include process contingency to cover the cost of any additional equipment that would be required as a result of continued technology development.

Operations and Maintenance (O&M) costs are the production costs or operating costs and related maintenance expenses (O&M) pertaining to those charges associated with operating and maintaining the power plants over their expected life. These costs include operating labor, material and labor maintenance, administrative and support labor, consumables, and waste disposal. There are two components of O&M costs — fixed O&M, which is independent of power generation, and variable O&M, which is proportional to power generation.

Operating Labor

Operating labor cost was determined based on of the number of operators required for each specific case on a ratio basis from historical data. The average base labor rate used to determine annual cost is \$35/hr. The associated labor burden is estimated at 30 percent of the base labor rate.

Maintenance Material and Labor

Maintenance cost was evaluated on the basis of relationships of maintenance cost to initial capital cost. This represents a weighted analysis in which the individual cost relationships were considered for each major plant component or section.

Administrative and Support Labor

Labor administration and overhead charges are assessed at rate of 25 percent of the burdened operation and maintenance labor.

Consumables/Waste Disposal

The cost of consumables are determined on the basis of individual rates of consumption, the unit cost of each specific consumable commodity, and the plant annual operating hours. Other consumables were evaluated on the basis of the quantity required using reference data. Initial fills of the consumables, fuels and chemicals, are different from the initial chemical loadings, which are included with the equipment pricing in the capital cost. Waste quantities and disposal costs were determined / evaluated similarly to the consumables.

ARMSTRONG STATION

Allegheny Energy's Armstrong power generating station is situated on a 210-acre site on the Allegheny River near Kittanning, PA. It is comprised of two bituminous coal fired units with a name plate capacity of 180 MWe each. Armstrong station is an intermediate load station, and both units are run most of the time when they are available. Armstrong is dispatched at approximately 90 MWe and 160 MW net during the day, and at approximately 60 MWe net overnight. NOx and SOx emissions at the Armstrong station are currently not controlled. It is believed that upon addition of NOx, and SOx control equipment, the Armstrong station would be dispatched in base load. Although any of the preselected carbon capture technologies could be applied to enable carbon capture at the Armstrong station, Powerspan ECO_2 technology is integrated with the ECO process, which provides NOx, and SOx control. ECO's multi pollutant control capability makes it well suited for the Armstrong station situation. Thus, ECO_2 has been selected for carbon capture retrofit of Armstrong Units 1 and 2.

A proposed configuration of the retrofitted Armstrong station is presented below. The integrated $ECO-ECO_2$ system is envisioned to treat flue gas from both units, while capturing 90% of CO_2 ,

98% of SOx and 67% of NOx in the flue gas. Slip streams of low-pressure steam are extracted from the existing steam turbine LP crossover pipelines of both units and directed into a common steam header and delivered for the solvent regeneration. Each of the existing feedwater systems is modified to recover thermal energy from the CO_2 compression and reduce the heat sink load of the retrofitted plant. Condensate slip streams from both units are collected into a common header, and directed to compressor inter-stage coolers. The heated condensate from inter-stage coolers is then returned to each of the two units' feedwater systems.

The Armstrong retrofit includes a new ECO-SO₂ absorber system, including a co-product plant, a new ECO₂ absorber system, a new CO₂ compression and dehydration system including inter-stage water coolers/condensate heaters, a new booster fan, a new ammonium sulfate handling system, a new ammonia storage and handling system, a new auxiliary evaporative mechanical cooling tower, and a new wet stack. The scope of modifications to existing systems includes modifications to the flue gas ducts, to the existing medium voltage electric system to support operation of the CO₂ capture and compression systems, and to the condensate/feedwater system to recover thermal energy from CO₂ compression and flue gas.

The projected impact of the Armstrong retrofit is presented below:

Parameter	Units	Pre Retrofit	Post Retrofit
Plant Gross power	kWe	360,000	346,200
Plant Aux power	kWe	19,440	19,440
ECO/ECO ₂ /Comp. aux. power	kWe	NA	65,057
Plant net power	kWe	340,560	261,703
Plant net heat rate	Btu/kWh	9,623	12,522
Plant net efficiency	%	35.5%	27.2%
Emissions			
	lb/MWh		
CO ₂	net	1,908	124
SOx	lb/MMBtu	6.53	0.13
NOx	lb/MMBtu	0.3	0.1

Armstrong Station Performance:



BLOCK FLOW DIAGRAM OF THE RETROFITTED ARMSTRONG STATION PLANT

MONTOUR

PPL's Montour station is located in Washingtonville, PA. It is comprised of two bituminous coal fired supercritical units, each rated at a nominal 780 MWe. Units are base loaded during peak winter and peak summer seasons at about 780 MWe gross. During off-peak seasons, units 1 and 2 operate in intermittent mode (780 MWe gross during the day and 425 MWe gross overnight). Units 1 and 2 support grid area regulation. Their load may vary ± 25 MWe, at a rate of approximately 5 MWe per minute. Both units are equipped with SCR and FGD systems. FGD systems for Unit 1 and Unit 2 were commissioned during 2008. The FGD system is of limestone forced oxidation type and can achieve 5-20 ppmv of SO₂ emissions. It is typically run at approximately 200 ppmv SO2 emissions for economic reasons.

Given the intermittent load operation of the Montour station and the very low sulfur content achievable in the flue gas, MEA, Chilled Ammonia, or KS solvents technology would be suitable for a carbon capture retrofit at the Montour station. The MEA absorption process has been envisioned in this study owing primarily to the availability of reliable performance and cost information for the MEA technology.

The MEA configuration of the retrofitted Montour station is presented below. In the retrofitted plant, each unit is equipped with a dedicated MEA solvent based absorption-regeneration system sized to capture 90% of CO_2 in the flue gas stream equivalent to a typical night time net power load of 410 MWe. Flue gas is extracted from the existing flue gas ducts downstream of the existing FGD unit, and then scrubbed in the MEA absorber. Approximately 90% of the CO_2 in the MEA feed gas is captured. During daytime operation, the balance of the flue gas is transported to the existing stack via existing flue gas ducts. This configuration should permit continuous operation in an intermittent load while supporting grid area regulation. Slip streams of low-pressure steam are extracted from the existing steam turbine LP crossover pipeline and then expanded in a new backpressure turbine to a pressure as required for the MEA solvent regeneration. The backpressure turbine is equipped with a controlled pressure extraction to provide steam at a constant pressure for the MEA reclaim. The existing feedwater system of each unit is modified to recover thermal energy from the CO_2 compression and reduce heat sink load of the retrofitted plant. Condensate slip stream is directed to compressor inter-stage coolers, and the heated condensate from inter-stage coolers is returned to the feedwater system.

The Montour retrofit includes a new regeneration system for MEA absorption, a new CO_2 compression and dehydration system including inter-stage water coolers/condensate heaters, a new backpressure steam turbine generator, a new booster fan, and a new MEA makeup and handling system. The scope of modifications to existing systems includes modifications to the flue gas ducts, to the existing high voltage electric system to accommodate operation of a new steam turbine generator, to the existing medium voltage electric system to support operation of the CO_2 capture and compression systems, and to the condensate/feedwater system to recover thermal energy from CO_2 compression and flue gas.

The projected impact of the Montour retrofit on plant performance is presented below:

Montour Station Unit Performance:

		Pre	Retrofit	Post Retrofit	
Parameters	Units	Day	Night	Day	Night
		Load	Load	Load	Load
Unit Gross Power					
Main STG	MWe	780	425	673.70	493.9
Back Pressure STG	MWe	0	0	17.6	17.6
Total		780	425	691.3	511.5
Auxiliary Load					
Plant	MWe	41.3	31.5	41.33	37.1
CO ₂					
Capture/Compression	MWe	0	0	64.4	64.4
Total		41.34	31.45	105.78	101.51
Net Unit Power	MWe	738.7	393.6	585.5	410
Net Unit Heat Rate	Btu/kWh	9,012	10,099	11,721	13,294
Net Unit Efficiency	%	37.9%	33.8%	30.0%	26.8%
	lb/MWh				
CO ₂ Emissions	net	1,793	2,009	667	253



BLOCK FLOW DIAGRAM OF THE RETROFITTED MONTOUR PLANT

HOMER CITY

The Homer City Generating Station is a 2-GW power station located on a 2,400-acre site near Homer City, Indiana County. It is comprised of three pulverized coal fired units. Units 1 and 2, rated at 650 MWe gross (620 MWe net), began operation in 1969. Unit 3, rated at 692 MWe (650 MWe net) nameplate capacity, was launched in 1977. The stack on Homer City-3 is the tallest on any power station in the USA at 1,216 ft. In 2005, the plant's annual CO₂ emissions were reported at 13.4 million tons per year, with an annual capacity factor of 0.77.

The MEA absorption process is envisioned as the retrofit technology for Units 1, 2 and 3 owing primarily to availability of reliable performance and cost information for the MEA technology. Configuration of the retrofitted Homer City station units is similar to the Montour station retrofit (see below), except it assumed that Homer City units are base-loaded and the new carbon capture system is sized to process 100% of flue gas flow rate exiting boilers. In the retrofitted plant, each unit is equipped with a dedicated MEA solvent based absorption-regeneration system sized to capture 90% of CO₂ in the flue gas stream equivalent to unit maximum continuous rated capacity. Flue gas at the existing FGD units is pre-polished and scrubbed in the MEA absorber. Approximately 90% of the CO₂ in the MEA feed gas is captured.

Slip streams of low-pressure steam are extracted from the existing steam turbine LP crossover pipeline expanded in a new backpressure turbine to a pressure as required for the MEA solvent regeneration. The backpressure turbine is equipped with a controlled pressure extraction to provide steam at a constant pressure for the MEA reclaim. The existing feedwater system of each unit is modified to recover thermal energy from the CO_2 compression and reduce heat sink load of the retrofitted plant. Condensate slip stream is directed to compressor inter-stage coolers. The heated condensate from inter-stage coolers is returned to the feedwater system.

The Homer City retrofit includes a new regeneration system for MEA absorption, including a sulfur polishing unit, a new CO_2 compression and dehydration system including inter-stage water coolers/condensate heaters, a new backpressure steam turbine generator, a new booster fan, and a new MEA makeup and handling system. The scope of modifications to existing systems includes modifications to the flue gas ducts, to the existing high voltage electric system to accommodate operation of a new steam turbine generator, to the existing medium voltage electric system to support operation of the CO_2 capture and compression systems, and to the condensate/feedwater system to recover thermal energy from CO_2 compression and flue gas.

The projected impact of the Homer City retrofit on plant performance is presented below.

Parameter	Units	Pre Retrofit	Post Retrofit
Gross Power	MWe	1992	1639
Net Power	MWe	1884	1304
Auxiliary load	MWe	108	324
Net efficiency HHV	%	35.5%	24.6%
CO ₂ Produced	lb/h	3,967,704	3,967,704
CO ₂ Captured	lb/h	0	3,570,934
CO ₂ Emitted	lb/h	3,967,704	396,770
	lb/MWh		
CO ₂ Specific emissions	net	1,972	304

Retrofit Impact on Homer City Plant Performance

CONEMAUGH

Conemaugh is a coal-fired electric generating station featuring two pulverized coal supercritical boilers that total 1,800 megawatts gross. The facility is located in Indiana County near New Florence, Pennsylvania. It is jointly owned by a group of eight co-owners. The 2008 capacity factor for Conemaugh unit 2 was reported as at least 82%. Conemaugh Unit 1 had some technical issues in 2008, and its capacity factor was around 65%. It expected that Conemaugh Unit 1 will be dispatched at the same level as Unit 2 in the future. Annual CO_2 emissions for 2008 were reported at 4.7 million tons for Unit 1, and 6.1 million tons for Unit 2. In 2005, the plant's annual CO_2 emissions were reported at 12.6 million tons per year, with an annual capacity factor of 0.79.

The MEA absorption process is envisioned as the retrofit technology for Units 1 and 2, owing primarily to the availability of reliable performance and cost information for the MEA technology. The configuration of the retrofitted Conemaugh station units is similar to the Montour station retrofit (see below), except it assumed that Conemaugh units are base loaded and that the new carbon capture system is sized to process 100% of flue gas flow rate exiting boilers. In the retrofitted plant, each unit is equipped with a dedicated MEA solvent-based absorption-regeneration system sized to capture 90% of CO₂ in the flue gas stream equivalent to unit maximum continuous rated capacity. Flue gas at the existing FGD units is pre-polished and scrubbed in the MEA absorber. Approximately 90% of the CO₂ in the MEA feed gas is captured.

Slip streams of low-pressure steam are extracted from the existing steam turbine LP crossover pipeline and then expanded in a new backpressure turbine to a pressure as required for the MEA solvent regeneration. The backpressure turbine is equipped with a controlled pressure extraction to provide steam at a constant pressure for the MEA reclaim. The existing feedwater system of each unit is modified to recover thermal energy from the CO_2 compression and reduce heat sink load of the retrofitted plant. Condensate slip stream is directed to compressor inter-stage coolers, and the heated condensate from inter-stage coolers is returned to the feedwater system.

The Conegmaugh retrofit includes a new regeneration system for MEA absorption, including a sulfur polishing unit, a new CO_2 compression and dehydration system including inter-stage water coolers/condensate heaters, a new backpressure steam turbine generator, a new booster fan, and a new MEA makeup and handling system. The scope of modifications to existing systems includes modifications to the flue gas ducts, to the existing high voltage electric system to accommodate operation of a new steam turbine generator, to the existing medium voltage electric system to support operation of the CO_2 capture and compression systems, and to the condensate/feedwater system to recover thermal energy from CO_2 compression and flue gas.

The impact of the Conemaugh retrofit on plant performance is presented below.

Parameter	Units	Pre Retrofit	Post Retrofit
Gross Power	MWe	900	740
Net Power	MWe	850	589
Auxiliary load	MWe	50	150
Net efficiency HHV	%	35.9%	24.9%
CO ₂ Produced	lb/h	1,834,774	1,834,774
CO ₂ Captured	lb/h	0	1,651,296
CO ₂ Emitted	lb/h	1,834,774	183,477
	lb/MWh		
CO ₂ Specific emissions	net	1,949	312

Retrofit Impact on Conemaugh Station Unit Performance:

KEYSTONE

Keystone is a coal-fired electric generating station featuring two pulverized coal supercritical boilers with total name plate capacity of 1,700 MWe. The facility is located on a 1,459-acre site in Indiana and Armstrong counties near Shelocta, Pennsylvania. It is jointly owned by a group of seven coowners. The Keystone station configuration is similar to that of the Conemaugh station. The 2008 capacity factor for Keystone Units 1 and 2 was reported as at least 82, and annual CO_2 emissions for 2008 were reported at 6.7 million tons for Unit 1 and 6.9 million tons for Unit 2. In 2005, the plant's annual CO_2 emissions were reported at 13 million tons per year, with an annual capacity factor of 0.82.

The MEA absorption process is envisioned as the retrofit technology for Units 1 and 2 owing primarily to availability of reliable performance and cost information for the MEA technology. The configuration of the retrofitted Keystone station units is similar to the Montour station retrofit, except it assumed that Keystone units are base loaded and that the new carbon capture system was sized to process 100% of flue gas flow rate exiting boilers. In the retrofitted plant, each unit is equipped with a dedicated MEA solvent-based absorption-regeneration system sized to capture 90% of CO₂ in the flue gas stream equivalent to unit maximum continuous rated capacity. Flue gas at the existing FGD units is pre-polished and scrubbed in the MEA absorber, and approximately 90% of the CO_2 in the MEA feed gas is captured. Slip streams of low-pressure steam are extracted from the existing steam turbine LP crossover pipeline and then expanded in a new backpressure turbine to a pressure as required for the MEA solvent regeneration. The backpressure turbine is equipped with a controlled pressure extraction to provide steam at a constant pressure for the MEA reclamation. The existing feedwater system of each unit is modified to recover thermal energy from the CO_2 compression and reduce heat sink load of the retrofitted plant, and the condensate slip stream is directed to compressor inter-stage coolers. The heated condensate from inter-stage coolers is then returned to the feedwater system.

The Keystone retrofit includes a new regeneration system for MEA absorption, including a sulfur polishing unit, a new CO_2 compression and dehydration system including inter-stage water coolers/condensate heaters, a new backpressure steam turbine generator, a new booster fan, and a new MEA makeup and handling system. The scope of modifications to existing systems includes modifications to the flue gas ducts, to the existing high voltage electric system to accommodate operation of a new steam turbine generator, to the existing medium voltage electric system to support operation of the CO_2 capture and compression systems, and to the condensate/feedwater system to recover thermal energy from CO_2 compression and flue gas.

The impact of the Keystone retrofit on plant performance is presented below.

Parameter	Units	Pre Retrofit	Post Retrofit
Gross Power	MWe	900	740
Net Power	MWe	850	589
Auxiliary load	MWe	50	150
Net efficiency HHV	%	36.5%	25.2%
CO ₂ Produced	lb/h	1,809,036	1,809,036
CO ₂ Captured	lb/h	0	1,628,132
CO ₂ Emitted	lb/h	1,809,036	180,904
	lb/MWh		
CO ₂ Specific emissions	net	1,920	307

Retrofit Impact on Keystone Station Unit Performance:

SEWARD

The Seward generating station is located in New Florence, Pennsylvania, 80 miles east of Pittsburgh near Johnstown. It is the largest waste-coal-fired generating plant in the world. Seward was constructed on a 296-acre site of an 82-year-old, coal-fired power plant that was retired at the end of 2003. The new facility, which began commercial operation in late 2004, is comprised of two atmospheric circulating fluidized bed (CFB) boilers firing waste coal and a single steam turbine generator with nominal net rating of 521 MWe.

Oxycombustion technology is assumed for the Seward station carbon capture retrofit based on the Alstom study as presented below.



Oxycombustion Retrofit Block Flow Diagram

A new air separation unit, oxygen heater, gas cooler, flue gas recirculation system, and CO_2 processing system including inter-stage water coolers are all included in the scope of the Seward retrofit. The retrofit also includes modification of the condensate/feedwater system, the boiler draft system, the flue gas ducts, and the existing medium voltage electric system to support operation of the air separation and CO_2 processing systems. The projected impact of the Seward retrofit on plant performance is presented below.

Parameter	Units	Pre Retrofit	Post Retrofit
Gross Power	MWe	572.8	585.3
Net Power	MWe	523.7	391.5
Auxiliary load	MWe	49.1	255.0
Net efficiency HHV	%	35.2%	25.5%
CO ₂ Produced	lb/h	1,005,318	1,009,540
CO ₂ Captured	lb/h	0	945,884
CO_2 Emitted	Lb/h	1,005,318	63,656
	lb/MWh		
CO ₂ Specific emissions	net	1,920	163

Retrofit Impact on Seward Station Unit Performance:

4. CO₂ TRANSPORT ANALYSIS

Summary

Spectra Energy was commissioned by the Clinton Climate Initiative and the Commonwealth of Pennsylvania to undertake a feasibility study to identify the potential for pipeline transportation and temporary storage/collection of CO_2 sourced from various locations in the state of Pennsylvania in a hypothetical central location in Indiana County, PA. Spectra specifically looked at the routing and costs associated with the pipeline infrastructure and the development of an initial hypothetical underground storage facility and/or a centralized collection point.

As part of the Pennsylvania CCS assessment, Spectra Energy completed a study to determine the pipeline facility requirements for transportation of CO_2 into a nearby hypothetical collection point (Jacksonville, PA). Plant locations and requisite flow rates are summarized in the table below.

Location	Flowrate (1000 tons/yr)	Flowrate (MMcfd)
Amostropo	2335	110.0
Amistrong	2555	110.9
Montour	/500	356.3
Seward	3400	161.5
Homer City	10560	501.6
Conemaugh	11000	522.6
Keystone	12250	581.9
US Steel	2800	133.0
Total	49878	2369.4

CO2 Pipeline Cost Estimates

<u>CAPEX</u>	\$1,257m
OPEX o Direct O&M o Benefits o EPC o Insurance	\$2.5m pa 7.6% of direct o&m \$4m pa 0.2% of capex
Total annual OPEX	\$9.2m pa

Total volumes transported (at full scale): 49.88 Mton pa

The costs of transport and storage infrastructure, when expressed per ton of CO_2 stored, are particularly sensitive to volumes of CO_2 transported and stored. A more extensive analysis will be required in the FEED stage in order to confirm these cost levels.

	OD	Length (miles)	Cost (\$ 000,000)
Montour Lateral Armstrong Lateral	20/24/26	48.9/30.3/64.4	753.2
Armstrong to Keystone	16	15.8	70
Keystone to Jacksonville	18	11.9	50.1
Seward Lateral			
Seward to Junction	16	1.6	10.2
Conemaugh to Junction	16	2.8	14.5
Junction to Homer City Homer City to	20	9.4	48.7
Jacksonville	20	6.4	33.1
US Steel Lateral	10.75	32.8	138.4
		Total	1,118.2

The following table outlines the estimated cost for each segment of the pipeline.

Findings

All pipelines, with wall thickness calculated for Gr. 72 pipe, will deliver the CO_2 into the hypothetical Jacksonville collection point at above 1150 psig. Elevation profiles used are based on rough route selections. Uniform pipe heat transfer calculations, based on summer ground conditions, are assumed. No road/water/utility crossings are assumed in any of the elevation profiles. Finally, no pump/compressor station was used in the study. Once the fluid properties are accurately identified (see Appendix), the study should be rerun to ensure that the pipeline is operated within the optimum pressure region.

Pipeline Design

Names	Units	Combine	Glycol	Injection Stream	Water
Vapor Volumetric Flow	ft^3/h	425.66	2.3568	421.29	0.02016
Liquid Volumetric Flow	ft^3/h	425.66	2.3568	421.29	0.02016
Std Vapor Volumetric Flow	MMSCFD	1	0.014181	0.9852*	0.00063194
CO2(Mole Fraction)	%	93.593	0*	95*	0*
N2(Mole Fraction)	%	3.9442	0*	4.0035*	0*
O2(Mole Fraction)	%	0.00098519	0*	0.001*	0*
H2S(Mole Fraction)	%	0.0019704	0*	0.002*	0*
Sulfur(Mole Fraction)	%	0	0*	0*	0*
C1(Mole Fraction)	%	0.97878	0*	0.9935*	0*
H2O(Std Liquid Volumetric Flow)	sgpm	0.0024988	0*	0*	0.0024988*
H2O(Mole Fraction)	%	0.063193	0*	0*	100*
Ethyl Glycol(Std Liquid Volumetric Flow)	sgpm	0.3	0.3*	0*	0*
Ethyl Glycol(Mole Fraction)	%	1.4181	100*	0*	0*

The following table outlines the compositions used for the simulations:

Assumptions & Risks

The study makes the assumption that the CO_2 is supplied at 2150 psig at the source and that compression required at the hypothetical storage location/collection point will be part of the storage site costs. Costs are in 2009 dollars and escalated for 3 years, and the estimate includes 20% contingency and has a range of +40%/-25%. Finally, eminent domain rights were assumed to calculate right of way costs.

There is a major risk that it would be extremely difficult, if not impossible, to site the pipelines without eminent domain rights.



PIPELINE ROUTING MAP: PIPELINE CORRIDOR 1 – MONTOUR LINE





PIPELINE ROUTING MAP: PIPELINE CORRIDOR 3 – TBD NEW PROJECT CONNECTION







PIPELINE ROUTING MAP: PIPELINE CORRIDOR 4 – SEWARD / HOMER CITY LINE

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PIPELINE ROUTING MAP: PIPELINE CORRIDOR 5 - CONEMAUGH LINE



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6. SHORT-TERM CO₂ STORAGE ANALYSIS

This phase of the assessment was conducted to determine the feasibility of developing 1-2 salt caverns for intermediate or temporary storage at a hypothetical location in Indiana County, PA.. For study purposes, it was assumed that two caverns would be created in the bedded salt formations. The following table outlines the proposed leaching rates, water required and brine disposal required.

Target cavern size each usable	1,500,000 bbls
Leached cavern size	2,500,000 bbls
(Assumes 40% insolubles unusable space)	

Cavern 1

Available leaching rate	1,550 gpm
Available leaching rate	53,143 bbls/day
Available leaching days	330 days
Fresh water required	17,537,143 bbls
Brine disposal required	17,537,143 bbls
Cavern space created	2,505,306 bbls
Usable cavern space created	1,503,184 bbls

Cavern 2

Available leaching rate	1,550 gpm
Available leaching rate	53,143 bbls/day
Available leaching days	330 days
Fresh water required	17,537,143 bbls
Brine disposal required	17,537,143 bbls
Cavern space created	2,505,306 bbls
Usable cavern space created	1,503,184 bbls
Total cavern space created	5,010,612 bbls
Total usable cavern space created	03,006,367 bbls

Each cavern would take approximately one year to create and would provide 2.5mm barrels of actual space for CO2 sequestration.

Cost Estimate	Cost	
Compression at Jacksonville	\$8 million	
Cavern Development	\$5.92 million	
Total	\$13.92 million	

Assumptions and Risks:

The study made the assumption that suitable bedded salt was available for the cavern development. It did not include the costs of obtaining land, mineral, or water rights, fresh water supply and brine disposal wells, or monitoring wells and subsidence survey monitoring. All costs are in 2009 dollars escalated for 3 years, and the estimate includes 20% contingency and has a range of +40%/-25%.

Major risks include the possible lack of suitable formations to dispose of the brine downhole, as well as salt stability problems resulting in containment issues due its long term storage in salt. The amount of water required for the debrining of the caverns is significant, and the ability to access this amount of water may be an issue. In addition, due to the nature of bedded salt, the development of large caverns is limited. A number of smaller caverns will need to be created, increasing the costs.
7. POTENTIAL COMMERCIAL CCS MODELS AND FINANCIAL SUPPORT MECHANISMS

Key Regulatory Challenges to Address

Regulatory uncertainty has contributed to the slow pace of CCS deployment. Utilities, independent power producers and developers continue to seek clarity regarding ownership of pore space rights for sequestration. Private sector developers and investors will be reluctant to invest in geologic sequestration opportunities until mechanisms to address liability concerns are developed. Insurance companies have yet to practically underwrite long-term policies for CCS environmental risks as long-range reservoir behavior. A system to address potential CO2 leakage issues is needed to secure the value of carbon reduction.

Monitoring, mitigation, and verification (MMV) protocols must be established for geologic and, if applicable, EOR sequestration. 7 Carbon Sequestration Regional Partnerships supported by DOE are currently in the process of establishing best practices for geologic storage.

Suitable economic incentives must be created in the short-term to encourage development until a carbon price signal emerges. Electricity ratepayers may be unwilling to incur higher initial utility charges for CCS projects that may not offer the lowest-cost compliance option. Current proposals (e.g. bonus allowances, subsidy pools) offer a template for going forward.

Potential Commercial Models

There are several potential value chain structures for a commercial full chain scenario:

Multiple individual supply chains

Each emitting source would correspond to one full-chain CCS company, covering capture, compression, transport and storage of the CO_2 . In the long term, this approach is not compatible with a network approach. However, in the demonstration phase it is possible to envisage starting with an individual supply chain, from which the network could then develop.

Common transport and storage company

Emitters would remain focused on capture and compression. One common company or entity would be responsible for transport and storage. Integrated transport and storage would be more likely to be handled by a regulated entity.

Common full chain company

A common entity would be created to provide integrated Capture, Compression, Transport and Storage of CO2 — this company would be responsible for the full CCS value chain. However, it is questionable whether one company or entity can develop the expertise to provide full-chain service. In addition, the resulting lack of competition would require higher levels of state regulation.

Public Incentives

Monetary or regulatory compensation from the public sector may be necessary to address the increased costs faced by early CCS projects. This public support can take several forms and can be based on several types of criteria. Performance based support is possible, based on each unit of clean output produced. Capital/fixed basis support is another option, given on a per year (e.g. capital grant) basis, and providing refund costs up to a given limit. Regulation is a third option, providing controlled return on investment.

Individual companies will value incentives differently. Specific mechanisms that may be considered include direct loans, loan guarantees, cost sharing (30% with or w/o repay), investment tax credits (e.g. 20%), production tax Credits (e.g. 20% per MWh), accelerated depreciation and availability insurance.

Packages of incentives can address specific risks by themselves or in tandem. Cost sharing and loan guarantees can provide initial capital. Availability insurance can top-up cash flows if the technology underperforms or fails. Finally, production tax credits can support continued CCS operation if the CO_2 price is not sufficient.

PENNSYLVANIA CCS

APPENDIX

APPENDIX A. PENNSYLVANIA CO2 EMISSIONS CONTEXT

Why Pennsylvania?

Electricity Market: Pennsylvania is the third largest electricity generator in the US (219 million MWh) and has the fourth largest generating capacity (45 GW). In a carbon-regulated world, this could translate into a significant financial liability for Pennsylvania, especially as it may be bearing the carbon burden of other states: the Commonwealth's production greatly exceeds its demand, and Pennsylvania exports to other states over one quarter (27%) of the electricity that it generates every year. These exports represent approximately \$5 billion of revenue, equal to 1% of Pennsylvania' Gross State Product (GSP).

Dependence on Coal: Pennsylvania is one of the top coal-consuming states in the nation. Even with massive expansion of renewable energy, the Commonwealth will still remain heavily dependent on coal for the foreseeable future. CCS could be necessary to address the existing fleet and underpin the future of the Commonwealth's coal industry. Coal dominates the Commonwealth's power generation market, typically accounting for approximately 56% of net electricity production in the state.

Pennsylvania is also one of the country's largest producers of coal, ranking fourth in the U.S. in terms of total production and containing 5 of the 40 largest coal mines in the country. In 2006, Pennsylvania produced 66.2 million tons of coal, representing 5.7% of total US production. Pennsylvania also has an estimated 350 million tons of waste coal, with millions of tons more being created every year. Discarded by coal mining operations for decades, waste coal can be used by certain boiler systems and technologies to generate electricity in combination with capture technology. These technologies could unlock the value of the waste coal and offer a low-cost CCS solution.

High Emissions Profile Driven by Coal: Equipping coal-fired plants with CCS will have a significant impact on the Commonwealth's emissions profile and will represent a nationally meaningful reduction. Energy efficiency and renewable generation will simply not be able to achieve the necessary reductions in CO_2 emissions in the requisite time frame.

Pennsylvania produces 280 MMt of CO_2 per year, about 5% of the U.S. total. Pennsylvania's share of emissions exceeds its share of U.S. population by 12%, significantly surpassing the country-wide average on an emissions-per-capita basis. The power generation industry accounts for approximately 40% of the total state emissions, with coal-fired plants responsible for over 90% of that portion. The largest five plants alone produce one fifth of Pennsylvania's overall emissions. The coal mining industry is similarly concentrated, with Consol and Foundation Coal accounting for two thirds of the total production in the state. The top 6 producing mines are also located in south-western Pennsylvania.

Concentrated Emissions Could Enable Network: The largest emitters of CO_2 in Pennsylvania are highly concentrated, both in terms of physical location and in terms of ownership. This concentration of emissions, and thus of liability in a future carbon-regulated environment, provides strong incentives for corporations to involve themselves in a large-scale CCS project. It also offers a platform for the shared infrastructure of a CCS network.

The top 20 highest-emitting plants account for 80% of all power plant emissions in the state, with the top 5 responsible for over half of power industry emissions and one fifth of Pennsylvania's total emissions. The top 4 emitting plants (along with 8 others) are concentrated in the south-western region of the state.

Network Potential: Southwestern Pennsylvania is particularly well-suited for an early user network. Within a 100 mile diameter area, there exist 12 of the 20 largest coal-fired plants, representing 60% of power industry emissions and 25% of the state's total emissions. In addition, 11 of the 20 largest coal mines are in the same area, representing 70% of the state's coal production.

Potential Benefits

There are a number of ways in which Pennsylvania could directly benefit from the early adoption of CCS technology. If Pennsylvania moves early to establish CCS, it may be able to avoid the significant liabilities that a coal-dependent state would otherwise face when new carbon regulations are introduced.

Pennsylvania exports about a quarter of the electricity it produces, resulting in revenues of approximately \$5 billion per year, or roughly 1% of the state economy. This revenue will be at risk following the introduction of carbon regulations, as importing states move to purchase cleaner electricity. If Pennsylvania moves early and pursues a CCS strategy in an integrated and cost-efficient manner, it has the potential to reduce the cost of its electricity in a carbon-regulated world, and therefore make its electricity more competitive for export. Furthermore, technologies that combine the ability to burn low-grade "waste coal" with carbon capture will enable the Commonwealth to turn economic and environmental liability into an incremental source of value and a lost-cost CCS solution.

The creation of an early-user network could result in new jobs and new exportable technologies being created in the Commonwealth. The coal-mining and coal-fired generation industries employ tens of thousands of people and are a significant part of Pennsylvania's economy. A large-scale CCS build-out will help to keep these industries viable in the future. In addition, industry participants in an early user network will benefit from significant intellectual property and commercial know-how.

Finally, Pennsylvania's significant geologic storage capacity represents a new and valuable natural resource for the Commonwealth. If it is fully exploited, Pennsylvania could one day sequester not only its own emissions but the emissions of surrounding states, resulting in a significant financial gain for Pennsylvania.

APPENDIX B. STATUS OF CCS INDUSTRY AND TECHNOLOGY

Introduction

The goal of this section is to provide a literature review and a technical evaluation of various carbon dioxide capture (CC) technologies, with a focus on applicability to carbon capture retrofit of an existing coal fired power plant.

This section will:

- o Discuss the status for each of the carbon capture technologies,
- o Provide technical review and description of known benefits and challenges,
- o Present qualitative screening analysis, and
- \circ Recommend CO₂ capture system for more detailed evaluation for its suitability in the use of carbon capture retrofit at the PA Climate Initiative host sites.

The literature review presented herein is an assessment of proven and unproven developmental technologies that show promise. It is important that this report be read in this context.

CO₂ Capture General Overview

As it applies to fossil fuel fired power plants, CO₂ capture technologies are generally classified into three major categories: post-combustion capture, pre-combustion capture, and oxyfuel combustion.

The figure below illustrates the basic principle of these three capture technology categories.



THREE MAJOR CO₂ CAPTURE TECHNOLOGY CATEGORIES FOR POWER PLANTS

Post-Combustion Capture: In a post-combustion capture system, CO_2 is separated from combustion flue gases and then conditioned and transported to the sites for storage or other uses.

Pre-Combustion Capture: In a pre-combustion capture system, CO_2 is removed prior to combustion. For coal this can be done via gasification. Raw syngas produced in a gasifier is shifted to produce a hydrogen-rich fuel gas mixed with CO_2 . The CO_2 is removed and hydrogen-rich fuel gas is combusted in a gas turbine. Relatively high partial pressure of the CO_2 in the shifted syngas stream makes pre-combustion carbon capture process less energy intensive (as compared to post combustion). A similar scheme can be applied to a natural gas, where water-gas shift step is replaced with steam-methane reforming. Pre-combustion capture technologies are typically utilized for syngas application.

Oxyfuel Combustion Capture: In a pre-combustion capture system, CO_2 is removed prior to combustion. Oxygen combustion technology facilitates carbon capture in two major steps. Step one is accomplished within the oxygen combustion boiler system, in which flue gas with a high CO_2 concentration is produced. Step two includes additional flue gas purification (as dictated by product CO_2 specification), dehumidification and compression. A more detailed description of each of the carbon capture categories is provided in the following sections.

Post-Combustion CO₂ Capture

Post-combustion capture technologies separate CO_2 from combustion flue gases. The combustion flue gases are low pressure streams with CO_2 concentration typically ranging from about 4% (volume) for natural gas fired combined cycle plants to about 14% (volume) for coal fired boilers. Carbon capture from such flue gases presents design challenges, often requiring flue gas preconditioning to reduce its temperature and remove contaminants such as particulates, NOx and SOx. Post combustion streams typically contain 3 to 6 vol.% of O_2 .

Most of the post-combustion CO_2 capture technologies are suitable for a retrofit application of a coal fired power unit. Based on the method of CO_2 removal, the following technologies can be potentially used for the post-combustion CO_2 capture application:

- o Absorption (Chemical/physical solvent scrubbing)
- o Adsorption
- o Cryogenic separation
- o Membranes

Absorption

Chemical Solvent Absorption

Chemical solvent absorption is a chemical reaction that forms a loosely-bonded intermediate compound. Chemical reagents are used to remove the acid gases by a reversible chemical reaction of the acid gases with an aqueous solution of various alkanolamines or alkaline salts in water. For CO_2 capture application, a chemical solvent is exposed to a flue gas where it reacts chemically with CO_2 , separating it from the other gases. The intermediate compound is then isolated and heated, causing it to break down into separate streams of CO_2 and solvent.

Monoethanolamine (MEA) based scrubbing is a commercially available technology. The solvent MEA, a primary amine, reacts with CO_2 at around 100°F and ambient to intermediate pressure, which is suitable for post-combustion flue gas. The process consists of an absorber and regenerator, which are connected by a circulation of the MEA solution. In the absorber, the lean MEA solution contacts with the flue gas stream to remove CO_2 by absorption/ reaction. The CO_2 -rich solution is heated in the regenerator to reverse the reactions and strip the CO_2 gas. The CO_2 lean solution leaves the regenerator. It is cooled and recirculated back to the absorber. At this time, MEA scrubbing technology is a state-of-art option for post-combustion CO_2 capture.

KS® *solvents*: Kansai Electric Power Company (KEPCO) and Mitsubishi Heavy Industries have been developing sterically hindered amines, KS-1, KS-2 and KS-3. Among them, the most well known is KS-1. It is claimed that these amines have the advantage (as compared to MEA) of a lower

circulation rate due to a higher CO_2 loading differential, a lower regeneration temperature, and a lower heat of reaction. KEPCO and MHI reported that the regeneration energy for KS® solvents is much less than that of MEA. They are also non-corrosive to carbon steel at 130°C in the presence of oxygen. KS solvent based absorption systems have been utilized on chemical plants for CO_2 separation. The first commercial plant using KS-1 has been in operation since 1999 at Petronas Fertilizer Kedah Sbn Bhd's fertilizer plant in Malaysia [ⁱ]. Similar commercial systems are also being used by chemical plants in India. The KS solvent based system for coal-fired power plant application is still in the pilot stage. Hokuriku Electric Power Company has operated a test plant with KS® solvents treating 50 m³N/hr of flue gas from a coal-fired unit at the Toyama-Shinko power station.

Chilled ammonia: Developed by Alstom, this process entails scrubbing cooled flue gas with slurry containing dissolved and suspended mix of ammonium carbonate and ammonium bicarbonate in a counter current absorber, similar to SO₂ absorbers. Prior to entering the CO₂ absorber, the flue gas is subcooled in a direct contact cooler recovering large quantities of water. The CO₂-rich slurry from the absorber, containing mainly ammonium bicarbonate, is pumped to a high pressure regenerator, where CO₂ is stripped and separated from other gases. In laboratory tests co-sponsored by Alstom, the Electric Power Research Institute (EPRI), and others, the process has demonstrated a potential for capturing more than 90% CO₂ at an efficiency penalty that is much lower than that of other CO₂ capture technologies. The challenges are ammonia to capture CO₂ from a 1.7 MW equivalent slip stream from flue gas of a coal-fired boiler was launched by Alstom and EPRI at the We Energies' Pleasant Prairie Power Plant in Wisconsin. The chilled Ammonia system is not currently offered commercially. Alstom is targeting its full commercial release by 2015, with the possibility of executing some selected commercial projects in 2011 and 2012.

Aqueous Ammonia: This joint NETL-Powerspan development entails reacting ammonia with CO_2 in the flue gas to form ammonium carbonate, and subsequently heating the ammonium carbonate to release a pure CO_2 stream. Advantages include: (1) low theoretical heat of regeneration; and (2) multi-pollutant control with saleable by-products (ammonium sulfate and ammonium nitrate fertilizers) using Powerspan's commercial ECO^{TM} system. One technical challenge is the degradation of carbonate in the CO_2 absorber leading potentially to ammonia slip in the flue gas. Powerspan ECO_2^{TM} technology is still at the pilot stage. An ECO_2^{TM} pilot unit has been installed at the First Energy Burger Plant and started operation in October 2008. It processes 1 MWe equivalent slip stream to capture 20 TPD of CO_2 .

Two ECO_2^{TM} demonstration projects have been announced by Powerspan. In November 2007, NRG Energy, Inc. and Powerspan announced their intention to commercially demonstrate the ECO_2^{TM} process at NRG's WA Parish plant in Texas. The ECO_2 demonstration facility will be designed to capture 90 percent of 125 MWe slip stream, and the captured CO_2 (about one million tons of CO_2 annually) is expected to be used for enhanced oil recovery in the Houston area. The Parish plant is expected to be online in 2012.

In June of 2008 Powerspan and Basin Electric Cooperative announced a partnership to commercially demonstrate CO_2 capture technology for conventional coal-based power plants. The demonstration project would capture about one million tons per year of CO_2 from a slip stream of the exhaust from Unit 1 at the Basin Electric Antelope Valley Station. The Powerspan technology would remove CO_2 from the equivalent of a 120 MWe slipstream. The captured carbon dioxide would then be fed into an existing CO_2 compression and pipeline system owned by Basin Electric's Dakota Gasification Company. Start of construction of the CO_2 capture system is scheduled for 2009, with operation commencing in 2012.

Dry Regenerable Carbonate Sorbent Adsorption

In this process, the sorbent material (based on sodium carbonate) captures CO_2 at a boiler with typical flue gas exhaust pressure and a temperature of approximately 60°C (carbonation). The sorbent is then regenerated at a temperature of about 120°C to yield a concentrated stream of CO_2 for sequestration or other use. The regenerated sorbent is recycled to the adsorption step for CO_2 capture. The process is expected to be less expensive and energy intensive than MEA technologies. This process is compatible with current power plant operating conditions and hence applicable for CO_2 capture from coal and natural gas-fired power plants. The challenges for the technology include continuous circulation of large quantities of solids and requirements for contaminants. The developer of the technology is the Research Triangle Institute. Currently, the technology is in the small-scale technology demonstration phase, in which a 1 ton/day CO_2 capture facility is being built. The demonstration of the small-scale pilot is scheduled for 2010, and a large-scale demonstration at a UNC Chapel Hill coal-fired plant is planned for 2012 (100 tones of CO_2 captured per day). It is envisioned that the technology will be ready for commercial offering in 2015.

Cryogenic Separation

 CO_2 can be separated from other gases by cryogenic distillation. For CO_2 capture application cryogenic separation process requires pressures above 300 psia at temperatures at about minus 55°C. Cryogenic separation is used commercially for purification of CO_2 from streams that already have high CO_2 concentrations (typically >80%). It is not normally used for more dilute CO_2 streams, although it has recently been claimed that CO_2 can be captured (by freezing it as a solid) from atmospheric pressure flue gases with energy losses similar to those of other techniques. A major disadvantage of cryogenic separation of CO_2 is the amount of energy required to provide the refrigeration necessary for the process, particularly for dilute gas streams. Another disadvantage is that some components, such as water, have to be removed before the gas stream is cooled. Cryogenic separation has an advantage of enabling direct production of liquid CO_2 , which makes its transport easier. The most promising applications for cryogenics are expected to be for separation of CO_2 from high pressure gases, such as in pre-combustion capture processes, or Oxyfuel combustion in which the input gas contains a high concentration of CO_2 .

Gas Separation Membranes

Gas separation membranes rely on differences in physical or chemical interactions between gases and a membrane material, causing one component to pass through the membrane faster than another. Various types of membranes are currently available, including porous inorganic membranes, palladium membranes, polymeric membranes and zeolites. Membranes cannot usually achieve high degrees of separation, so multiple stages and/or recycle of one of the streams is necessary. This leads to increased complexity, energy consumption and costs. Several membranes with different characteristics may be required to separate high-purity CO_2 . Membranes could be used to separate CO_2 at various locations in power generation processes, for example from fuel gas in IGCC.

Gas absorption membranes are micro-porous solids that are used as contacting devices between a gas and a liquid. The CO_2 diffuses through the membrane and is removed by an absorption liquid such as amine, which selectively removes certain components. In contrast to gas separation membranes, it is the absorption liquid, not the membrane that gives the process its selectivity.

Efforts are underway to develop membranes used for post-combustion CO₂ capture. For example, Membrane Technology and Research (MTR) is in the process of testing technology for postcombustion flue gas applications. The demonstration of a small-scale pilot is scheduled for 2009 at Arizona Public Services' (APS) natural gas combined cycle Red Hawk plant, and for 2010 at APS' Cholla coal-fired power plant [ⁱⁱ]. Overall, membrane technologies for post-combustion CO₂ capture are still in an early stage of development.

Pre-Combustion CO₂ Capture

In general, pre-combustion CO_2 capture technologies favor high pressure and low temperature, and are not suitable for working in an oxidizing atmosphere. Hence, pre-combustion CO_2 capture technologies are not suitable for retrofit application of a pulverized coal-fired unit. This is further explained in the following sections.

Chemical Solvent Absorption

In a chemical absorption process, the acid gases react to an intermediate liquid solvent species and are removed from the bottom of the absorber column with the rich solvent.

Diethanolamine (DEA) is a secondary amine. Like MEA, it can absorb CO_2 . However, it is less reactive than MEA and is highly susceptible to oxygen degradation [ⁱⁱⁱ], which precludes DEA utilization for post-combustion CO_2 capture application.

Methyldiethanolamine (MDEA) is a tertiary amine. In recent years, MDEA has acquired a much larger share of the gas-treating market. Compared with primary and secondary amines, MDEA has superior capabilities for selectively removing H₂S in the presence of CO₂. MDEA is resistant to

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degradation by organic sulfur compounds, has a low tendency for corrosion. Compared to MEA it requires a relatively low circulation rate, and consumes less energy. Several MDEA-based solvents formulated for high H₂S selectivity are commercially available. However, MDEA is not suitable for post-combustion applications due to its oxygen-caused degradation [^{iv}]. MDEA has been used for H₂S removal in chemical plants and IGCCs.

The majority of chemical solvents are organics amine based. However, there are some alternative inorganic solvent systems such as Na/K carbonates.

Benfield process uses an inorganic chemical solvent potassium carbonate and catalysts. The process typically works at $160/250^{\circ}$ F and 320/1000 psia. Benfield process is widely used for purification of H₂ streams, and is not considered a good option for post-combustion CO₂ capture due to low pressure of the flue gas. This process is commercially available.

Physical Solvent Absorption

Physical solvent scrubbing of CO_2 is a well established technology, which is widely utilized to treat both natural and synthesis gas streams. In a physical absorption process the acid gases are physically absorbed into the liquid solvent and are removed from the bottom of the absorber column with the rich solvent. The solubility of individual gas compounds in a physical solvent follows Henry's law, and favors high pressure and low temperature operation. Physical solvents combine less strongly with CO_2 than do chemical solvents. The advantage of such solvents is that CO_2 can be separated from them in the stripper mainly by reducing the pressure, resulting in much lower energy consumption. These solvents are better suited for applications at a higher pressure such as syngas streams in coal-based IGCC process (typically 20 bar) or higher and the concentrations of CO_2 are about 35 - 40 %, and hence the CO_2 partial pressure is much higher than that in combustion flue gas. The following are some commercially available physical solvents that could be used for CO_2 capture in some applications such as IGCC.

The *Rectisol process* uses chilled methane as a scrubbing solvent. Typically, the process works at temperatures 14/-94 °F and higher than 290 pisa. The *Selexol process* uses dimthylether of polyethylene glycol as the solvent. Typical work condition is -4/104 °F and 290/435 psia. The *Fluor process* uses propylene carbonate as the solvent. The solvent generally works below ambient temperature and high pressure (450-1000psia). Finally, the *Purisol process* uses n-methyl-2-pyrolidone as the solvent. The process condition generally works at temperature of -4/104 °F and high pressure (\geq 290 psia).

Commercially available physical solvent scrubbing technologies generally require high pressure and low temperature, and hence are not considered preferable options for post-combustion CO_2 capture processes. However, some efforts are being made to develop new solvents, such as ionic liquids, that are expected to be suitable for post-combustion CO_2 capture.

These *Ionic liquids* (ILs) are organic salts with low melting points, many below room temperature. Even though they are liquids, they have negligible vapor pressure. Thus, they have an advantage over conventional solvents for absorption of CO_2 from flue gas because they do not contaminate the purified gas stream. Typical ILs are composed of imidazolium, pyridinium, ammonium or phosphonium cation with any of a wide variety of anions. Their properties can be varied tremendously by the choice of anion, cation and substituents. Ionic liquids are typically combines with supported membranes in the CO_2 capture application. This technology is still in laboratory stage and is being developed by the University of Notre Dame, Sachem Inc., and Merck.

Mixed Physical/Chemical Solvents Absorption

There are some commercially available scrubbing technologies that use a mixture of physical and chemical solvents. The *Sulfinol process* was developed by Shell. The solvent is a mixture of DIPA and Sulfolane (tetrahydrothiophene dioxide). The former provides a chemical solvent and the latter a physical solvent. Meanwhile a modified solvent, known as Sulfinol-M, has been developed that uses MDEA as the chemical solvent. The Sulfinol process typically works at a pressure higher than 73 psia and can be used in applications such as IGCC.

The *Amisol process* was developed by Lurgi Germany. The process uses a mixture of MEA or DEA with methanol. The process works at ambient temperature and a pressure higher than 145 psia. The process has been applied downstream of a number of oil gasification units, but has not established a wide market.

Pressure/Temperature/Electric Swing Adsorption

Some solid materials with high surface areas, such as zeolites and activated carbon, can adsorb CO_2 and be used to separate CO_2 from gas mixtures by adsorption. The process operates on a repeated cycle with the basic steps being adsorption and regeneration. In the adsorption step, gas is fed to a bed of solids that adsorbs CO_2 and allows the other gases to pass through. When a bed becomes fully loaded with CO_2 , the feed gas is switched to another clean adsorption bed and the fully loaded bed is regenerated to remove the CO_2 . In pressure swing adsorption (PSA), the adsorbent is regenerated by reducing pressure. In temperature swing adsorption (TSA), the adsorbent is place by passing a low-voltage electric current through the adsorbent.

PSA and TSA have been employed commercially for CO_2 removal from synthesis gas for hydrogen production. ESA is not yet commercially available, but it is said to offer the prospect of lower energy consumption than the other processes. Adsorption is not yet considered attractive for large-scale CO_2 removal from combustion flue gas because the capacity and CO_2 selectivity of available adsorbents is low. However, it may be successful in combination with another capture technology. Some efforts are being undertaken to develop adsorbents that can operate at higher temperatures in the presence of steam with increased capacity and improved selectivity, e.g. dry regenerable carbonate sorbent.

Oxy-Combustion CO2 Capture

The oxygen combustion CO_2 removal process for coal-fired boilers is a developing technology. This technology remains unproven at commercial scale in power generation applications. The first oxygen-fired PC pilot unit is a 30 MWth Alstom unit that began operation in summer of 2008 at the Schwarze Pumpe site in Germany. Engineering for the 300 MWe oxyfuel demonstration plant is planned for 2010 and demonstration plant operation is projected for 2015.

Oxygen combustion technology facilitates carbon capture in two major steps. Step one is accomplished within the oxygen combustion boiler system, in which flue gas with a high CO_2 concentration is produced. Step two processes include additional flue gas purification (as dictated by product CO_2 specification), dehumidification and compression. The flue gas purification step typically employs low temperature distillation to separate carbon dioxide from the inert gases such as nitrogen and oxygen.

The *cryogenic distillation* process is utilized by commercially available air separation units (ASU) to produce oxygen for combustion process. A major disadvantage of cryogenic ASU is the amount of energy required to provide the refrigeration necessary for the separation process. Several advanced concepts are being developed to reduce ASU parasitic load. Those include ion transfer membranes being developed by Air Products and oxygen transfer membranes being developed by Praxair. As part of the on-going project, in 2006 Air Products designed and commissioned in 2006 a 5 tpd prototype facility to test multiple membrane modules under commercially relevant operating conditions. A larger 150 tpd facility is expected to begin commissioning in late 2010. Overall, membrane technologies for oxygen separation are still in an early stage of development.

Alstom is in the early stages of developing limestone-based *chemical looping system* for existing and new pulverized coal-fired power plants. In a sense, Alstom chemical looping process is oxycombustion without oxygen plant. The system operates as follows: a solid limestone-based oxygen carrier circulates between the oxidizer and the reducer and carries oxygen, heat, and fuel energy. The carrier picks up oxygen in the oxidizer, and leaves nitrogen behind. The carrier delivers oxygen to the fuel in the reducer. Heat generated by fuel oxidation in the reducer produces steam for power.

Other Technologies

There are a few technologies in development that do not fit into the categories above. The *Enzymatic* CO_2 capture process, developed by Carbonzyme Inc., uses an enzyme-catalyzed Carbonic Anhydrase based liquid membrane biomimetic reactor. It is claimed that the technology is applicable to treating

a large number of different flue gas streams, e.g., flue gases generated by combusting fuels such as natural gas, oil or various ranks of coal. The process operates at moderate temperature and pressure. It has the ability to separate CO_2 from other gases while using modest energy and employing no hazardous chemicals. However, the technology is still in the early development stages.

TECHNOLOGY SELECTION FOR CO₂ CAPTURE RETROFIT APPLICATION

This section provides carbon capture technology assessment identifying relative technical and economic merits of various carbon capture options and available technologies for applications at the PA Climate Initiative host generators.

Preliminary Screening of Available Technologies

Preliminary screening of the CO₂ capture technologies is based on the following criteria:

- o Must be suitable for retrofit application of a coal fired unit, and
- o Must be commercially available or at least in pilot/demonstration development phase.

The table below presents a summary of CO_2 capture technologies discussed in the previous sections, and their compliance with specified selection criteria. CO_2 capture technologies that met specified criteria are selected for further evaluation in this report. Those technology options that are grayed out in the table are either considered not to be suitable for CO_2 capture retrofit application or have not met commercial status criterion.

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CO₂ Capture Technology Summary:

	MEA	Chilled Ammonia	KS Solvents	Aqueous Ammonia	Oxy - combustion	DEA	Benfield	Rectisol
Technology type	Chemical solvent	Chemical solvent	Chemical solvent	Chemical solvent	"Cryogenic" Distillation	Chemical solvent	Chemical solvent	Physical solvent
Applicability for CO ₂ retrofit	Ycs	Yes	Yes	Yes	Yes	No	No	No
Commercial status	Commercial	Pilot	P_{ilot} (a)	Pilot	Pilot	Commercial	Commercial	Commercial

	MEA	Chilled Ammonia	KS Solvents	Aqueous Ammonia	Oxy - combustion	DEA	Benfield	Rectisol
Technology type	Chemical solvent	Chemical solvent	Chemical solvent	Chemical solvent	"Cryogenic" Distillation	Chemical solvent	Chemical solvent	Physical solvent
Applicability for CO ₂ retrofit	Yes	Yes	Yes	Yes	Yes	No	No	No
Commercial status	Commercial	Pilot	Pilot ^(a)	Pilot	Pilot	Commercial	Commercial	Commercial

	Cryogenic	Ionic Liquids	Dry Regenerable Carbonate Sorbent	Amine Enhanced Sorbents	Membrane ^(b)	Carbozyme Technology
Technology type	Cryogenic	Physical solvent	Physical sorbent	Chemical sorbent	Membrane	Membrane / Absorption
Applicability for CO ₂ retrofit	As a part of Oxycombustion	Yes	Yes	Yes	No	Yes
Commercial status	Commercial	Lab scale	Pre-pilot	Lab scale	Commercial	Lab scale

Notes:

(a) KS-1 scrubbing technology is commercially available for chemical plants, and is in pilot stage for coal fired applications. Membrane CO₂ separation technology for post-combustion applications is still in its early development stage.

Comparison of Selected CO2 Capture Technologies

Based on preliminary screening, MEA scrubbing technology, Chilled Ammonia scrubbing, KS solvents scrubbing, Aqueous Ammonia scrubbing, and Oxycombustion have been selected for further evaluation. This section provides a more in-depth description, applicability, and comparison of the pre-selected technologies.

MEA Scrubbing

Amine scrubbing technology has been established in the chemical and oil industries for over 60 years. It is usually used for the removal of hydrogen sulfide and CO_2 from natural gas streams and/or from chemically reducing (primarily oxygen deficient) gases. However, there are several facilities in which Monoethanolamine (MEA), a primary amine, is used to capture CO_2 from flue gas streams.

Currently, MEA is the most common solvent used for removing CO_2 from low pressure flue gas. A general process diagram for MEA scrubbing is depicted in the figure below. The fundamental underlying principle is the exothermic, reversible reaction between a weak acid (e.g., CO_2) and a weak base (e.g., MEA) to form a soluble salt. The inlet gas is contacted counter-currently with 'lean' solvent in the Absorber. The acid gases are preferentially absorbed by the solution. The solution, 'enriched' with CO_2 , is pre-heated before entering the Stripper where, through the addition of heat, the reaction is reversed. From the bottom of the column, the lean solvent exchanges heat with the rich solvent entering the column, and is recycled back to the Absorber. From the top, a high-purity (dry-basis) CO_2 is produced. This general process is also applicable to other amine scrubbing or ammonia-based scrubbing.

MEA also reacts with the other acid gases present in the flue gas, such as SO_2 and NO_2 , forming heat stable salts (HSS). HSS have to be removed from the process, and lost solvent must be replaced with make-up amine. To limit operating costs, it is typically recommended that the flue gas entering the MEA absorber should be pre-treated to lower its SO_2 and NO_2 content to below 10 ppmv. Nitrogen oxide (NO) does not react with amines. An additional benefit of the MEA CO_2 capture process is that the flue gas discharged to the atmosphere contains no SO_2 .

MEA is considered a state-of-the-art process for post-combustion CO_2 capture [v]. It has been reported that CO_2 recovery rates of 98% can be achieved, although around 90% capture is typically specified for power plant applications, and product CO_2 purity can be in excess of 99%. Major concerns with MEA and other amine solvents include equipment corrosion in the presence of O_2 and other impurities, relatively high solvent degradation rates due to solvent reactions with SO_2 and NO_2 , and high thermal energy demand for solvent regeneration (1500-1700 Btu/lb of CO_2).

These factors generally contribute to large equipment sizes, high solvent consumption and significant energy losses. New or improved solvents with higher CO_2 absorption capacities, faster CO_2

absorption rates, higher degradation resistance, lower corrosiveness and energy use for regeneration are being researched and developed to reduce equipment sizes and capital and operating costs.



MEA BASED CO₂ CAPTURE PROCESS

Source [vi]

The table below provides a summary of selected CO_2 capture plants that are in commercial operation. These plants are typically much smaller than electric-utility-scale. However, it has been reported [vii] that commercial CO_2 MEA absorption plants are available with the capability of processing flue gases equivalent to a 400 MWe coal-fired power unit.

Operator	Location	Capacity (tons/day CO ₂)	Fuel Sources	CO ₂ Use	Technology	Status
IMC Global	Trona, CA	800	Coal Boiler	Carbonation of brine (soda ash)	Kerr-McGee MEA	Operational since 1978
Mitchell Energy	Bridgeport, TX	493	Gas heaters, engines, turbine	EOR	Inhibited MEA	Operational since 1991
Northeast Energy Associates	Bellingham, MA	320	Gas turbines	PURPA (food-grade)	Fluor Daniel	Operational since 1991
Applied Energy Systems	Poteau, OK	200	Coal boiler (fluidized bed)	PURPA (food-grade)	Kerr-McGee MEA	Operational since 1991
Sumitomo Chemicals	Chiba, Japan	165	Gas boilers plus oil/coal boiler	Food-grade	Fluor Daniel	Operational 1994
Luzhou Natural Gas	China	160	NH3 plant reformer exhaust	Urea	Fluor Daniel	Operational since 1998
Indo Gulf Fertilizer Co.	India	150	NH3 plant reformer exhaust	Urea	Dow MEA	Operational since 1988
Prosint	Rio de Janeiro, Brazil	90	Gas boiler	Food-grade	Fluor Daniel	Operational since 1997
Liquid air Australia	Australia	2 x 60	Gas boiler	Food-grade	Dow MEA	Operational since 1985
AES, Shady Point Power Station	Panama, OK	190	Coal fired CFB boiler	Food-grade	ABB Lummus	Operational since 1991
AES, Warrior Run Power Station	Cumberland, MA	150	Coal fired CFB boiler	Food-grade	ABB Lummus	Operational since 1999

Commercial MEA-Based CO₂ Plants:

Source [vii]

There are several commercial providers of MEA technology, including Fluor Daniel (Econamine process), CB&I Lummus Global (Kerr-McGee process) and Dow MEA. Different technologies may use proprietary oxidization inhibiters and MEA solutions of different concentrations. Fluor Daniel Econamine FGSM, for example, uses 30% MEA solution incorporating additives to control

corrosion and degradation (both oxidative and thermal). Currently there are more than 20 commercial plants using Econamine FGSM ranging in size from 5 to 400 tons CO_2 /day. CB&I Lummus Global technology uses 15%–20% MEA solution. There are currently four commercial plants ranging in size from 150 to 800 tons of CO_2 /day that capture CO_2 from a coal-fired plant flue gas stream. Different technologies may require different solvent regeneration energies. Fluor claims that Econamine FG Plus requires both a lower circulation rate and a lower reboiler duty than Kerr-McGee MEA due to the solvent properties [viii].

KS Solvent Scrubbing

Since 1990 the Kansai Electric Power Co., Inc (KEPCO) and Mitsubishi Heavy Industries, Ltd. (MHI) have been developing proprietary Kansai-Mitsubishi carbon dioxide recovery process to recover CO2 from thermal power plant flue gases. The process shown in the figure below uses solvent KS-1, a hindered amine. The developer, MHI, claims that the KS-S solvent has the advantages of high CO₂ loading, negligible corrosion, negligible solvent degradation, low utility and solvent consumption, easy operation and maintenance, and low operating costs [ix].



KS SOLVENT BASED CO₂ CAPTURE PROCESS

KS-1 has a lower circulation rate than MEA because of KS-1's higher lean to a rich CO_2 loading differential, lower regenerative temperature (248°F), and lower heat of reaction with CO_2 .

The first commercial CO_2 plant to use this technology is installed at an ammonia facility in Kedah Darul Aman, Malaysia. CO_2 is recovered from the flue gas of the steam reformer of the ammonia plant and delivered to the CO_2 compressor for urea synthesis. Recovered CO_2 is then used to increase urea production. The CO_2 recovery capacity is 160T/D (200T/D Max). The plant has been operating since October 1999.

Indian Farmers Fertilizer Co. also installed two units to recover CO_2 from steam reformer flue gases. CO_2 is compressed and then used for urea synthesis. The two units were started in December 2006. Two similar units using KS-1 scrubbing technology are planned to be installed at chemical plants in Abu Dhabi and China.

MHI is testing KS technology for coal-fired power plant application. A pilot plant designed to capture 10 tons of CO_2 per day from a coal-fired boiler flue gas has been constructed at J-POWER 2 x 500 MWe Matsushima Power Station, Nagasaki, Japan. The pilot unit was installed in July of 2006, and has demonstrated more than 5000 hours of continuous operation [x]. MHI has reported a relatively low achieved regeneration energy requirement for KS solvents (as compared to MEA) of 1,314 Btu/lb (730 kcal/kg) to 1476 Btu/lb (820 kcal/kg). MHI predicts that a further 15% decrease in heat consumption could be accomplished via improvement of the regeneration process and/or integration with power plant systems. MHI has also reported that the flue gas at the pilot unit was pre-treated before entering the absorber to limit SO₂ concentration in the flue gas to 0.1 ppm, which is a significantly more stringent requirement than the MEA limit of 10 ppmv. [xi].

Chilled Ammonia Scrubbing

The chilled ammonia scrubbing process (CAP), similar to amine scrubbing, utilizes the simple chemistry of the NH_3 - CO_2 - H_2O system and the ability of an ammoniated solution to absorb CO_2 at low temperature, and to release the CO2 at moderately elevated temperature and high pressure. Low temperature and relatively low NH3/ CO2 mole ratios (<2.0) are maintained to minimize ammonia vapor pressure in the absorber.

The ammonia-based process for CO_2 capture has many advantages over the current post-combustion CO_2 capture technologies. It features high CO_2 loading with and without slurry in the absorber (as high as 150-200 grams of CO_2 per Kg of slurry), relatively low rate of cooling requirements corresponding to low heat input, and high pressure regeneration using thermal energy to generate a high-pressure CO_2 stream. Regeneration pressure may be as high as 30 Bar at moderate 120°C regeneration temperature, although even higher regeneration pressure is conceivable. It also features low heat of reaction and heat requirements for regeneration, with a heat of regeneration 30 percent lower than that of KS-1 [xii]. In addition, the ammonia reagent is both relatively cheap as well as stable under the operating conditions of the process. Challenges for the chilled ammonia process include ammonia volatility and poor kinetics in the absorber.

The chilled ammonia process (CAP) is being developed by Alstom. The company is now engaged in an extensive development and commercialization program, with the objective of offering a fully commercial product by 2015. The process has the potential to be applied to capture CO_2 from coal-fired boilers' flue gases and natural gas combined-cycle (NGCC) systems.

The technology is currently being tested in a field pilot plant that has been constructed at the We Energies' Pleasant Prairie power plant in Wisconsin, USA. Alstom has designed, constructed and is operating a system that captures CO_2 from the equivalent of a 1.7 MWe flue gas slipstream from a coal-fired boiler. The project is designed to capture up to 15,000 tons of CO_2 /year. Testing will continue through 2008. Key objectives of the pilot project involved creating proof of concept, conducting long-term tests to establish process integrity, measuring energy consumption, and developing a techno-economic analysis to scale the system for commercial applications [xiii].



SCHEMATIC OF CHILLED AMMONIA CO2 CAPTURE SYSTEM PROCESS

According to a 2008 MHA study [xiv], the CAP-based system has a significant advantage over an MEA-based system in overall plant efficiency (~5-6%) (See table below). Performances of CAP and

MEA systems in study [xiv] are compared based on a supercritical pulverized coal nominal 460 MWe unit application.

	Supercritical PC without CO ₂ Removal	Supercritical PC with MEA CO ₂ Removal	Supercritical PC with NH3 CO ₂ Removal
Coal Feed rate, lb/h	333,542	333,542	333,542
CO ₂ captured at 90% eff. Lb/h	700,000	700,000	700,000
Coal heating value, Btu/lb (HHV)	11,666	11,666	11,666
Boiler heat input, MMBtu	3,981	3,981	3,981
LP STEAM EXTRACTION LB/H	0	1,215,641	270,000 - 500,000
Power loss, kWe	0	90,230	20,000 - 37,000
GROSS POWER, KWE			
Steam turbine power	498,319	408,089	478,319 - 461,319
Generator loss	7,211	5,835	7,018 - 6,676
Gross plant	491,108	402,254	471,301 - 454,643
AUXILIARY LOAD, KWE			
Induced draft fan	5.050	19,880	10,000
FGD pumps and agitators	3,450	3,450	3,450
Boiler feed water booster pumps	2,670	3,090	2,670
Circulating water pumps	3,540	1,950	2,500
Cooling tower fans	2,030	1,110	2,030
Pumping CO ₂ system	0	1,940	5,000
Chillers	0	0	8,900
CO ₂ compressor	0	29,730	9,500
Balance of plant	12,310	11,580	12,000
Total auxiliary power	29,050	72,730	56,050
NET POWER OUTPUT	462,058	329,524	415,251 – 398,593
Net efficiency, % HHV	40.5	28.9	36.4 - 35.0
Net heat rate, Btu/kWh, HHV	8,421	11,808	9,370 - 9,762

Comparison between Chilled Ammonia and MEA System:

Source: [xiv]

Aqueous Ammonia Scrubbing

The aqueous ammonia CO_2 scrubbing process is being developed by Powerspan Corporation. The advantages of the aqueous ammonia CO_2 scrubbing process are similar to those of CAP scrubbing. First, aqueous ammonia is less expensive than amines (0.30/lb CO_2 carrying capacity versus 3.8/lb CO_2), which should lower solvent make-up costs. Second, aqueous ammonia has a lower heat of reaction for regenerating the chemical solvent (262 Btu/lb CO_2 captured versus 825 Btu/lb for mono-ethanol amine) [xv]. Hence, the aqueous ammonia process uses less steam for solvent regeneration as compared to amine scrubbing technologies. Capital costs for the aqueous ammonia process are expected to be lower, partially due to the cascading effect of improved efficiency.

The $ECO_2^{TM} CO_2$ removal process is integrated with Powerspan's electro catalytic oxidation (ECO) process, which controls NO_x , SO_x , and particulate emissions. Thus, integration with aqueous ammonia CO_2 capture offers lower net cost for SO_2 , NO_x , and mercury control that benefits the economics of a multi-pollutant system [v]. Finally, Ammonium sulfate, which is produced as a byproduct of the Powerspan process, can be utilized as a raw material for fertilizer production.

The figure below shows process diagram of the Powerspan aqueous ammonia multi-pollutant capture system. The flue gas is contacted with aqueous ammonia to form ammonia nitrate, ammonia sulfate, and non-gaseous mercury specie. The solution is then passed through an activated carbon bed for mercury removal before passing to a crystallizer and granulator for solid fertilizer production. CO_2 is removed from the flue gas in an ammonia scrubber, and then compressed for transportation and other applications.

The Powerspan ECO_2^{TM} process accomplishes management of ammonia vapor release to treated flue gas by recycling low PH liquor from the upper loop of the ECO SO_x absorber into the upper ammonia capture section of the ECO_2 absorber. Thus, the Powerspan process requires significant SO_2 concentrations at the inlet of the ECO SO_2 absorber to control the ammonia vapor emissions from the integrated process. Powerspan's CO_2 capture system becomes more expensive with a lower SO_2 concentration in the feed gas.

SCHEMATIC OF AN AQUEOUS AMMONIA CO2 CAPTURE SYSTEM PROCESS



Integrated ECO[®]-ECO₂ Process Flow

The Powerspan ammonia-based ECO system that captures NOx and SOx from the flue gas has been demonstrated at commercial scale. A three-year pilot-scale testing program of the "ECO2" CO2 capture technology was launched in October, 2008 at the FirstEnergy's R.E. Burger Plant. The ECO₂ pilot will process approximately 1-megawatt equivalent slipstream (20 TPD of CO₂) drawn from the outlet of the 50-MW Burger Plant ECO commercial unit. It will be designed to capture 90 percent of incoming CO_2 (approximately 20 tons of CO_2 per day). In June of 2008, Powerspan and Basin Electric announced a partnership to commercially demonstrate CO2 capture technology for conventional coal-based power plants. The demonstration project would capture about one million tons per year of CO2 from a portion of the exhaust from Unit 1 at the Basin Electric Antelope Valley Station. The Powerspan technology would remove CO₂ from the equivalent of a 120 MWe slipstream. The captured carbon dioxide would then be fed into an existing CO₂ compression and pipeline system owned by Basin Electric's Dakota Gasification Company (DGC). The start of construction of the CO_2 capture system is scheduled for 2009, with operation commencing in 2012. The predicted performance of a power plant equipped with an aqueous ammonia system (see table below) shows its notable advantage over MEA based system in overall plant efficiency ($\sim 5\%$).

	Case	1	2	3	4	5	6
Sorbent		None	MEA	Aa	АА	$(USC)^1$	AA (USC) ¹
Compone	ent(s) Removed	None	CO ₂	CO ₂	CO_2SO_X NO_XHg	CO_2	CO _{2,} SO _x NO _x Hg
Total Gro (MWe)	oss Power	425	492	478	482	473	476
-	Base Plant	22.1	28.3	27.3	27.5	25.1	25.3
Dad	CO ₂ Capture	-	21.4	14.5	10.3	13.6	10.2
ary Lo IWe)	CO ₂ Compression	-	35.3	30.0	30.2	28.1	28.3
ŭ li S	NO_x and SO_x	3.1	4.4	3.8	11.0^{2}	3.5	10.3^2
Aux	Transport and Storage	-	2.9	2.5	2.5	2.3	2.3
Total		25	92	78	82	73	76
Net Power		400	400	400	400	400	400
Coal Flow	vrate (ton/day)	3,4800	4,895	4,172	4,200	3,904	3,935
CO ₂ Capt	ured (ton/day)	-	10,240	8,727	8,789	8,168	8,233
Net Heat HHV)	Rate (Btu/kWh,	8,453	11,896	10,139	10,211	9,489	9,565
Fertilizer (ton/day)	production	-	-	-	433	-	415
Efficiency	7	40%	29%	34%	34%	36%	36%
Energy Pe	enalty	-	29%	17%	17%	16%	16% ¹
Energy Per ¹ Ultra-supe	nalty: Percent decre ercritical steam cycl	ase in power e; USC bease	plant efficienc case no-captu	ty due to CO_2 re is 43% efficiency of the first state of the first	capture cient		•

Aqueous Ammonia and MEA Systems Comparative Performance:

²Auxiliary load for the multi-pollutant removal ECO is ~11MW

Source [xv]

Oxycombustion

Oxycombustion for power generation is an emerging technology, which currently is at the threshold between pilot-scale testing and the first full-scale demonstration plants. A lot of research work has already been done on this subject and there is common agreement on its general feasibility, although not all issues are yet fully understood. Testing has been done on a lab scale and in pilot-scale facilities up to 3 MWth. So far no major technical barriers have been identified that would prevent the application of the technology in a large scale. The first 30 MWth pilot demonstration plant has been in operation since summer of 2008.

The objective of oxygen-fired combustion is to combust coal in an enriched oxygen environment by using pure oxygen diluted with recycled flue gas. In this manner, the flue gas is composed of primarily CO_2 and H_2O , so that a concentrated stream of CO_2 is produced by condensing the water in the exhaust stream.

Operation of an oxygen-fired boiler with gas recirculation (see figure below) is essentially the same as an air-fired boiler with the exception that recycled flue gas replaces the primary and secondary air streams. The oxygen is injected into primary and secondary streams downstream of the airheater. All oxy-fired system equipment is essentially the same as in an air-fired system except for the gas cooler for condensing water from the gas to be recycled. Since the flue gas is recycled and only high-purity oxygen is introduced, the flue gas throughout the system contains a much higher level of CO_2 and very little nitrogen. This increases emissivity, which is essentially offset, in regard to heat transfer, by the change in density and resulting gas velocity.



SCHEMATIC OF OXYCOMBUSTION SYSTEM

Source [xvii]

One other effect is that the concentration of all constituents in the recycled flue gas, if not controlled, will increase as compared to an air-fired unit. This is because the higher the flue gas recycle ratio, the higher the concentration of not only CO_2 , but also other constituents in the flue gas. The flue gas recycle ratio is defined as follows:

 Flue Gas
 Mass Flow of Recycled Flue Gas

 Recycle Ratio
 =
 (Mass Flow of Recycled Flue Gas) + (Mass Flow of Flue Gas Exiting the System)

For example, for a recycle ratio of 70%, the concentration of sulfur compounds in the boiler furnace would increase by a factor of approximately 3.3. Thus, for the sulfur content of 2.5% (wt.) in the design coal, sulfur concentration in the furnace may become equivalent to the concentration of a coal containing $\sim 8\%$ (wt.) of sulfur, resulting in excessively high waterwall corrosion rates. Consequently, for oxygen combustion operation SO₂ removal efficiency by the FGD system is governed by the sulfur concentration in the boiler furnace. Similar logic is applicable to the particulate and moisture removal systems, thus allowing increase of CO₂ concentration in the recycled flue gas while maintaining acceptable concentrations of moisture, sulfur compounds, and particulates.

Flue gas recycle ratio is a key design parameter for oxycombustion processes as it is responsible for controlling furnace temperature, maintaining safe and optimal combustion conditions in the furnace, and maintaining balance between heats transferred in the radiant furnace and the convective heat transfer surfaces to achieve required boiler performance. In addition, the flue gas recycle ratio assures that the formation and deposit of ash in the boiler fired with synthetic air (O_2 and CO_2 mix) does not compromise boiler cleanability (reduced ash slagging), as well as allows for boiler operation in oxycombustion mode with the existing metallurgy of the furnace and back pass heat exchangers.

The conclusions from the pilot-scale studies are that the feasibility of oxy-fuel combustion with flue gas recirculation in boiler applications has been demonstrated. Oxy-fuel combustion technology can be used to retrofit existing boilers and has the potential to lower the NOx emissions and increase the efficiency of SOx removal. Hg emissions are possibly also lower than under air firing conditions, CO_2 concentrations in the exhaust gas stream of >90% (db) can be achieved, and no major technical barriers have been identified [^{xx}]. The gross efficiency of an oxy-fuel-fired boiler is similar to that of a comparable air-fired unit or might even be slightly higher due to reduced heat losses resulting from reduced gas volume flow.

However, a number of technical issues were identified that need to be addressed in more detail. Efficient oxygen generation, air ingress into boiler and flue gas cleaning equipment, heat transfer in the boiler, and ash-related issues are all areas that need to be addressed. In addition, ignition and flame stability, emissions, the optimal flue gas recycling ratio, and boiler turndown behavior and transient operation during start-up / shut down must be examined as well.

		Air-l	Fired			Oxygen-Fired	
	No C	apture		apture	Cryo	ogenic	ITM
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
	SC/Air	USC/Air	SC/Air	USC/Air	SC/ASU	USC/ASU	SC/ITM
Output and Efficiency							
Main steam flow	3.581.311	3.100.955	5.113.170	4.217.953	4.968.298	4,193,226	4.419.240
(lbm/hr)	- , ,-	-, -,	- , - ,	-,	- , ,	- , ,	.,,
Turbine heat rate	7,604	6,726	10,945	9,282	10,696	9,093	9,427
(Dtu/KWh)							
(LW)							206,970
Steam turbine generator							
(kW)	583,812	582,651	666,626	650,030	792,512	772,611	713,600
Gross Output							
(kW)	583,812	582,651	666,626	650,030	792,512	772,611	920,570
Auxiliary Power							
Summary							
Econamine FG+ (kW)			21,430	18,830			
Air separation unit (kW)					130,270	119,740	268,970
CO ₂ compression (kW)			47,150	44,192	78,560	67,000	64,950
Base plant power (kW)	30,010	26,770	49,300	41,956	37,490	32,500	34,290
Total Auxiliary Power	30.010	26,770	117.880	104,979	246,320	219.240	368.210
(kW)	;	; · · · -	.,	;			,
	552.002	555.004	540 544	545.054	546.220	552.074	550.040
Net Plant Output (KW)	553,802	555,881	548,746	545,051	546,320	553,371	552,360
	0.970	0.970	0.972	0.972	0.997	0.990	0.902
Dotter efficiency $(HHV)^{r}$	0.879	0.879	0.873	0.873	0.880	0.880	0.893
Coal heat input (HHV)	410,505	304,347	369,747	490,704	505,295	490,138	300,00
(10 ⁶ Btu/hr)	4,790	4,253	6,880	5,795	6,595	5,718	5,833
Natural gas flow							38 831
(lbm/hr)							50,051
Natural gas heat input (HHV) ² (10 ⁶ Btu/br)							885
Total fuel heat input							
(HHV) (10 ⁶ Btu/hr)	4,790	4,253	6,880	5,795	6,595	5,718	6,718
Net plant heat rate	9 (40	7 (5 1	10 520	10 (22	12.074	10 222	10.1(0
(HHV) (Btu/kWh)	8,049	/,051	12,558	10,032	12,074	10,555	12,162
Net plant thermal	39.5%	44.6%	27.2%	32.1%	28 3%	33.0%	28.1%
efficiency (HHV)	57.570	FT.070	<i></i> /. <i>_</i> /0	54.170	20.370	55.070	20.170
Energy penalty ³ (% net	-	-5.1	12.2	7.4	11.2	6.4	11.4
points)						~ • •	
Boiler heat input/(Qcoal -	-HHV + Qc	redits)					

Oxycombustion and MEA Systems Comparative Performance:

² Required for ITM cases

³ Percentage points decrease in efficiency due to CO₂ capture relative to Case 1

Based on the results of a 2008 Powerspan study [^{xviii}], the oxycombustion-based system has $\sim 1\%$ advantage over an MEA-based system in overall plant efficiency (see figure above). With

oxycombustion technology, decreases in overall plant efficiency and increases in the cost of electricity (major contributors to the overall cost of CCS) occur due to the air separation plant (capital cost and power consumption). Therefore, all developments that target a decrease in the cost of oxygen will greatly improve the competitiveness of this technology. Such developments include steady improvements of the cryogenic distillation process (leading to a significant cost decrease, even in the past 10 years), as well as investigations of alternative oxygen supply processes, such as membranes.

Recommendations

Salient features of the compared technologies are summarized in the table below. All listed technologies are either commercially available or projected for commercial deployment by 2015, which is in line with the PA Climate Initiative schedule.

MEA scrubbing is currently the only commercially available technology that has been demonstrated for CO_2 capture from coal-fired boilers flue gas. The largest currently operating MEA facilities are sized for ~400 TPD of product CO_2 per train⁸, requiring an approximate 10x scale up for 400 MWe of equivalent power.

Chilled Ammonia Scrubbing and Aqueous Ammonia Scrubbing technologies have the most promising technical performances. The KS Solvent Scrubbing technology also promises a better performance than an MEA based system. However, both ammonia-based processes and KS solvent process are still in the pilot demonstration stages for coal-fired power plant flue gas treatment application. KS Solvent Scrubbing process has been demonstrated, but only in a chemical plant application. Currently operating pilot plants for all three technologies are sized for less than the equivalent of a 2 MWe slipstream. Scaling from 2 MWe equivalent to the size required for the PA Climate Initiative sites may present a significant risk.

Technical performance of oxycombustion technology is comparable to MEA carbon capture system. The oxycombustion pilot plant at Schwartze Pumpe site is sized at 30 MWth (~10 MWe equivalent). Scaling from 10 MWe equivalent to the size required for the PA Climate Initiative sites may present a relatively lower, but still significant, risk.

Enabling carbon capture process at the existing power-generating unit entails the addition of a carbon capture system (or an ASU for oxycombustion) and CO₂ purification/compression systems, modifications to the existing steam generator and steam cycle/feedwater systems, and additions/modifications to the balance of plant systems. Modification of the existing unit, unlike a "green-field" design, is significantly influenced by its preexisting configuration. The scope of modifications and techniques that could be applied to enable carbon capture at an existing plant is constrained by the existing systems design, space availability, and operating conditions. Each of the PA Climate Initiative host sites is unique and requires a custom approach in establishing best suited

⁸

All operating MEA facilities capturing CO₂ from coal-fired boilers are producing product CO₂ for food grade applications with gas purity exceeding 99.99% (dry basis).

applicability of a carbon capture system. Thus, notwithstanding the risk associated with deployment of new technologies, MEA, ammonia-scrubbing, KS solvent scrubbing and oxycombustion are recommended for more detailed evaluation for their applicability to a carbon capture retrofit of the PA Climate Initiative host sites.

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Features of CO2 Capture Technologies

	MEA	Chilled Ammonia	KS Solvents	Aqueous Ammonia (ECO2)	Oxycombustion
Technology Type	Chemical solvent Absorption	Chemical solvent Absorption	Chemical solvent Absorption	Chemical solvent Absorption	CO ₂ pre-concentration followed by low temperature distillation
Current Status	Four commercial plants ranging in size from 150 to 800 TPD of CO2 from a coal-fired plant flue gas stream.	Pilot plant equivalent to 1.7 MW at We Energies' Pleasant Prairie coal fired plant has been started in early 2008 [^{xix}]	Pilot at J-Power coal fired plant with CO ₂ recovery capacity of 10 T/D, started in Oct 2006 [^{xx}]	Pilot plant equivalent to 1 MW, (CO2 capture capacity of 20 ton/day) started in October 2008 at Burger Power Station, OH	Alstom and Air Products 30 MWth pilot unit at the Schwarze Pumpe site in Germany started operation in the summer of 2008
Projected Commercial Availability	CO2 plant equivalent to 400 MWe power plant is currently available [vii]	Commercial product for selected market segments before the end of 2011	Medium scale ~500 TPD for coal flew gas. Schedule is not specified	120 MWe equivalent systems are planned for 2012 at NRG WA Parish, TX and Basin Electric Antelope Valley, ND	300 MWe oxyfuel demonstration plant is planned for 2015 by Alstom
Inlet Conditions	Atmospheric pressure/110°F [v]	Absorber operates at temperature of 35- 60°F,	Atmospheric pressure/110°F	Suitable for post combustion flue gas with at least 1000 ppmv of S	VN
Inlet Contaminants	SOx ≤ 10 ppmv NO2 ≤ 10 ppmv	$SO2 \sim 50 \text{ ppmv}$ $SO2 \sim 40 \text{ ppmv} \text{ [xxi]}$	SOx ≤ 1 ppmv [xi]	Integrated with Powerspan ECO multi-pollutant control system [v]	NA
Steam Btu/Ib CO ₂	\sim 1,500-1,800 (c)	~400-700 [xiv]	\sim 1,300	~500 [xxii]	Relatively small quantity for ASU
Power kWh/ton CO ₂ (a)	~125 [xiv] to ~150 [xv]	\sim 77 [xiv]	~180	~ [vz] 00~	~375
CO ₂ Recovery, %	≥ 90	≥ 90	90 (design condition) [i]	Design condition ~90% [v]. Demonstrated ~88% [xxiii]	≥ 90
CO ₂ Purity, %	≥99	[ixx] %	≥99.9 (dry base)	Not reported	66⋜

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	MEA	Chilled Ammonia	KS Solvents	Aqueous Ammonia (ECO2)	Oxycombustion
Developer / Supplier	Fluor Daniel, Lummus Global, Dow Chemical	Alstom	Mitsubishi Heavy Industries.	Powerspan	Alstom, Babcock & Wilcox, Foster Wheeler, Doosan Babcock
Comments	30-50% energy penalty for power plant retrofit, current Amine cost ~ \$1500 per ton.	30-40% energy penalty for power plant retrofit, Ammonia current cost ~ \$300– \$400 per ton. high pressure regeneration ~ 20 bar [^{xxiv}].	Negligible corrosion; regeneration at 110~120°C [xw]	This process is integrated with the ECO process, which provides NOx , SOx , and particulate control [v] Demonstrated NH3 slip is 1-2 ppm [xxiii]	
Limitations and concerns	High energy penalty	Ammonia volatility can be an issue – reported NH3 slip is 10 ppm. Absorption rate is slower than that of MEA [xxvi]	Future plans with respect to CO ₂ capture from coal flue gas are uncertain	To be competitive requires a significant SOx concentration in the feed stream	Product CO ₂ with likely relatively high O2 content
Jotes:	-				

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Energy for CO₂ capture, conditioning and compression. Regeneration energy varies with technologies from different providers. <u>e</u>a

Notes:

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List of Acronyms and Abbreviations:

Btu	British thermal unit
CCS	Carbon capture and sequestration
CCT	Carbon capture technology
CO ₂	Carbon dioxide
DEA	Diethanolamines
EPRI	Electric Power Research Institute
ESA	Electric swing adsorption
FGD	Flue gas desulfurization
GJ	Giga joule
gpm	Gallons per minute
h, hr	Hour
H_2	Hydrogen
H_2O	Water
H_2S	Hydrogen sulfide
IGCC	Integrated Gasification Combined Cycle
ILs	Ionic liquids
KEPCO	Kansai Electric Power Company
kW	Kilowatt
lb	Pound
lb MDEA	Pound Methyldiethanolamine
lb MDEA MEA	Pound Methyldiethanolamine Monoethanolamine
lb MDEA MEA mol%	Pound Methyldiethanolamine Monoethanolamine Percentage by molar composition
lb MDEA MEA mol% MPa	Pound Methyldiethanolamine Monoethanolamine Percentage by molar composition Mega Pascal absolute
lb MDEA MEA mol% MPa MTR	Pound Methyldiethanolamine Monoethanolamine Percentage by molar composition Mega Pascal absolute Membrane Technology and Research,
lb MDEA MEA mol% MPa MTR	Pound Methyldiethanolamine Monoethanolamine Percentage by molar composition Mega Pascal absolute Membrane Technology and Research, Inc.
lb MDEA MEA mol% MPa MTR MW	Pound Methyldiethanolamine Monoethanolamine Percentage by molar composition Mega Pascal absolute Membrane Technology and Research, Inc. Molecular weight
lb MDEA MEA mol% MPa MTR MW MWe	Pound Methyldiethanolamine Monoethanolamine Percentage by molar composition Mega Pascal absolute Membrane Technology and Research, Inc. Molecular weight Megawatt electric
lb MDEA MEA mol% MPa MTR MW MWe N ₂	Pound Methyldiethanolamine Monoethanolamine Percentage by molar composition Mega Pascal absolute Membrane Technology and Research, Inc. Molecular weight Megawatt electric Nitrogen
lb MDEA MEA mol% MPa MTR MW MWe N ₂ NGCC	Pound Methyldiethanolamine Monoethanolamine Percentage by molar composition Mega Pascal absolute Membrane Technology and Research, Inc. Molecular weight Megawatt electric Nitrogen Natural gas combined cycle
lb MDEA MEA mol% MPa MTR MW MWe N ₂ NGCC NH ₃	Pound Methyldiethanolamine Monoethanolamine Percentage by molar composition Mega Pascal absolute Membrane Technology and Research, Inc. Molecular weight Megawatt electric Nitrogen Natural gas combined cycle Ammonia
lb MDEA MEA mol% MPa MTR MW MWe N ₂ NGCC NH ₃ Nm ³	Pound Methyldiethanolamine Monoethanolamine Percentage by molar composition Mega Pascal absolute Membrane Technology and Research, Inc. Molecular weight Megawatt electric Nitrogen Natural gas combined cycle Ammonia Normal cubic meter
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lb MDEA MEA mol% MPa MTR MW MWe N ₂ NGCC NH ₃ Nm ³ Nm ³ /d NO	Pound Methyldiethanolamine Monoethanolamine Percentage by molar composition Mega Pascal absolute Membrane Technology and Research, Inc. Molecular weight Megawatt electric Mitrogen Natural gas combined cycle Ammonia Normal cubic meter Normal cubic meter per day
lb MDEA MEA mol% MPa MTR MW MWe N ₂ NGCC NH ₃ NH ₃ Nm ³ Nm ³ /d NO NO ₂	PoundMethyldiethanolamineMonoethanolaminePercentage by molar compositionMega Pascal absoluteMembrane Technology and Research, Inc.Molecular weightMegawatt electricNitrogenNatural gas combined cycleAmmoniaNormal cubic meterNormal cubic meter per dayNitrogen monoxideNitrogen dioxide
lb MDEA MEA mol% MPa MTR MW MWe N2 NGCC NH3 Nm3 Nm3/d NO2 NO2 NOx	Pound Methyldiethanolamine Monoethanolamine Percentage by molar composition Mega Pascal absolute Membrane Technology and Research, Inc. Molecular weight Megawatt electric Mitrogen Natural gas combined cycle Ammonia Normal cubic meter Normal cubic meter Normal cubic meter per day Nitrogen monoxide Nitrogen dioxide Oxides of nitrogen
lb MDEA MEA mol% MPa MTR MW MWe N ₂ NGCC NH ₃ NH ₃ NH ₃ Nm ³ /d NO NO ₂ NO ₂	PoundMethyldiethanolamineMonoethanolaminePercentage by molar compositionMega Pascal absoluteMembrane Technology and Research, Inc.Molecular weightMolecular weightMegawatt electricNitrogenNatural gas combined cycleAmmoniaNormal cubic meter per dayNitrogen dioxideNitrogen dioxideOxides of nitrogenOxygen

ppmv	Parts per million by volume
PSA	Pressure swing adsorption
SCPC	Super-critical pulverized coal
SCR	Selective catalytic reduction
SO_2	Sulfur dioxide
SOx	Oxides of sulfur
TSA	Temperature swing adsorption
TBD	To be determined
wt%	Percentage by weight