AMERICAN CLEAN SKIES FOUNDATION

CONFERENCE PROCEEDINGS

November 4, 2011

FROM A BRIDGE TO A DESTINATION

GAS FIRED POWER AFTER 2020

A CARBON CAPTURE AND STORAGE LEADERSHIP FORUM FOR NATURAL GAS POWER PLANTS

FROM A BRIDGE TO A DESTINATION

GAS FIRED POWER AFTER 2020

A Carbon Capture and Storage Leadership Forum for Natural Gas Power Plants

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About the Conference and Additional Resources

On November 4, 2011, ACSF held a public forum in Washington, D.C., on Carbon Capture and Sequestration (CCS) for natural gas-fired electricity generation. The forum sought to fill a gap in U.S. policy discussions about the future of gas-fired power plants. Dubbed *From a Bridge to a Destination: Gas Fired Power After 2020*, the forum brought together more than a dozen presentations from the power industry, academic institutions, public interest groups, think tanks and the government. Participants included the Clean Energy Group, Great Plains Institute, ACSF, President's Interagency Task Force on CCS, California CCS Review Panel, MIT, Carnegie Mellon University, the National Resources Defense Council and EPA.

Greatly expanded use of natural gas will lead to steady reductions in the carbon intensity of the U.S. power grid—up to a limit—but the U.S. is likely to need CCS to realize the full benefits of gas-fired power over the long term, especially if there is widespread future regulation of greenhouse gas emissions.

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Chief Executive Officer,
American Clean Skies Foundation

GREG STAPLE is the CEO and Board Member of the American Clean Skies Foundation (ACSF). A former partner at the international law firm Vinson & Elkins, he assumed the role of CEO of ACSF in December 2009. Greg is an expert on federal energy regulations and previously co-directed Vinson & Elkins' Washington, DC, climate change program. In 2010, he organized and co-chaired the joint ACSF-Bipartisan Policy Center National Task Force on Stable Natural Gas Prices. His recent work has focused on the regulatory factors affecting fuel use in the electricity sector, including EPA, FERC and state PUC actions. Greg's essays have appeared in numerous publications, including The Environmental Law Forum, Legal Times of Washington and The American Journal of International Law. In addition to practicing law for over 25 years, he has been a consultant to the World Bank and is the founder and former CEO of the TeleGeography publishing group. He received his J.D. from the University of Michigan and his undergraduate degree in political economy from the University of Rochester.

A CARBON CAPTURE AND STORAGE LEADERSHIP FORUM FOR NATURAL GAS POWER PLANTS

November 4, 2011, Washington, D.C., the Hotel Monaco

Opening Remarks (edited) of Gregory C. Staple, CEO, ACSF:

Framing the Issues

We are delighted to have such a significant turnout here at what, to our knowledge, is the first U.S. leadership forum on carbon capture and sequestration for natural gas-fired power plants. Our shorthand reference for the topic is "CCS For Gas." I see a number of familiar faces out there, and some folks I got to know last night at the dinner for our speakers. But there are also a fair number of people I don't know so let me start out briefly by saying something about the American Clean Skies Foundation; something about our thinking in putting together today's program; and something about what we expect to get out of it. I also want to talk about your role in this – we want you all to be active participants and, in fact, you are our initial inaugural brain trust.

The American Clean Skies Foundation is a Washington, D.C. based non-profit, founded in 2007. The impetus for the organization was largely to let folks in Washington and elsewhere know about the increasingly abundant and affordable supply of natural gas in this country and what role gas might play in America's energy future, both in the power sector and, as importantly, I think, in the transportation sector where fuel shifting at scale, could begin to address one of America's long-running economic conundrums: our over-reliance on imported oil. In the last year, however, we've focused most of our efforts on the power sector, commissioning reports, bringing folks together for conferences, workshops, roundtables and addressing specific concerns people have about using an expanded volume of natural gas for generating electricity.

In this regard, I want to draw attention at the outset to two reports which in some ways set the table for what we are going to discuss today. The first of these is the MIT report issued in the summer of this year on the Future of Natural Gas. This was about three years in the making and there was a preliminary report in June 2010 that the The New York Times covered. The report looked at the supply horizon for natural gas -- MIT did its own bottom up review of the available data -- and then MIT also looked at how natural gas might be used in the power sector as well for feedstock and also as a heat and power source for the industrial sector. So with the supply situation having been reviewed by MIT, in 2010, we convened with the Bipartisan Policy Center, a cross-sector task force

that produced a second report on options for ensuring stable natural gas prices. We looked at various tools from hedging to long term contracts to joint ventures. Copies of both of these reports are available on a back table and, if you haven't seen them, please pick them up. You can also go online and download a pdf of each report.

So, these reports provided a baseline for today's event because unless we were convinced that there was an ample supply of gas and that it would be available for the power generation sector at an attractive price, and hence, that gas would play an increasingly important role in electric generation in this country, then we probably wouldn't be talking about the need to take a hard look at the potential for capturing carbon from gas-fired power because it would be a declining slice of generation. And, actually, that's what many people expected five or seven years ago. But I think today there is every indication that the opposite is the case; that we are looking at a future in which natural gas-fired power will be a growing slice of generation. You can see that in just the last two or three years coming back from a savage economic downturn that gas has gained nationally perhaps one or two percent market share. I recently looked at the PJM market monitor to see how gas is doing in the northeast, and mid-west, as well, and it has gained about four or five percent since 2008 or so because gas has increasingly being dispatched at the margin instead of coal. When we look at permits for new construction, we also see that gas-fired power plants are capturing at least half the market with wind capturing much of the rest. John Rowe, Chairman and CEO of Exelon, one of the longest serving utility executives, recently put it this way: "Natural gas is queen. It is domestically abundant and inexpensive and is the bridge to whatever energy future prevails."

So with gas getting the lion's share of new investment, and existing gas-fired plants, particularly combined cycle power plants running at higher rates largely because of marginal fuel costs, and over the mid-to longer term, running more in order to meet reliability concerns because as we know, the current slate of EPA regulations is likely to lead to the retirement of perhaps 30 gigawatts or more of existing old and largely dirty and inefficient coal-fired power -- it seems apparent to us that the mix of generation facilities is likely to tilt much more heavily toward gas-fired power. And we know, based upon the full fuel cycle analysis that people in this room have worked on, as compared to coal, gas-fired power produces perhaps 50-60% less greenhouse gas emissions.

Nevertheless, we also know that if you ramp up the size of the fleet over time, that increment of emissions is still significant. So our thinking is that if gas is playing a larger role, if the combustion emissions are not insignificant, particularly if you are talking

about long-term goals of carbon reduction of 80% below 2000 values as the MIT report did, you can't ignore CO2 emissions from gas-fired power. We were also influenced by one of the MIT report's findings that, looking forward 25, 30 years, it appears that on a per megawatt basis capturing carbon from the flu gas stream from combined cycle plants may, in fact, be more cost effective than capturing CO2 from coal-fired plants.

But I want to stress today that both of these observations are still something of a hypothesis. That is, our hypothesis is that gas is going to play a larger role in the power sector and that, looking forward some years, capturing CO2 from gas plants might end up being more cost effective. So, we thought, let's bring people together. Let's bring the real experts together and thrash this out for a day. Let's reach out to the utilities, to government to research labs, to vendors to the consulting community and put folks around the table.

I didn't do all of that myself, of course. Jerry Hinkle our Vice President for Policy and Research is the man largely responsible for the day-to-day work of organizing this event. And he also wrote a very useful background paper which is already available on our website at cleanskies.org/ccsforum. I want to flag that and also advise that this url is the place to look for all the additional papers from today's event. Jerry was helped by Tom Curry, a Vice President at MJ Bradley who will also speak later today and has written a separate background paper which I commend to you.

So now let me clarify the focus of today's events and also put two or three questions at the outset that we might all have in our minds as the day goes on.

First, a clarification. Today, we are going to focus on the capture part of the CCS equation. That's where the bulk of the expenditure goes. That's where the real costs are. And also we are focusing on this part of the challenge because the transport and sequestration part are in some ways common to capturing carbon from other fuel sources and there is a lot of work being done in those areas. So, that's one of the caveats here. Hence, if you don't hear much today about transport and sequestration, that is intentional.

In addition, we are not going to focus today on one of the main economic drivers right now for capturing CO2 which is, of course, pumping it underground in order to enhance oil recovery or gas recovery, in some cases. So what are we going to talk about? Here are three questions. First, in what time frame we are likely to need proven, commercial

options for carbon capture at gas-fired power plants? Are we talking 2025, 2035, or 2040? Let's think about that.

Second, based on the current R&D demonstration projects, are we really likely to have commercial scale technology available at the time when we think, due to carbon policy, carbon prices, or regulation that, yes, there is a consensus that capture is the way to go.

Thirdly, if we're unlikely to have the technology we need at scale proven in that time frame, what types of private and public sector efforts are needed to close the gap and how might those efforts differ, when it comes to gas-fired power plants, from what's now being done and being funded for coal-fired plants?

So that's a lot to think about, but I believe the questions I have raised are recurring ones that will come up throughout the day and certainly underpin our thinking in pulling this conference together. So now, let me hand off to our first panel with Carl Bauer. Thank you very much.

Vice President of Policy & Research,
American Clean Skies Foundation

JEROME HINKLE is the Vice President for Research for the American Clean Skies Foundation. Prior to joining the Foundation, he was Vice President for Policy and Government Affairs at the National Hydrogen Association, and served for several years as a Brookings Fellow for Senator Byron Dorgan, helping to craft legislation on advanced energy technologies, including the Hydrogen Title in the Energy Policy Act of 2005 and several others. For the US Department of Energy, he managed R&D programs in alternative engines and fuels, was a senior analyst in environmental policy and international energy security, and the chief economist for the US Naval Petroleum and Oil Shale Reserves. Education includes physics, mathematics and aerospace engineering, with advanced graduate work in international politics, economics and public policy.

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Can CCS Bring Gas from Bridge to a Destination?

A literature review

Jerome Hinkle

Vice President, Policy and Research

American Clean Skies Foundation

November 30, 2011

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Strategic Value Since 2005, there has been a dramatic upward reassessment of North America's long term natural gas resource base, largely stemming from the new potential of shale and other unconventional resources. More efficient and cheaper production techniques have increased shale gas supply at steadily lower cost, radically changing the future price outlook for natural gas and making it increasingly competitive as a base load fuel for electricity generation. Stricter environmental limits on the emissions from coal-fired generation have also led to increased interest in substituting gas-fired generation for the oldest and least efficient plants in the coal fleet.

Although more efficient combined cycle gas turbine (CCGT) facilities emit roughly 60% less CO2 per kilowatt hour than conventional coal generators, total global warming emissions from gas-fired power generation will become significant as more and more coal fired facilities are displaced. That has raised alarms in some environmental circles where there has been support for gas as a bridge fuel on the road to a zero carbon power sector—until lower carbon alternatives, like wind and solar, are available in the largest markets. These variable energy resources (VERS) will also require quick-ramping gas plants to help balance system demand and supply variations in the quest for a lower carbon grid.

Thus, over the mid to longer term, whether natural gas is a bridge rather than a new foundation fuel—as many in the natural gas industry desire—will likely depend on whether the current CO2 footprint of gas-fired power can be substantially reduced via carbon capture and storage (CCS).

U.S. RD&D has concentrated on solving the formidable problems of CCS for coal, which was once thought to be our most abundant domestic resource. The US has no large scale gas power plant CCS demonstration projects underway. The status of current RD&D related to CCS is further described in presentations from the Forum noted below.

ACSF held a public forum on CCS for natural gas in Washington November 4, 2011, at the Hotel Monaco. This event highlighted critical issues by bringing together top experts to focus on a key clean energy deployment challenge that is now completely absent from U. S. policy discussions. Greatly expanded use of gas will lead to steady reductions in the carbon intensity of the US grid—up to a limit—but the US is likely to need CCS to realize the full benefits of gas over the long term, especially if there is widespread future regulation of greenhouse gas emissions (GHGs) outside California. Our forum was shaped by these concepts:

- Subject to eventual regulation of GHGs, CCS for gas might need to be commercially deployed after 2025—large scale demonstration projects will be required several years before
- California will implement a cap-and-trade system that covers electricity generation and imports by 2012; CCS is an approved abatement technology
- even without strong federal climate legislation, several states are moving slowly forward on climate regulation
- abundant analyses show increased demand for gas to replace coal, perhaps accelerating the need for CCS.

The Forum included several commissioned expert analyses, representation from the Clean Energy Group, Great Plains Institute, ACSF, President's Interagency Task Force on CCS, California CCS Review Panel, leading manufacturers and researchers, involved NGOs and top policy thinkers. All the slide presentations, agenda and a video of the event are on our website at www.cleanskies.org/ccsforum .

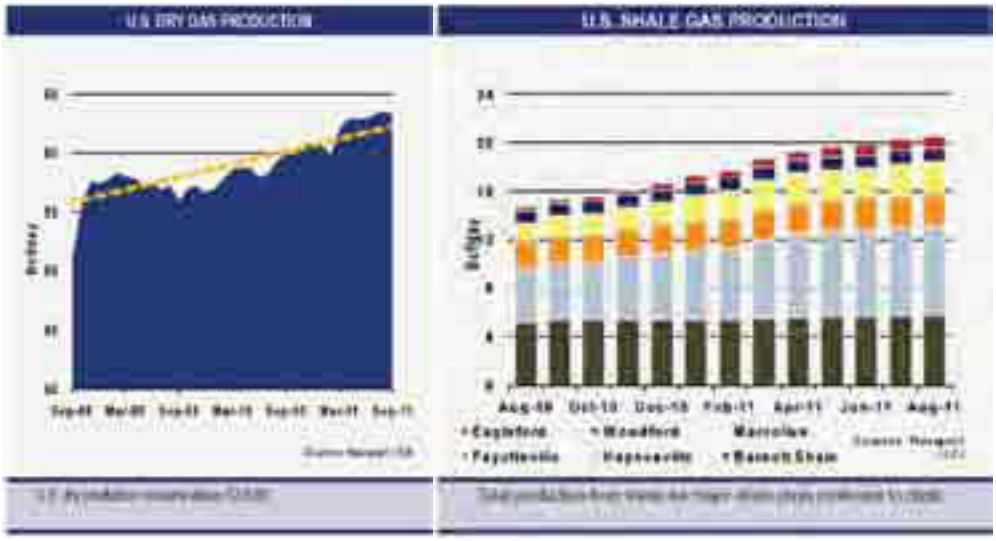
Background As more mature and unscrubbed coal plants face continued economic and regulatory pressures, there is an opportunity to significantly reduce emissions from power plants by increasing the consumption of gas in the generation fleet. Growth in gas demand in the power sector also is expected as existing Combined Cycle Gas Turbines (CCGTs, or NGCCs, as they are often called) are more fully utilized and more gas plants are built to replace geriatric coal, while providing firming integration with Variable Energy Resources (VERs) to build a more flexible grid. However, increased gas consumption will not reduce greenhouse gas emissions to a level that would meet the aggressive mid-century targets discussed during international climate talks outlined by the Obama Administration, and embodied in the climate legislation that passed the House of Representatives in the last Congress.

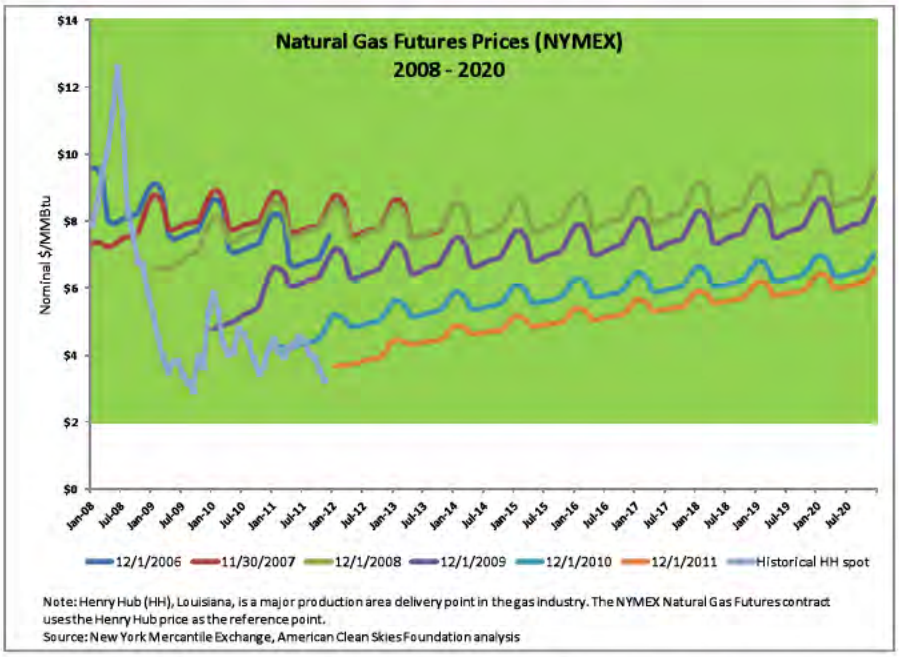
ACSF has conducted a literature review to set the stage for discussions at the forum. This background white paper pulls together information on the potential timing for CCS deployment on gas-fired power plants and provides an overview of the current state of

CCS technology deployment. A key purpose for the ACSF forum on CCS for gas is to develop a strategic direction to encourage funding broader investments in critical post combustion capture demonstrations for gas, and help induce timely commercial deployment of CCS.

Across a wide variety of sources, there is no detectable strategic direction for action on evolving the grid in the US towards CCS for gas plants. CCS for coal has always been considered a more formidable technical challenge, and until the last few years with the advent of shale gas, was seen as the predominant domestic fuel resource for electric power. This is also somewhat a construct of coal states and the electric power industry having created an outsized role for coal in legislation and government RD&D funding.

Converging factors Two charts from Navigant Consulting, utilizing EIA data, show how influential shale gas production has become in the US. Approximately 29% of U.S. dry gas production is now from shale gas. This supply stream bolsters overall gas price stability expectations, as shown in the following chart of NYMEX gas futures prices (1). Prices during late 2011 have moved steadily lower, with spot price at Henry Hub just $3.53/mmBTU.





Note: Henry Hub (HH), Louisiana, is a major production area delivery point in the gas industry. The NYMEX Natural Gas Futures contract uses the Henry Hub price as the reference point.
Source: New York Mercantile Exchange, American Clean Skies Foundation analysis

Figure 6 illustrates how an energy price index for coal, gas and oil has varied since 1995 (1)—by Jan 2010, gas price has diverged sharply from that of coal and this trend continues, especially as more Appalachian coal is exported.

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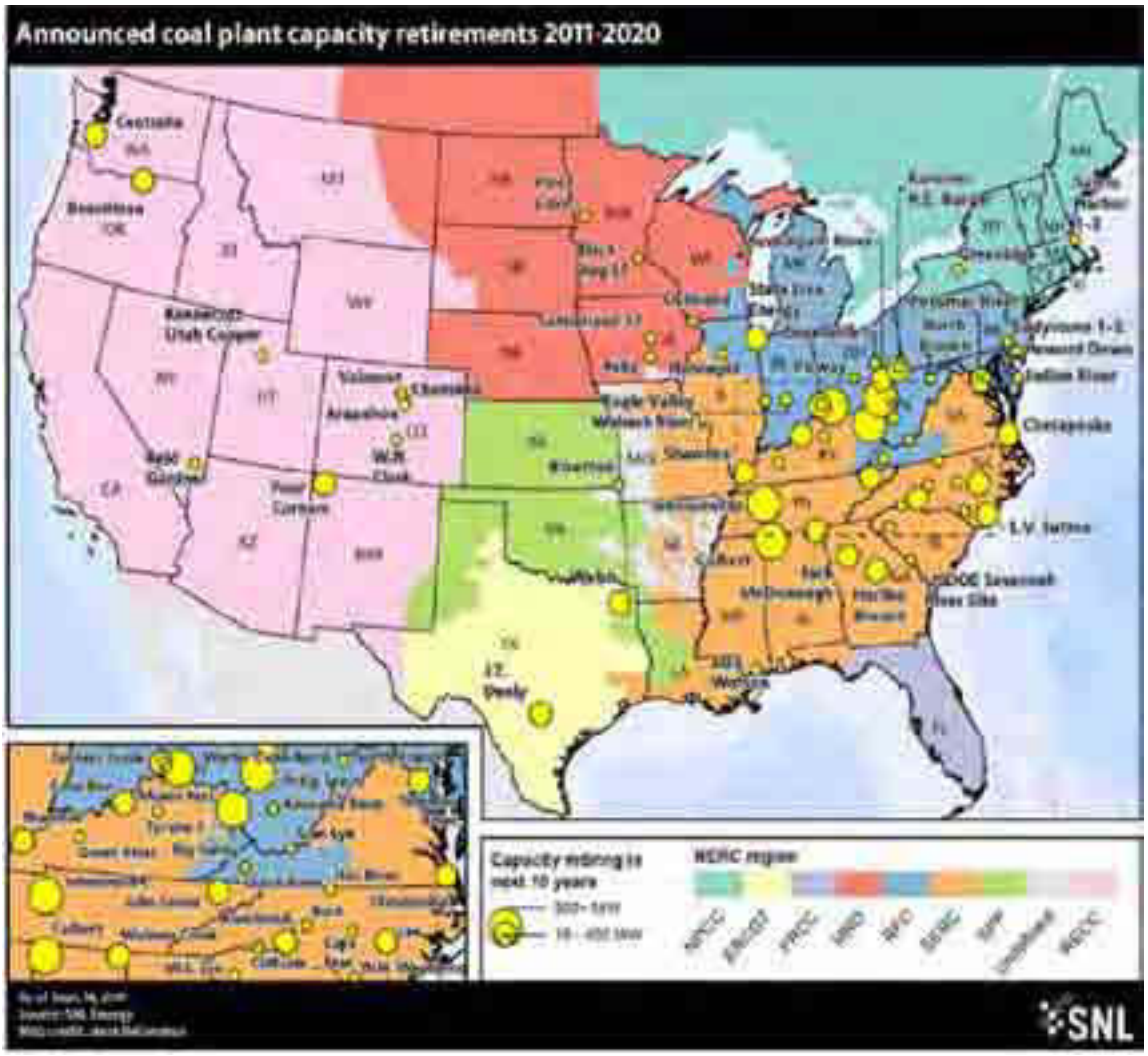
Demand for gas in the electricity sector for power generation is being aided by a stream of retirements of older coal-fired powerplants. As the SNL map shows, over 26 GW of coal generating capacity will be retired between 2011-2020. Depending upon reserve capacity and reliability requirements, some of this would be substituted by new gas capacity, and other plants may simply be unneeded in satisfying fairly flat electricity demand projections.

Announced coal plant retirements recorded by SNL have expanded since the beginning of 2011:

- February 2011—16 GW
- June 2011—23 GW
- September 2011—26 GW
- Deutsche Bank Climate Change Advisors, November 2011—60 GW by 2020, with another 92 GW retired by 2020-2030
- Fitch Ratings, in late November, estimates at-risk coal capacity to be 83 GW
- Other studies estimate a range of 35-101 GW between 2010 and 2020.



Driven by market forces, a growing fuel price gap between coal and gas, regulatory pressures from Clean Air Act enforcement actions, profitability concerns and grid reliability requirements, the closing of marginal coal plants creates an historical opportunity for building new NGCCs in the U.S. Deutsche Bank estimates that over 500,000 new net jobs could be created by the grid mix transformation they foresee, shown in Exhibit 1, which compares their vision of a future U.S. grid mix with that of the Reference Case of the Energy Information Administration's *Annual Energy Outlook 2011*.

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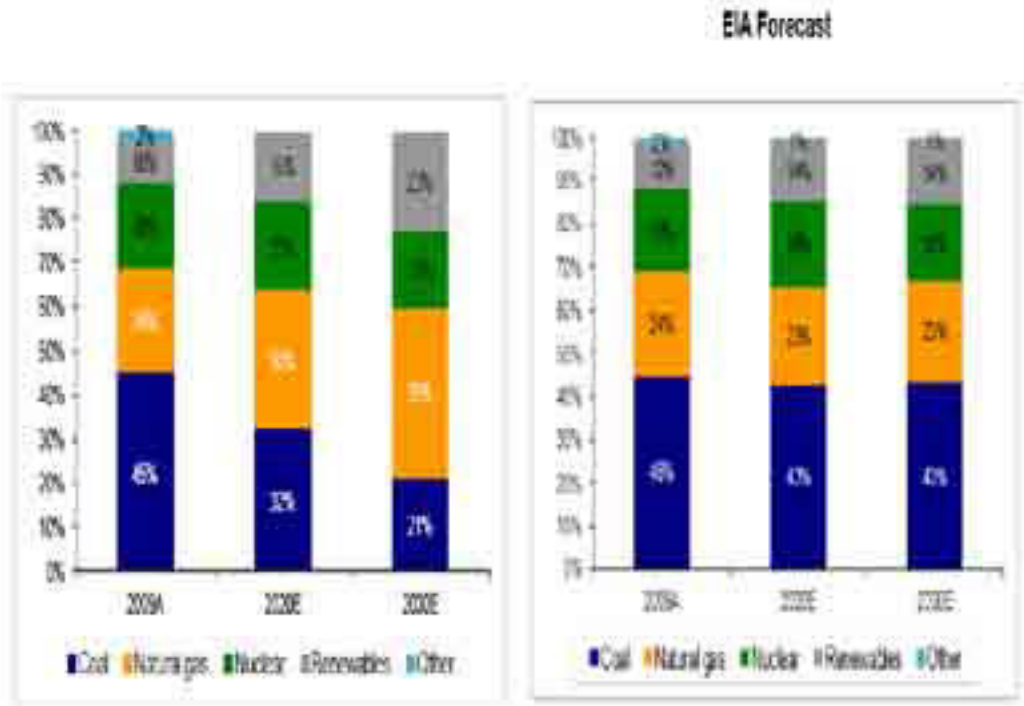
Exhibit 1: DBCCA vs. EIA Electricity Supply Mix Forecasts, 2020 and 2030 (% MWh)



Their scenario is notable for the large differences in gas—39% of generating capacity by 2030, vs only 23% in EIA's, while renewables are 23% of capacity vs 14% (2).

The collective effect of the factors detailed above is to raise the likelihood that a much larger amount of gas will be used in the electric power sector by 2030-2050, sharply diminishing the sheer amount of CO_2, NO_x, SO_2, particulates and mercury emitted from the power sector, and raising its overall energy conversion efficiency. This eases the carbon emission problem with or without carbon regulation.

I. Why CCS for gas?

As the electricity grid evolves, when does uncaptured carbon from gas begin to become a challenge? It depends greatly on the development and stringency of Federal limits on greenhouse gases, and the expansion of regulation of greenhouse gases at the State or regional level.

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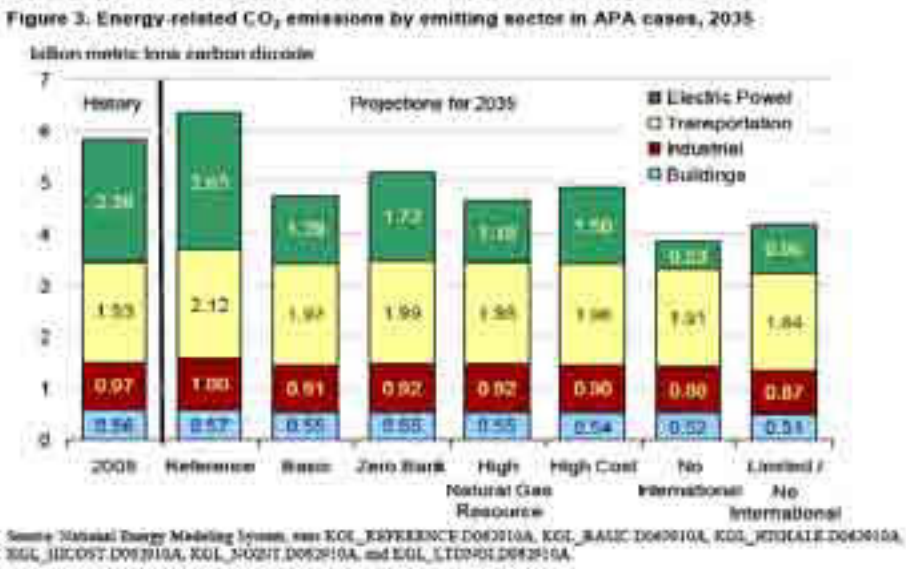
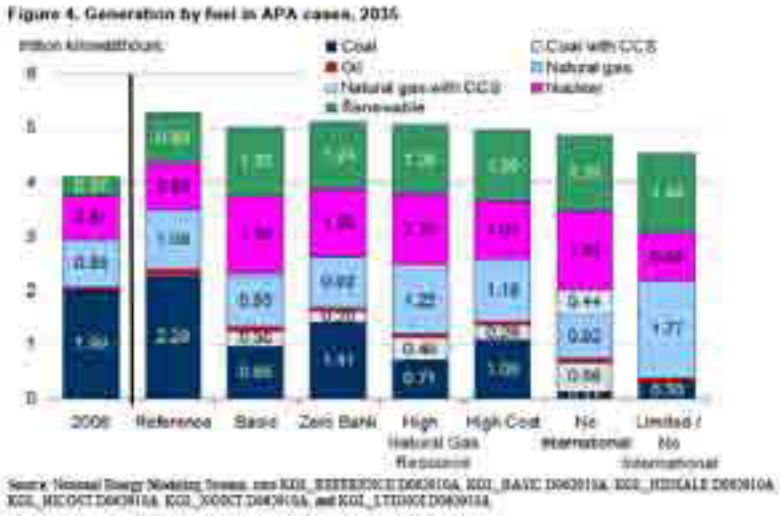
The combination of market forces, relative cost variation between gas and coal, and EPA regulations on coal plants will affect fundamental supply and demand shifts. A frequently cited climate scenario is to reduce greenhouse gas emissions to 80% below 2005 levels by 2050. A publically available large scale analysis that is illustrative of such a target is EIA's *Energy Market and Economic Impacts of the American Power Act of 2010* (July 2010) (3). Both the bill and the analysis have had their faults and detractors, but the EIA work evaluates the many splendored impacts of the Kerry-Graham-Lieberman climate bill that eventually failed to come to the Senate Floor for a vote in 2010. This was based on the Waxman-Markey bill that passed the House in 2009.

The bill's leading goal was to cut GHGs by 17% by 2020 and 83% by 2050. The impacts on CO2 emissions catalogued by this EIA analysis is an extreme case in today's political framework, but it is useful to show the outer bounds of what might be expected from the power sector. Such analyses by both EIA and EPA may offer hints about the need and timing for CCS, and are a useful starting point for our discussion.

The most stringent domestic emissions scenario in the EIA study is the "No International" case (NI-no int'l. carbon offsets), which appears to have the most severe constraints on the Power sector. Figure 3 shows the energy-related CO2 in 2035 by sectors. The "High Natural Gas" (HNG) case assumes doubling the supply of shale gas.





Compared to 2008, total CO2 emissions from the US drop 34% in the NI case by 2035, and 78% in the Power sector. Since the APA was primarily designed to cut emissions from the Power sector, which has some of the lowest cost potential emission reductions, Transportation goes from 1/3 of the CO2 in 2008 to ½ by 2035, while Power's share of CO2 sharply decreases from 40.5% to 13.8% in the same time span.

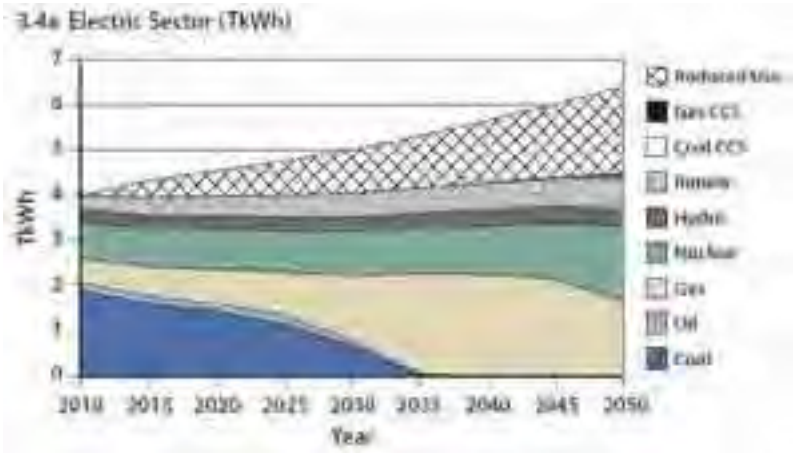
Fig. 4 details the Power sector fuel use. Here is how the US grid mix changes:

Fuel	**2008**	**2035 (NI)**	**2035 (HNG)**
Renewables	9%	29%	25%
Nuclear	20%	30%	26%
Natural Gas	22%	17%	24%
Natural Gas w/CCS	-	9%	1%
Coal	49%	2%	14%
Coal w/CCS	-	12%	8%
Carbon Intensity (kg CO2e/MWh)	583	110	224

Either case shows a dramatic decrease in coal-based electricity generation, with a very strong boost for renewables and nuclear largely due to incentives in the bill for coal, wind, solar and nukes—and the very high gas prices remedied in AEO 2011, partially at ACSF insistence. Gas enjoys a moderate increase in usage in either case (combining the natural gas and natural gas with CCS values). Total electricity demand increases over 2008 by 18% in the HNG case and 15% in the NI case by 2035 (4).

Note that the HNG case requires very little CCS for gas by 2035, but Power sector Carbon Intensity (CI) is far higher. The carbon intensity of the US grid plummets under the more severe NI case, dropping from 583 kg-CO2/MWh to 110 kg-CO2/MWh—44% less than California's in 2008, the lowest by far in the US.

A similar simulation was done by MIT in their study, *The Future of Natural Gas* (June 2011)(4), but they only analyzed a 50% reduction in CO2 from the electric sector by 2050, as opposed to an 83% economy-wide reduction. Fig. 3.4a shows the need for the merest sliver of CCS for gas by 2045-2050, with the grid mix evolving to coal at 6.2%, gas 27.7%, nukes 30.8%, and renewables 12.3% by 2030—rather different than the mixes shown in the DBCCA charts on p8.



Remarkably, energy efficiency and demand response command 30.7% of electricity "use". Hence actual projected electricity demand is nearly flat through 2050.

These two studies invite some comparison, but it is limited by different approaches. Many linked impacts are wildly nonlinear. Generally, it would appear that more stringent carbon caps accelerate CCS for both coal and gas, especially beginning in 2016-2020 in the EIA NI case, where nearly 9% of the grid in 2035 needs CCS for gas (12% for coal). In the HNG case, CCS is barely needed for gas by 2035. Electricity from renewables in the MIT study is partially forced out by nukes and energy efficiency, but the associated carbon and electricity prices are higher—gas is $16/mcf in the MIT study by 2035, and electricity is $.21/kWh, while in the EIA study gas is $10.61-$15.49/mcf, with electricity $.13-$.14/kWh.

This yields two different answers about when to begin deploying CCS for gas, and how much:

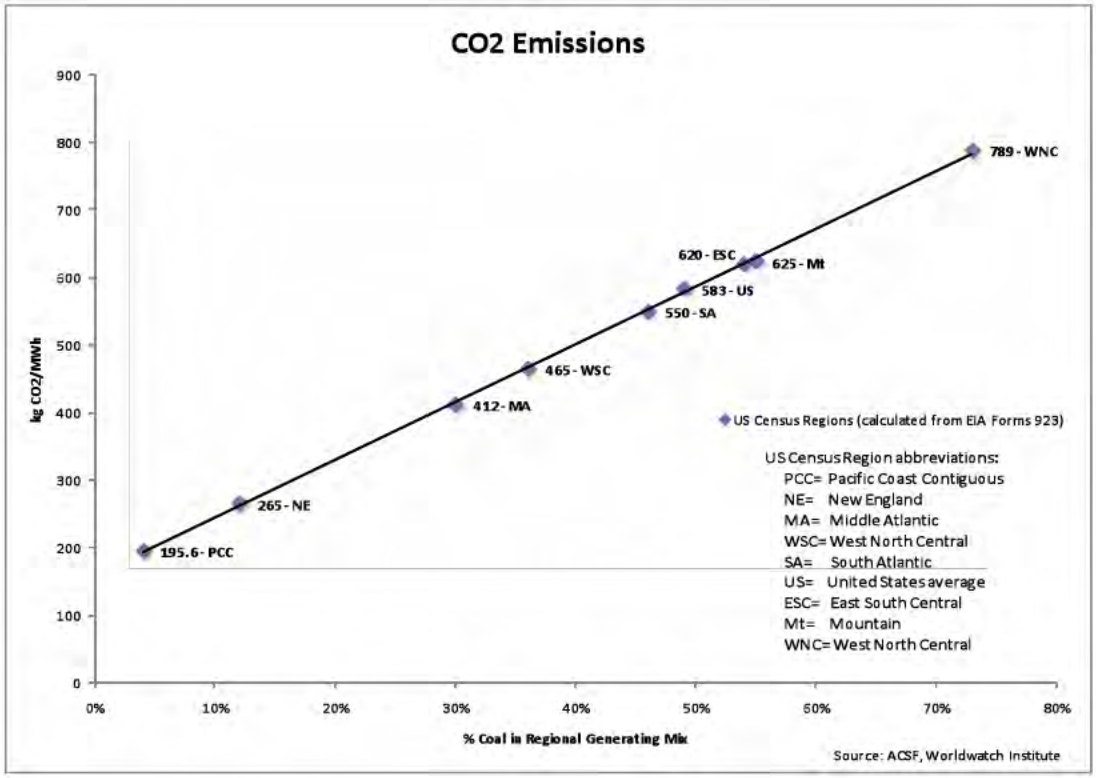
- CCS for gas starts to appear between 2016 and 2020 in the EIA scenario with the most severe CO_2 reduction, where by 2035 about 9% of electricity is generating using gas equipped with CCS, and
- Barely any CCS for gas appears by 2045-2050 in the MIT evaluation of a much milder policy—not put forward in Congress—but attended by higher costs and far more gain in electricity demand reduction.

Regional carbon intensity A different approach may lend further insight into the timing of deployment of CCS for gas. Fig 3 from ACSF's formal comments to the Department of Energy (DoE) on full fuel cycle analysis (5) shows the CO_2 emissions for the US grid and its nine Census Regions. Using the grid mixes from the above EIA study, we can estimate CO_2 intensity as a function of % coal in the mix—but this is mainly correct for US electricity demand levels close to those for 2008—a fetching assumption if one expects little electricity demand growth for several years.

EIA NI in 2035 shows a grid mix of 29.5% renewables, 14% coal and 26.4% for natural gas. Such a scenario would correspond to a carbon intensity of about 285 kg-Co_2/MWh, slightly higher than New England's carbon intensity (CI) in 2008, but far lower than the current US average of 583 kg-CO_2/MWh. Hence we might expect that CCS for gas would be needed if any region of the US was to achieve a CI much above Calfornia's at 196 kg-CO_2/MWh, or the US national CI averages above about 200-250 kg-CO_2/MWh—and if national carbon regulations similar to Kerry-Graham-Lieberman were to be implemented.

Yet another view comes from an extensive analysis of the effects of new EPA regulations under the Clean Air and Clean Water Acts on the US grid by Deutsche Bank Climate Change Advisors (DBCCA), *Natural Gas and Renewables: A Secure Low Carbon Future Energy Plan for the Unted States* (November 2010)(6). DBCCA expect that a combination of stiffening several regulations on emissions and cooling water from coal plants will combine with market forces to materially alter the cost relationships between coal, renewables and gas, moving the US grid by 2030 to a very different mix: coal 20%, down from 47% in 2009; renewables grow to 20% from 10%; gas 35% up from 23%; and nukes 16% down from 20%. A grid mix like this could have a CI of about 220-335 kg-CO_2/MWh.

Fig. 3



The ACSF report (5) observes that in the 2015-2040 time frame the grid needs to evolve: "Our analysis suggests that the US would require a generation mix based on roughly 20% advanced coal, 35% natural gas and 45% ZEG (zero emission generation)..." (a CI of ~325 kg-CO2/MWh, or 44% less than 2008). This is a somewhat different scenario than the one cited from the EIA APA evaluation, especially for gas, nukes and renewables, but quite close to the DBCCA estimates. Their report represents more recent and complete thinking about the US grid evolution than does EIA's APA analysis, and was done to alert investors. The chart below summarizes DBCCA's views, suggesting that CCS for gas is viable past 2030 and cheaper (and deployed earlier) for coal.

DBCCA Electricity Supply Mix Forecast

US Electricity Supply (% total kWh)	2005A	2009A	2020E	2030E	Comment
Coal traditional	50%	47%	34%	21%	Reduced to meet emissions target and comply with EPA regulation
Coal CCS	0%	0%	0%	1%	Limited deployment 2020-2030 with government R&D support
Natural gas	19%	23%	30%	35%	Coal to gas fuel switch, underutilized assets, strong new build
Natural gas CCS	0%	0%	0%	0%	No deployment, assume that gas CCS is viable post 2030 and cheaper $/MWh than coal
Petroleum	3%	0%	0%	0%	No additions, existing capital stock remains for reliability but hardly used
Nuclear	19%	20%	21%	23%	Modest gains from nuclear steam generation "uprates" and limited new builds
Wind and solar (intermittent)	0%	2%	9%	14%	Large capacity additions; transmission and dispatchability limit growth vs potential
Baseload renewables (geothermal & hydro)	7%	6%	6%	6%	Share decreases modestly as only very limited new builds
Total	100%	100%	100%	100%	
Renewables share total (intermittent and baseload)	9%	10%	15%	20%	Doubling of share 2010 to 2030 due to wind and solar additions to meet RPS
Electricity Demand (kWh)	4,055	3,784	3,978	4,181	0.5% CAGR growth due to energy efficiency and operational improvements
CO2 emissions (mn metric tons)	2,397	2,200	1,691	1,347	Emissions reduced substantially due to the coal to gas fuel switch and build-up in renewables
% CO2 emissions reduction vs. 2005		-8%	-29%	-44%	

Source: EM, DBCCA analysis 2010. See page 14 for further discussion

The State of California has strong legislation in place to regulate GHGs. Several other states have adopted companion legislation, and the Regional Greenhouse Gas Initiative (RGGI, includes nine Northeast and Mid-Atlantic states with New Jersey's recent withdrawal) has been underway since 2008. California has convened a substantial review of CCS, even though CA has the least regional CI from powerplants in the US, while the Midwest Governor's Association, along with the Great Plains Institute, has underway a carbon capture and EOR initiative (20).

Although the 112th Congress has no appetite for climate legislation, EPA, acting under Federal court orders, is on its way toward requiring a national inventory in preparation to regulate GHGs through the Clean Air Act. Powerplants will be early targets. Meanwhile, EPA is preparing to more stringently regulate coal plants (an excellent summary is at (8)). Many analyses have shown that gas is a cheap, far cleaner and more abundant fuel for replacing coal, notably the DBCCA analysis cited above (6).

Conclusions Almost no strategic analysis has been done in the US that focuses on the need and timing for CCS from gas generation, and the DoE's budget planning shows little evidence of such (7, 23). The National Energy Technology Laboratory (NETL) has underway three significant commercial demonstration projects, three with postcombustion capture from coal plants (AEP, NRG and Basin Electric Power Cooperative), and one (Air Products and Chemicals) where two large steam methane reforming plants produce merchant hydrogen for petroleum refining. In none of these is CO2 being captured from gas turbine combustion, but key inferences could be made from similarities between coal and gas post capture.

Scouting through contemporary analyses that do mention CCS for the gas fleet, we see that under substantial GHG regulation (EIA/APA (3)), CCS for gas might be needed in new plants deployed during 2016-2020, with 9% of electricity provided to the grid needed to come from gas with CCS by 2035. EPA's analysis of the APA shows similar results, especially under the influence of bonus allowances for CCS. Driven not by Federal GHG regulation, and without a fully marketized cost of carbon, but a combination of state Renewable Electricity Standards and new EPA regulations from the Clean Air Act, DBCCA's analysis (6) shows that a combination of regulatory and market forces will make CCS for gas competitive by 2030. California's recent comprehensive review of CCS suggests (10) that it might be needed before 2030.

Nearly all R&D work on CCS since the mid-1970s has been devoted to coal, since it presents formidable technical and economic problems, and has encouraged the Federal government to invest substantial funding only in coal research, demonstration and deployment (RD&D) projects. Another factor guiding Federal RD&D strategy is that until 2008 or so with the proving up of large domestic shale gas reserves, coal was seen as the largest of the U.S. energy resources.

After capturing a CO2 stream from a fuel combustion process, compression, transportation and storage would be identical between gas and coal. Section II reviews the status of the principal technical, policy, legislative and economic aspects of CCS. A recent review by the DOE CCS program manager (7) suggests that commercial deployment for gas would be post 2030, with the early emphasis solely on coal. Funding has been uneven. DoE's CCS RD&D roadmap contains no information on CCS for gas, largely focusing on precombustion capture for coal (23).

Much state and federal legislation has been introduced over the years to incent RD&D and commercial use—technical progress has been substantial for coal, but deployment remains distant. Projected costs remain high, and CCS needs a companion market for carbon allowances to monetize salient value—without a price on carbon, slowing progress toward CCS will be slower along all aspects, including Federal RD&D, and reducing the overall emissions intensity of the grid.

The State of California has extensive legislation to regulate CO_2, and starting in 2012, the cap-and-trade program will apply to industrial sources emitting more than 25,000 metric tonnes of CO_2 equivalent per year, electricity generation and imports. It will expand in 2015 to include transportation fuels (a low carbon fuel standard, LCFS) and all commercial and residential fuel combustion of natural gas and propane.

Key Findings

- Abundant analysis shows increased demand for gas to replace coal, potentially delaying the need for CCS on coal to meet near-term emissions reduction targets but not eliminating the need for CCS to meet mid-century reduction targets.
- California will implement a cap-and-trade system that covers electricity generation and imports by 2012; CCS is an approved abatement technology.
- CCS for gas will likely need to be commercially deployed to meet state and regional targets (even without separate Federal climate legislation), before 2030. To meet this goal, large scale demonstration projects will be needed several years before.

II. CCS Status

Two major panels during 2010 comprehensively reviewed the status of CCS:

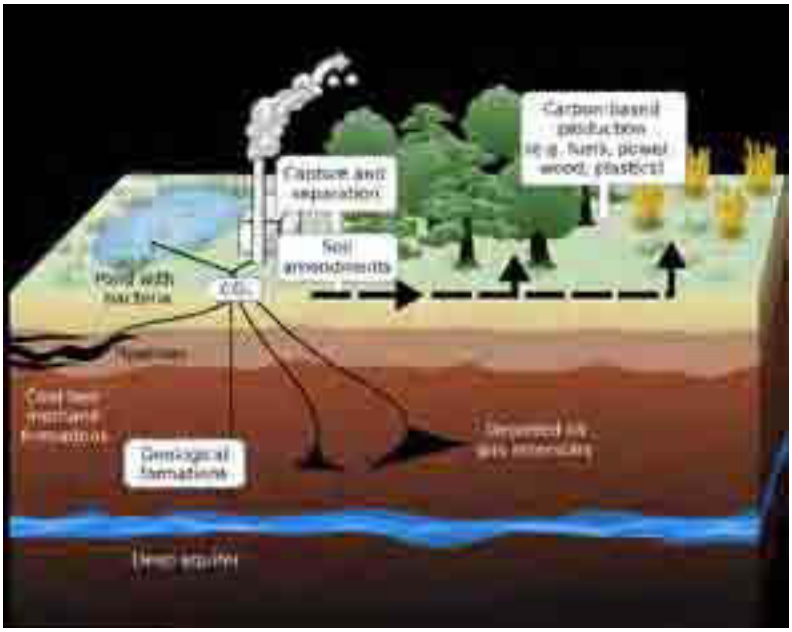
- The President's Interagency Task Force on Carbon Capture and Storage, composed of 14 Executive Departments and Federal Agencies (report in August 2010 (9)), and
- The California Carbon Capture and Storage Review (report in December 2010 (10)) overseen by the CA Energy Commission, Public Utility Commission and the Air Resources Board.

Both the USG and CA see themselves as being in a leadership role. The Federal panel describes the current status of CCS ((9),p8):

> "While there are no insurmountable technological, institutional, regulatory or other barriers that prevent CCS from playing a role in reducing GHG emissions, early CCS projects face economic challenges related to climate policy uncertainty, first-of-a-kind technology risks, and the current high cost of CCS relative to other technologies. Administration analyses of proposed climate change legislation suggest that CCS technologies will not be deployed in the next two decades absent financial incentives that supplement projected carbon prices. In addition to the challenges associated with cost, these projects will need to meet regulatory requirements that are currently under development. Long-standing regulatory programs are being adapted to meet the circumstances of CCS, but limited experience and institutional capacity at the Federal and State level may hinder implementation of CCS-specific requirements. Key legal issues, such as long-term liability and property rights, also need resolution."

CCS Technologies CCS (9) involves three steps: capture from industrial processes or power plant combustion, compression of the gases for transportation in pipelines, and storage in geologic reservoirs. Technologies and industrial practice exist for all three steps, but not near the magnitude required for the widespread GHG reductions needed for limiting climate change (9, 15). Capture has only been profitable for isolated industries for enhanced oil recovery from mature oil fields (EOR), urea production and food and beverages. Approximately 70-90% of the total cost of CCS comes from the capture phase.

CO2 can be separated and captured before combustion in an integrated gasification combined cycle (IGCC) power plant for coal (experimental, pre-combustion capture) or after combustion at a coal- or natural gas-fired power plant—through post-combustion capture where the flue gas is processed or through oxyfuel combustion where the fuel is combusted in an oxygen-rich environment and the flue gas is captured and compressed. Post combustion capture would apply primarily to retrofits with existing powerplants or newly designed CCGTs. Once CO2 is captured from a gas-fired electric generation plant and cleaned up, it is indistinguishable from that captured from a coal plant and cleaned. Hence all the compression, transportation, storage and postcapture regulatory issues are largely identical, and will not be detailed here.



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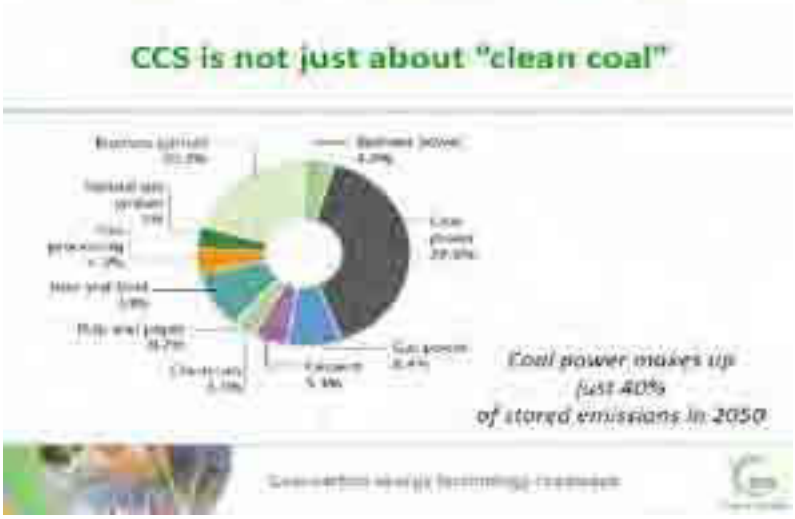
CO_2 emissions do not only originate with the energy industry, as this diagram from the IEA (12) shows:



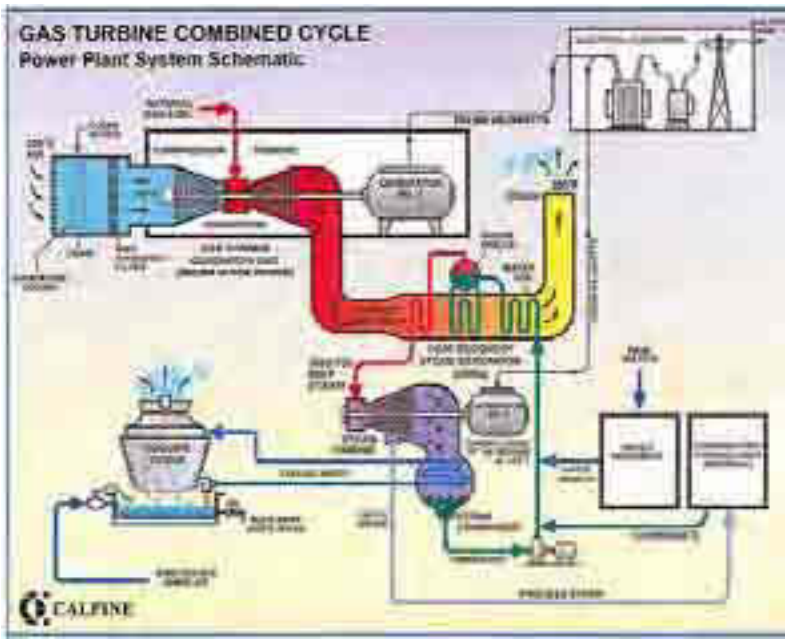
CO_2 can also be associated with production of natural gas, which could contain from none (most shale gas production has little associated CO_2) to nearly 78%, as is encountered in the LaBarge field in Wyoming, whose Shute Creek separation plant (ExxonMobil) yields some 3.6 Mt/yr, compared to a single 550 MW coal plant that might produce 5 Mt/yr. Capturing hot, corrosive combustion gases from powerplants would be significantly different than separating CO_2 from ambient temperature producing wells. One of the key technical barriers to commercial deployment is that there is, as yet, no commercial, full-scale project that integrates proven combustion capture, transport and storage technologies into a single enterprise—one of the original purposes of the FutureGen project.

Perhaps the closest is the world's largest geologic storage project—the CO_2 source is the Great Plains Synfuels plant (Dakota Gasification Project), where lignite coal is gasified and a split stream of CO_2 is piped ~ 200 miles to a large, mature oil field near Weyburn, Saskatchewan, for EOR use. Over 1.8 Mt/yr have been injected since 2000, and a substantial amount of incremental oil has been produced. This is an entirely commercial project, not simply a subsidized demonstration. These EOR miscible flood techniques—high pressure CO_2 is injected to mix with the oil to improve flow characteristics and boost recovery—have been developed in the US and used successfully for several

decades in North America. Very few such projects have been done in other countries (13).

Postcombustion capture (PCC) from flue gases prior to venting to the atmosphere is the principal method of CO2 capture applicable to CCGTs. PCC has considerable near term potential for reducing powerplant CO2 emissions and can be applied to coal, gas, or industrial sources combusting fossil fuels. When fully developed, it could potentially be retrofitted to existing plants or integrated into new designs, or designed for varying levels of CO2 capture. Designing systems for flue gases from CCGTs would be challenging—volumes are huge, of the order of 2 million cubic feet/minute for a 500MW plant, containing 6-14% by volume of CO2, and are emitted at low pressures (15-25 psia), elevated temperature (~200 degrees F) and with high oxygen content, but include no particulate matter, no sulfur dioxide, no compounds of Mercury, small amounts of N2O, little NO, some moisture and considerable nitrogen (9).

As background, the diagram below shows a typical CCGT. Notice how waste heat is recovered from hot stack gases with a smaller supplementary boiler and turbine (the combined cycle), and how steam condensate is recycled internally—which greatly adds to overall system output efficiency, a hallmark of CCGTs. Less waste heat also requires less cooling water, and a cogeneration unit could also be added to recover yet more of the lower quality heat.



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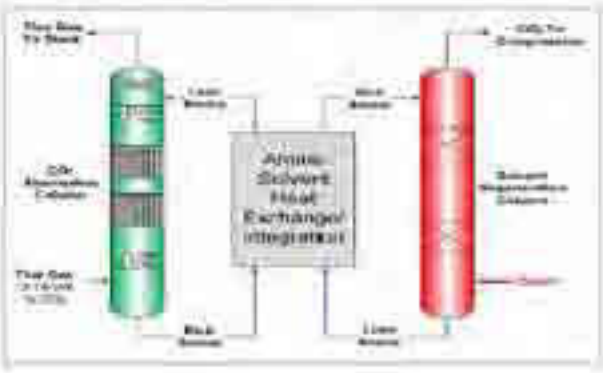
A 2009 review of commercially available CO2 capture technologies identified 17 facilities in current operation in the US (9)(11). They include four gas processing operations and a syngas production facility in which approximately 1 MT of CO2 are captured each year. The largest, Shute Creek in Wyoming (serving the LaBarge gas field), captures 3.6 MT/yr, approaching the volume needed for an electric power plant. However, capture from gas processing plants is unlike that of flue gases—chemical composition of these gases is far more varied and more corrosive, while temperatures can be considerably elevated. Compressing and transporting large volumes of CO2 would involve related techniques. Costs and operations would generally be very different.

Present PCC normally uses a solvent to capture CO2 from flue gas, which is then regenerated with steam as the CO2 is released for later compression and storage. Amine (ammonia-based) solvents are most likely to be used, and are routinely used to remove CO2 and hydrogen sulfide (H2S) from natural gas and refinery process streams. Amines would be used as first generation capture solvents, due to today's advanced state of development of amine absorption and regeneration. Chemical solvents are less dependent on partial pressures than physical solvents, and since CO2 in flue gas is typically 4-14% by volume, chemical solvents are more feasible.

Amines react with CO2 via reversible reactions to form water-soluble compounds. They require, though, more energy or steam to regenerate and release CO2 once captured from flue gases. There is a high oxygen content in CCGT flue gas, which can present problems for amine solvents. Industrial amine processes do not now operate on the scale of power plants, but upsizing is thought to be feasible. For amines to work properly, very low levels of nitrogen and sulfur need to be present in the flue gas, thus upstream scrubbing is required for coal, but not for gas (9, 11, 16) . Different designs of smaller amine systems are commercially available. Figure A-5 shows an amine-based PCC process (9).

Figure A-5. Schematic Diagram of Amine-based CO_2 Capture Process



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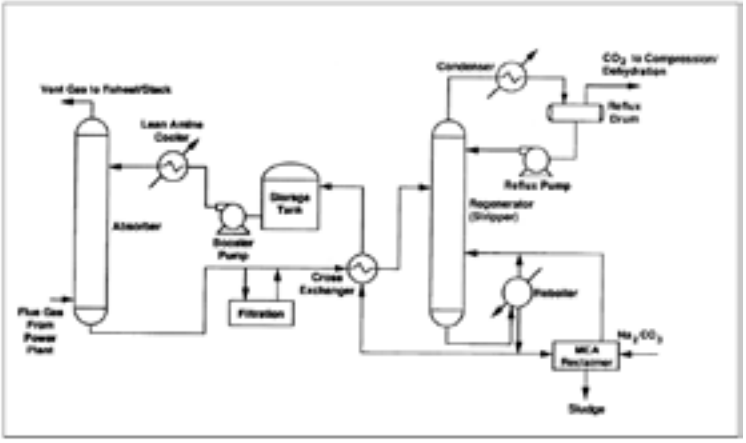

Figure 1. Process flow diagram for the amine separation process.

Another process flow diagram is Figure 1 from the report done for the Clean Air Task Force, "Advanced Post-Combustion CO2 Capture" (11). A concentrated stream of CO2 is extracted from the combustion gas, and larger amounts of water and steam are required, increasing the levelized cost of electricity from modern and advanced coal plants in early designs, for instance, by up to ~80%, accompanied by up to a 30% energy penalty to regenerate the solvent to release the CO2 and compress it for transportation and storage. Siemens, in their latest design and testing for the Statkraft project (below), however, foresees little compromise in plant performance (16). Considerable RD&D at DoE and in the industry is focused on reducing these costs and energy penalties—estimated to be a 7.4% loss for NGCCs by NETL ((20)—p6).

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Table A-3. Key Technical Challenges for CO_2 Capture

Parameter	Technical Challenge
Scale-Up	[illegible]
Cycle Efficiency	[illegible]
Auxiliary Power	[illegible]
Energy Efficiency	[illegible]
Energy Integration	[illegible]
Flue Gas Contaminants	[illegible]
Water Use	[illegible]
CO_2 Compression	[illegible]
Oxygen Supply	[illegible]

Table A-3 highlights key technical challenges. A more thorough review of PCC technology in the U.S. is in references (11) and (20).

A notable now underway on developing PCC for CCGTs is being carried out with the Norwegian utility Statkraft (16), partnered with Siemens for the European Union, to be completed in 2011 (this work has now slowed due to funding challenges). The flue gas from a CCGT has a lower CO2 concentration than for a corresponding coal plant, but it has a higher oxygen content—which could lead to more degradation for known solvents.

Statkraft, as an owner of both wind and gas, are also optimizing flexibility methods for handling frequent changes in load due to greater integration with VERS. Statkraft intends to be a leader in clean electricity generation for the European energy market, investigating new plant designs that can be efficiently retrofitted in compliance with upcoming EU emissions requirements. It is expected that within a decade, the EU will

be supporting large scale commercial demonstrations of PCC ((17)—a now outdated review, as funding has changed).

Improving key solvent performance parameters and efficiency while reducing costs will be key elements of commercializing CCS for gas plants. Other, bench and pilot scale CO2 capture methods are being developed with industry, including regenerable sorbents for dry carbonate scrubbing and novel molecular separation membranes made of various materials.

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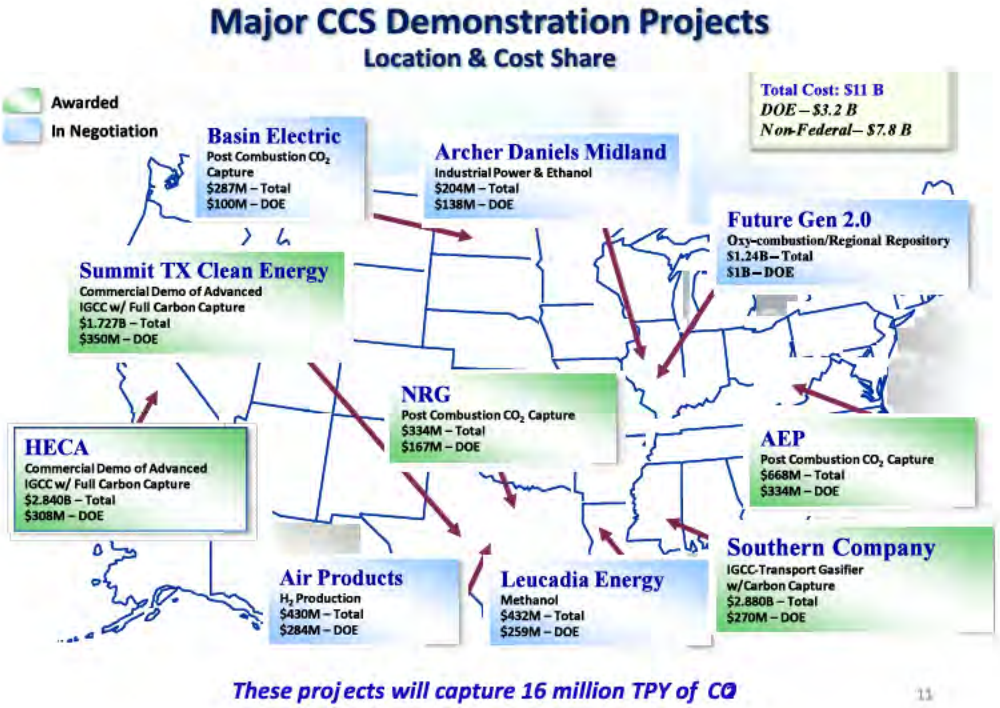
Demonstrations A critical step in developing proven CCS is demonstrations done at a significant scale, particularly for capturing and storing CO2 from flue gases. These have been rare in the US until 2008-9. In the original DoE plans, the closest analogues for CCGT application were the PCC demos by Basin Electric Power Cooperative with lignite coal in North Dakota and the AEP project in West Virginia with bituminous coal (which are now cancelled—see Herzog and Curry papers from the CCS Forum) plus the Air Products Port Arthur, TX, plant which uses steam methane reforming to produce hydrogen from natural gas for refining crude oil (14).

The AP&C project will demonstrate a newly designed retrofit system to concentrate a stream of pure CO2 for storage in an EOR project. Funding comes from a cost share with DoE under the American Recovery and Reinvestment Act of 2009, to be completed in 2015. About 1 Mt/yr of CO2 will be captured, resulting in recovery of about 1.6-3.1 Mb of domestic oil.



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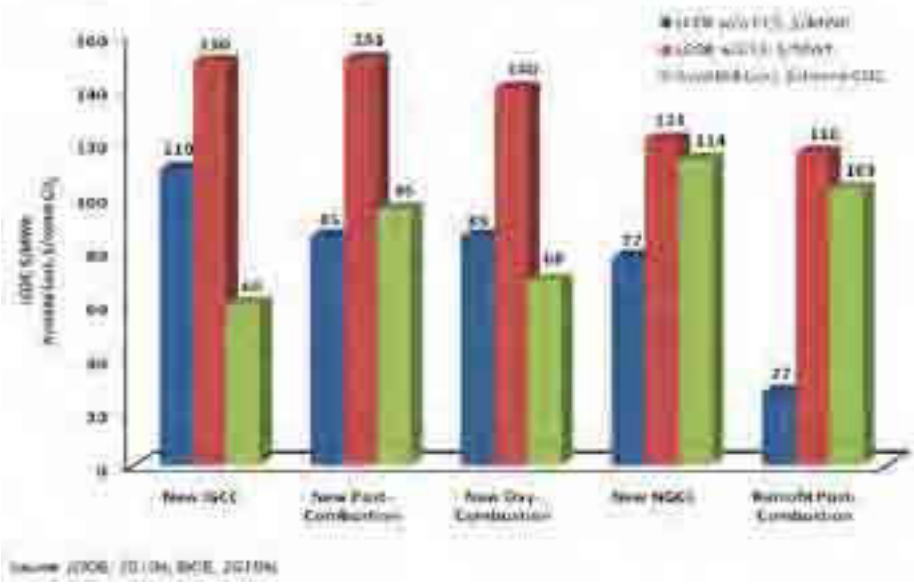
Costs Figure A-9 (9) compares the levelized cost of electricity (LCOE, (18)) from a variety of simulated 550 MWe plants with and without CCS. New NGCC plants would be somewhat cheaper than any of the coal plant options, and NGCC retrofit would likely be cheaper than retrofits for coal plants.

A new IGCC (Integrated Gasification Combined Cycle) coal plant would cost $400 M more by adding CCS, and incur an energy penalty of about 20%. For a NGCC plant with PCC, the capex would increase by $340 million, with an energy penalty of 15%. Note that the cost of CO2 avoided is highest for NGCCs, at $114/tonne. More recent work estimates this as $84/tonne (17). The Stakraft/Siemens project goals were to show somewhat lower costs and higher efficiency.

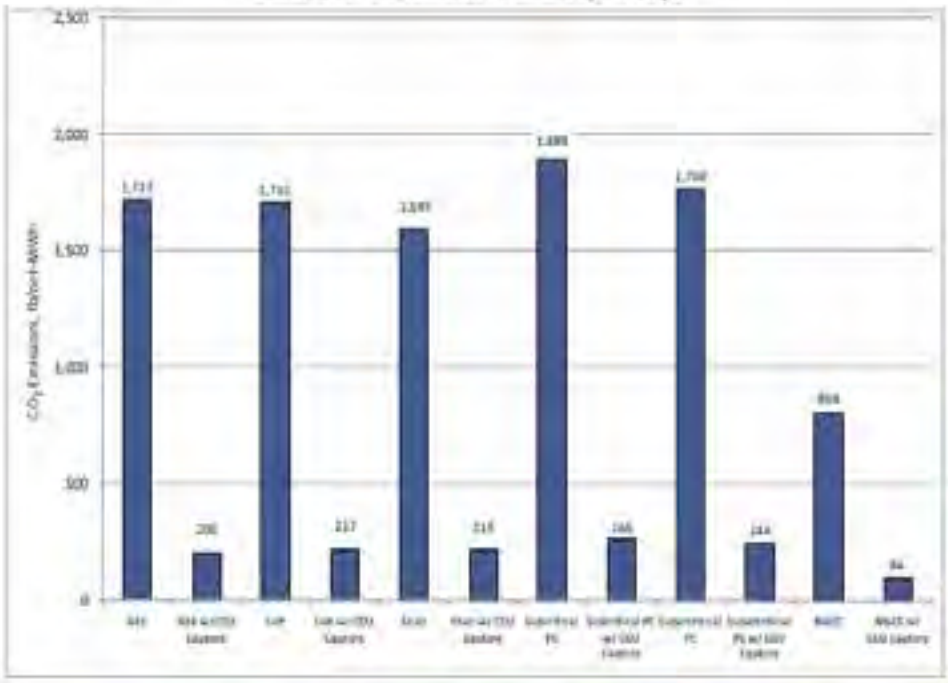
The International Energy Agency (12) has reviewed many analyses for cost comparisons of PCC with amines, including largely US sources plus Europe and China. Average U.S. and EU plant size was 545 MW, net efficiency with capture 30.9%, CO2 emissions 111 kg/MWh, and LCOE $107/MWh. Relative increase in LCOE with capture was 63%.

Figure A-9. Comparison of Levelized Cost of Electricity for Different Types and Configurations of Power Plants



Relative emissions ES-17 (20) compares simulated CO2 emissions from different advanced designs of coal plants, and an NGCC, whose CO2 emissions with capture are far less—only about 35%-46% of the best coal plants. ES-15 shows just how remarkably cleaner, with-or-without CO2 capture, the same NGCC is with respect to criteria emissions compared to the best coal plant designs—slight amounts of NOx, no SO2 and no particulates. All have been normalized for the same electric power output.

Exhibit ES-17 CO_2 Emissions Normalized By Net Output



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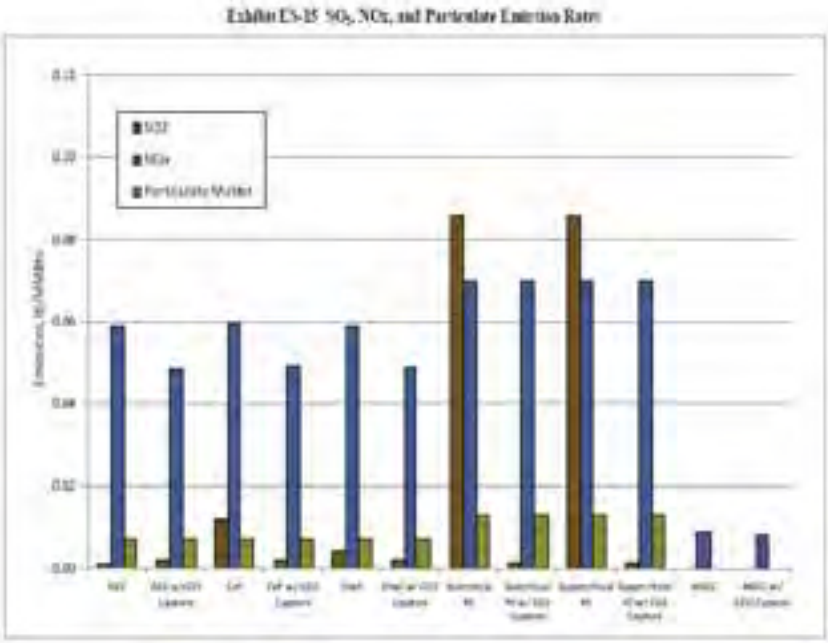


California Carbon Capture and Storage Review Panel The Panel (8) was established by the California Public Utilities Commission, Energy Commission and Air Resources Board (CARB) in February 2010. Unlike the Federal Interagency Task Force, it was composed of industry, trade groups, academia and NGO experts. The final report was published December 31, 2010. Their main purpose was to explore the need for a clear State policy and regulatory framework, besides issues addressed by the US EPA, which in November 2010 released new regulations under Underground Injection Control (UIC) for CO2 injected into subsurface formations for storage, as well as a subpart to the GHG Reporting Rule for annual reporting from geologic storage projects.

In December 2010, CARB approved cap-and-trade rules that plan to incorporate CCS as a technology that is eligible to meet GHG emissions reductions. Beginning in 2012, the cap-and-trade program will apply to industrial sources emitting more than 25,000 tonnes of CO2 equivalent /yr, electricity generation and imports. It will expand in 2015 to include transportation fuels (a low carbon fuel standard, LCFS) and all commercial and residential fuel combustion of natural gas and propane. An allowance price for CO2 in 2020 is expected to be about $21/tonne. California's electricity sector is primarily supplied by in-state NGCCs, with 20% coming from coal imports. Referring to Figure 3 under the section above on Regional Carbon Intensity (5), note that California's generating fleet already has the lowest carbon intensity (CI) of any Census Region of the US: 195.6 kg-CO2/MWh, only 1/3 of the US average at 583 kg-CO2/MWh—due

primarily to hydro, renewables, gas and only 3% coal in the grid mix. In addition to a summary technical review, they have concentrated on a wide variety of regulatory issues.

CO2 Storage A variety of geologic formations are being assessed as potential target formations for injecting and storing CO2 in North America, including deep saline formations, depleted oil and gas reservoirs, unmineable coal seams, and other formations.

DoE has created a network of seven Regional Carbon Sequestration Partnerships (RCSPs) to help develop the technology, infrastructure and regulations to implement large scale CO2 storage in different regions and geologic formations in the US and neighboring Provinces of Canada (19, 22). Organized in 2003 with wide stakeholder membership, they have collectively produced the *"2010 Carbon Sequestration Atlas of the U.S. and Canada"* (3rd Edition, November 2010) (26).

DoE and its many partners have concluded that saline formations clearly offer the greatest potential storage resource and capacity. However, many of the first geologic storage projects will likely be in oil and gas reservoirs, since the geology of these sites has been previously characterized, the techniques are very well developed, and they have existing infrastructure to support injection activities—enhanced oil recovery (EOR) using CO2 as a working fluid could produce substantial new volumes of domestic oil.

> *Deep saline formations:* These formations are sedimentary rock layers that are generally more than 800 meters deep and are saturated with brines that have a high total dissolved solids (TDS) content (i.e., over 10,000 mg/L TDS). Deep saline formations are found throughout the United States, many overlain by laterally extensive, impermeable formations that may restrict upward movement of injected CO2, hence sealing them into very long term storage.
>
> *Depleted oil and gas reservoirs:* since many of these reservoirs have trapped liquid and gaseous hydrocarbon resources for millions of years, it is believed that they can also be used to store CO2. Much depleted, empty reservoir space exists from many decades of oil and gas production. Hydrocarbons are commonly trapped structurally, by faulted, folded, or fractured formations, or stratigraphically, in porous formations bounded by impermeable rock formations. These same trapping mechanisms can effectively store CO2 for geologic storage in depleted oil and gas reservoirs.
>
> *Unmineable coal seams:* Currently, enhanced coal bed methane (ECBM) operations can use injected CO2 to effectively replace methane, as it is adsorbed on the coal surface, then releases the methane, which is then captured and commercially produced. Studies suggest that for every molecule of methane

displaced in ECBM operations, three to thirteen CO_2 molecules are adsorbed. This process effectively "locks" the CO_2 to the coal, where it remains stored.

Federal, state, industry and academic RD&D continues on evaluating performance of a wide variety of storage media.

Large scale storage projects

The Sleipner project, begun in 1996 in Norway, is the longest-running commercial-scale CO_2 storage project in the world—injecting 98 percent pure CO_2 separated from produced natural gas in order to avoid paying a carbon tax to vent the CO_2, imposed by the Norwegian government. It injects one million tonnes of CO_2 annually through one horizontal well into the 250m thick Utsira Sand, a high permeability, high porosity sandstone unit roughly 1,100m below the sea surface. The reservoir is sealed with shales, and mudstones and shale baffles (discontinuous shale lenses) are present in the reservoir to further limit upward movement of CO_2. Based on its unique properties, the Utsira Sand is considered a good analogue for an optimal storage reservoir.

The Weyburn project is a combined EOR/geologic storage project operated by EnCana in southern Saskatchewan near the North Dakota Border. The project began in 2000 and uses a mix of 29 horizontal and vertical wells to annually inject roughly 1.8 million tonnes of 96 percent pure supercritical CO_2 from a lignite gasification plant (see above), into two adjacent carbonate layers. Commercially profitable CO_2-EOR operations at Weyburn demonstrate the use of EOR/GS technology in thin, less-than-ideal formations at moderate depths.

The Snøhvit project in the Barents Sea began operation in 2010. Natural gas produced from the Snøhvit Field contains ~5 vol% CO_2. After processing, the CO_2 is returned near the site of production via pipeline and injected through a dedicated well 2,600 meters beneath the seabed at the edge of the reservoir in the Tubåsen sandstone formation, located below the producing formations. The project is expected to store approximately 0.7 million tonnes of CO_2 each year.

In Salah is a commercial-scale CO_2 storage project located in the Sahara Desert in Southern Algeria, using three horizontal wells to annually inject roughly 1.2 million tonnes of supercritical 98 percent pure CO_2 separated from produced natural gas. The reservoir is a 1,800m deep, 21m thick, low-porosity, low-permeability laterally heterogeneous muddy sandstone. Successful utilization of this reservoir relied on measurement-while-drilling techniques, which were able to target higher quality regions of the formation in real time as the wells were drilled. This project demonstrated that reservoirs previously thought marginal or unusable could successfully store commercial scale quantities of CO_2.

Other non-commercial scale test projects are underway—Ketzin (Germany), Lacq (France), Otway (Australia), Gorgon (Australia), KB12 (Netherlands), and Nagaoka (Japan) either have already been completed, are underway, or are anticipated to commence injection in the next five years. These and other projects have committed to store an additional eight million tonnes of CO2 and report on which methods for transport, purification, injection, monitoring, and other parameters were successful in the diverse environments these projects reflect.

EPA and DoE tracking of storage projects As of May 2010, 56 active storage or integrated capture and storage projects are planned or underway, located across the the US in 22 States and the Navajo Nation. Eighteen of these States and the Navajo Nation have Underground Injection Control program primacy for at least one class of injection well (EPA directly implements the program in the other four States). Ten of these States are in the process of developing regulations to address liability and/or property rights.

- 55 percent of the active storage projects plan to inject over one million tonnes of CO2 total.
- The RCSP Phase II storage projects that are complete as of 2009 have collectively injected a total of 1.45 million tonnes of CO2. This includes 63,790 tonnes injected into saline formations; 1,369,500 tonnes for EOR projects; and 17,700 tonnes into coal.
- 41 storage projects have been funded by the U.S. government through cooperative agreements, of which 12 are complete. The total cost of these projects was nearly $8.6 billion (w/industry cost share).
- 51 percent are EOR/EGR projects. The remaining are saline (37 percent), EOR/saline (6 percent), and Enhanced Coalbed Methane (ECBM) (6 percent).
- The storage projects involve injecting into several different depositional classes of geologic formations (e.g., basalts, carbonates, clastic rocks, and coal) to assess issues with injectivity, capacity, and containment associated with the varied geology across the U.S.

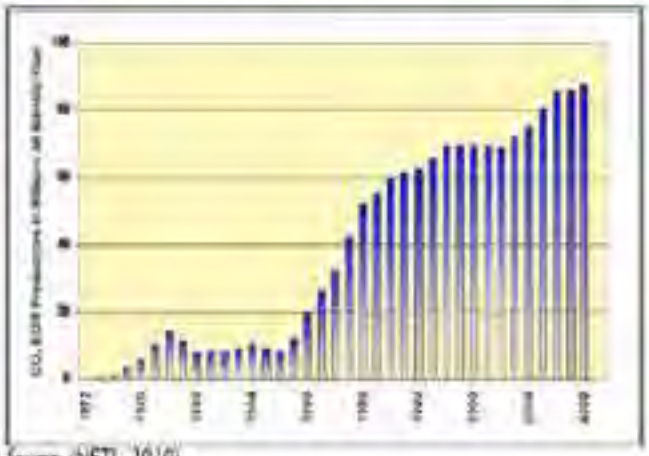
Other pathways to identifying geologic storage opportunities are noted in: "*Impact of the Marcellus Shale Gas Play on Current and Future CCS Activities"* NETL (August 2010)(23).

EOR It is estimated that about 2/3 of all US oil resources are effectively stranded, as conventional production techniques have been unable to produce all of them. Over the years, many innovative methods have been devised to solve these problems, and more will be developed as oil prices appear to stabilize in the $80-$100/b range. Some of the more sophisticated enhanced oil recovery (EOR) techniques utilize CO2 as a working fluid to artificially increase reservoir pressure, decrease viscosity and surface tension of petroleum trapped in pore spaces that have been bypassed by conventional production, thereby enhancing mobility and flow. CO2 floods can be used in combination with water or steam, depending on profitability, geology and development style.

Mature and partially abandoned oil fields can enjoy substantial new, incremental increases of production from the original oil in place of 15%-30%, where conventional development might have recovered only 20-35%. CO2 is a common and very effective working fluid for EOR in the right geologic applications. Although expensive, and needing substantial nearby supplies of CO2 at reasonable prices, some EOR projects were profitable when oil reached even $15-20/b. CO2 purchase and transport can make up 33%-68% of project costs, so it is carefully managed (9). It is separated at the surface from the oil, recovered and recycled as the CO2 floods are maintained, with some amounts retained within the reservoirs.

As of 2008, there were 105 active CO2 EOR active projects in the US. More will become feasible as oil prices rise. The majority (58) are in Texas, but others are located in MS, WY, MI, OK, NM, UT, KS, CO and ND. Nearly 79% of the CO2 is from associated methane production, and 21% from industrial sources.

Figure D-1. Growth of U.S. Oil Production from CO_2-based EOR



Source: (NETL 2010)

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CO_2-EOR projects recovered 323,000 barrels of oil per day in 2008, which was 6.5% of total domestic oil production. A total of 6,121 CO_2 injection wells among 114 projects were used to inject approximately 50 million tonnes of CO_2 (7).

As an innovative CO_2 mitigation initiative, an intergovernmental/NGO EOR project is being formed now between the Midwestern Governor's Association (MGA), the Great Plains Institute (GPI), the Pew Center on Climate Change and the US Energy Association. Some Midwest utilities and an EOR developer, as well as an oil and gas producer and private foundations will be participating, along with some state legislators and interested Members of Congress. A scoping study done for the MGA shows considerable commercial capture and storage opportunity for EOR in the Midwestern states (21). The GPI is convening a group of expert stakeholders to evolve state and Federal policies to enable CCS for a variety of power sources (including gas), and facilitate promising technology demonstrations and commercial projects.

Monitoring, verification, and accounting MVA are key components of managing a geologic storage project and ensuring that the injected CO_2 plume and associated pressure front are moving through the subsurface as predicted. Baseline monitoring data are necessary to differentiate natural phenomena from signals associated with storage. Data collected during site characterization (such as baseline geochemistry, pre-injection reservoir pressure, etc.) are necessary to ensure that baseline information is available to form the basis for operational comparisons.

For example, the baseline geochemical information will allow the owner or operator and permitting authority to evaluate monitoring data and identify any changes in subsurface geochemistry that may indicate fluid movement. Operational-phase monitoring can demonstrate that a geologic storage project is performing as predicted, or provide warning that unexpected fluid movement has occurred or adverse impacts associated with leakage of stored CO_2 may occur.

Appropriate monitoring of a geologic storage site can also provide data to maintain the efficiency of the storage operation, minimize costs, improve site modeling, and target needed future corrective action. Robust MVA is also needed to ensure the integrity of CO_2 storage as a mitigation strategy under a carbon-constrained regulatory regime.

Regulatory and policy challenges Both the US Interagency Task Force and the California Carbon Capture and Storage Review Panel have extensively reviewed the many regulatory issues surrounding storage facility maintenance, ownership, monitoring, liability, long term stewardship and environmental justice. Rather than detail these here, a list of barriers and concerns might be illustrative (9)(10):

- Regulatory framework governing the capture, transportation, and storage of CO_2
- Long-Term liability regarding storage of CO_2

- Public information, education, and outreach
  - Elements of a successful outreach strategy
- Framework for addressing market failures
- Framework for incentivizing CCS technology as public investments for public gain
- Failure to account for social cost of GHG emissions
- Public funds require adaptive resource management
- Technology-push drivers for CCS
- International collaboration
- Market-pull incentives for CCS
- Loan guarantees, direct loans and grants
- Tax treatment and incentives
- Federal budget scoring for tax and RD&D policies
- GHG "bonus" allowance allocation
- Approaches for legal or regulatory structures to deal with potential liabilities
- Substantive or procedural limitations on claims
- Liability fund
- Government ownership or direct liability
- Governmental indemnification
- Transfer of liability to the Federal government after site closure and governmental certification
- Options for Federal action on public outreach and education
- Pipeline transport and safety
- Applicability of selected environmental laws to the storage phase of CCS
- Applicability of the National Environmental Policy Act, the Endangered Species Act, and the National Historic Preservation Act to CCS activities
- Potential causes of long-term storage risk and/or liability
- Price Anderson Act private insurance program
- Liability associated with DOE CCS RD&D programs
- Surface and subsurface property rights
- Siting considerations for CO2 pipelines.

S. 699 Some of these issues are being addressed in various states, and in some Federal legislation (9). Action is incomplete, but would be accelerated if regulatory legislation proceeded. California is prepared to make very large strides in this arena, and has many of the needed authorities in place. A new bipartisan CCS RD&D bill has been passed by the Senate Committee on Energy and Natural Resources, S.699, the *DOE CCS Program Amendments Act of 2011*, which is intended to fund up to 10 commercial scale CCS projects. It would create more certainty for early mover project developers, including liability, financing, safety, and a framework for long-term assurance for geologic storage sites. It includes CCS for both coal and natural gas, and should be discussed in our forum.

End Notes

1) "Task Force on Ensuring Stable Natural Gas Markets", Bipartisan Policy Center and American Clean Skies Foundation (March 2011) http://www.cleanskies.org/wp-content/uploads/2011/05/63704_BPC_web.pdf

2) http://www.dbcca.com/dbcca/EN/_media/NaturalGasAndRenewables-Oct_2011_Update.pdf
http://www.dbcca.com/dbcca/EN/_media/DB_Repowering_America_Creating_Jobs.pdf

3) http://tonto.eia.doe.gov/oiaf/servicerpt/kgl/pdf/sroiaf%282010%2901.pdf
The **High Natural Gas Case** assumes a larger role for shale gas, based on a High Shale Gas case in the Annual Energy Outlook 2010. The supply curve is enhanced by effectively doubling production and expanding the resource base.

The **No International Case** is an extreme, where international carbon offsets are eliminated. New technologies are affordable and widely deployed, including renewables, advanced nukes and CCGTs w/CCS. The relative rate at which coal plants are replaced with renewables, gas and nuclear is somewhat biased by heavy subsidies for coal in the APA in the early years to develop and deploy CCS, while substantial subsidies for nuclear power assist its ascendancy. "*EPA Analysis of the American Power Act in the 111th Congress*", 6/14/10. A less useful analysis, since its initial assumptions heavily disfavor gas:
http://www.epa.gov/climatechange/economics/pdfs/EPA_APA_Analysis_6-14-10.pdf

4) http://web.mit.edu/mitei/research/studies/natural-gas-2011.shtml
Remembering that MIT only reduces CO2 by 50% by 2050, vs APA's 83% by 2050—and that EIA only simulated impacts out to 2035, the prices driving all this change are substantial: EIA CO2—$122/t (2035), MIT—$240/t (2050). Gas prices rise from EIA—$14.42/mcf, MIT—$22.80/mcf. Electricity prices rise from EIA—14.46 cents/kWh (2035), MIT—26 cents/kWh (2050).

5) http://www.cleanskies.org/pdf/ACSF_Comments_on_Full_Fuel_Cycle_filing_10_29_10.pdf

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6) http://www.dbcca.com/dbcca/EN/_media/NaturalGasAndRenewables.pdf

7) "US Energy Framework and the DOE Fossil Energy Program for Carbon Capture and Storage", Victor Der, Acting Assistant Secretary for Fossil Energy (March 2011). This presentation shows no specific planning for CCGT CCS, and no powerplant demonstrations. Three post combustion coal flue gas CCS demonstration projects are underway, in North Dakota, Texas and West Virginia. Another related project technically is a cost share with Air Products and Chemicals to demonstrate CO2 capture and storage from a large steam methane reforming plant producing merchant hydrogen for petroleum refining in Port Arthur, TX. Costs are $430 M ($284 M DoE), beginning in late 2009 with completion in 2015. A concentrated stream of CO2 will be captured and cleaned for resale in EOR use. http://www.netl.doe.gov/publications/factsheets/project/FE0002381.pdf

This is funded through the American Recovery and Reinvestment Act of 2009, but the Fiscal Year 2012 Federal Budget Request "...does not provide any demonstration funds because these projects are already strongly supported through the 2009...(ARRA)". http://www.energy.umd.edu/documents/US-DOE-FE-CCS-Program-Update-VDER3-11-11.ppt

8) "Growing the Market for Clean Power: The EPA's New Power Plant Regulations and What They Mean for Utilities and Public Health", ACSF (December 16, 2010) http://www.cleanskies.org/pdf/12-20AG_MEF.pdf

9) "Report of the Interagency Task Force on Carbon Capture and Storage"(August 2010) http://www.fe.doe.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf

10) "Background Reports for the California Carbon Capture and Storage Review Panel", California Institute for Energy and the Environment (12/31/2010)

11) "Advanced Post-Combustion CO2 Capture" prepared for the Clean Air Task Force; Herzog, Meldon and Hatton (April 2009)

12) "Cost and Performance of Carbon Dioxide Capture from Power Generation" (March 2011), IEA Working Paper

13) One of the first international uses of U.S. EOR technology was in Croatia in 2002. The author participated in facilitating an economic and engineering feasibility study for a miscible CO2 flood in Croatia's mature oil fields, funded by the U.S. Trade and Development Agency for the upstream division of Croatia's national oil company, INA/Naftaplin.

14) "Air Products and Chemicals Demonstration of CO2 Capture and Sequestration of Steam Methane Reforming Process Gas Used for Large-Scale Hydrogen Production", National Energy Technology Laboratory (October 2010)
http://www.netl.doe.gov/publications/factsheets/project/FE0002381.pdf

15) During consideration of the various pieces of legislation merged into what eventually was negotiated and passed into law as the Energy Policy Act of 2005 (Public Law (109-58)), a briefing on the rise of CCS and other advanced technologies in the US, and their economic development potential through exports, one presenter observed that energy R&D spending by industry in the US was far behind that devoted to getting Rogaine and Viagra to market. Many of the beneficiaries were in the room.

16) "Carbon Capture Readiness for CCGTs", Siemens (Michael Rolls, May 18, 2010). Statkraft CCGT CCS project for the EU.
http://www.energy.siemens.com/co/pool/hq/energy-topics/living-energy/downloads/CSS_Capturing_Carbon.pdf

17) "Capturing CO2", Greenhouse Gas R&D Programme, International Energy Agency (May 2007)
http://www.ieaghg.org/docs/general_publications/cocapture.pdf

18) LCOE—present value of capex and opex over financial life, converted to equal annual payments and amortized over the expected annual generation from an assumed duty cycle

19) "An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009", J. Dooley, US DoE, Pacific Northwest National Laboratory (2009)

20) "Cost and Performance Baseline for Fossil Energy Plants", National Energy Technology Laboratory, Revision 2 (November 2010); pp i-25, 443-532

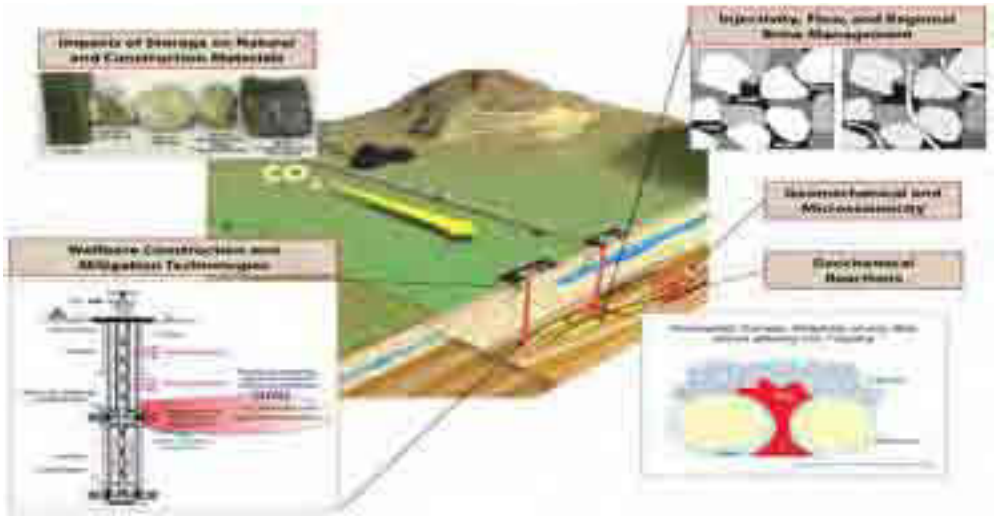
21) "Legal and Regulatory Inventory for Carbon Capture and Storage & Analogues", Midwestern Governor's Association (March 2009);

http://www.midwesterngovernors.org/CCS.htm "Case Studies of State Regulatory Treatment of Carbon Dioxide (CO2) Injection and Other Analogs", World Resources Institute (WRI); "CO2-Enhanced Oil Recovery Potential for the MGA Region", Advanced Resources International (June 2009); "U.S. Oil Production Potential from Accelerated Deployment of Carbon Capture and Storage", Advanced Resources International (March 2010); "Safeguarding American Energy Security and Jobs: A National Initiative to Scale Up Domestic CO2 Enhanced Oil Recovery", Great Plains Institute (February 2011) http://www.gpisd.net/index.asp?Type=B_BASIC&SEC={79D854EA-461D-49F6-89F6-4ACD6E2F955A}

22) http://fossil.energy.gov/sequestration/partnerships/index.html

23) "Impact of the Marcellus Shale Gas Play on Current and Future CCS Activities", NETL (August 2010)

24) http://www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf



25) http://www.netl.doe.gov/technologies/carbon_seq/refshelf/CCSRoadmap.pdf

26) http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII/index.html

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The Climate Impact Of
Natural Gas and Coal-Fired Electricity:
A Review of Fuel Chain Emissions Based on Updated EPA
National Inventory Data

By
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April 19, 2011

The Climate Impact Of Natural Gas and Coal-Fired Electricity: A Review of Fuel Chain Emissions Based on Updated EPA National Inventory Data

By
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and
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Abstract:

This paper provides an updated, comparative fuel chain calculation of the greenhouse gas (GHG) emissions of natural gas- and coal-fired electricity. The analysis incorporates revised 2011 US EPA estimates of fugitive methane emissions from the upstream (i.e., production) portion of the fuel chain. Based on this revised EPA data and average generation heat rates, we find that *existing gas-fired generation is still, on average, about 51% less GHG intensive than existing coal-fired generation*. Similarly, a new gas-fired combined-cycle unit produces about 52% less GHG emissions per kWh than a new coal-fired steam unit; about 58% less than the average coal-fired unit; and about 63% less than a typical older coal-fired unit.

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Introduction

Valid comparisons of the greenhouse gas (GHG) emissions associated with the fuels used for electric generation require comparing emissions from the full fuel chain; that is, from production to combustion, including fuel processing and transportation. This paper focuses on new data for the fuel chain emissions associated with natural gas-fired electricity and compares these emissions with the fuel cycle emissions for coal-fired generation.[3]

The fuel chain for natural gas includes several sources of GHG emissions. These emissions include CO2, N2O, and methane (CH4), which should be calculated taking into account the different atmospheric lifetimes and radiative forcing power of the gases.[4] Methane emissions from natural gas production and transport to market are the most important of the upstream emissions, due to the quantity of emissions and the fact that methane is a more powerful greenhouse gas than CO2. Coal mining also releases methane and that must be accounted for in a consistent way as well.

Recently, the US Environmental Protection Agency (EPA) revised its estimates of methane emissions from natural gas production, significantly raising estimates, particularly regarding emissions from field production (i.e., drilling sites). Specifically, in the most recent national GHG inventory,[5] and in a related EPA report on GHG

[3] ACSF has previously supported the Department of Energy's proposal to incorporate full-fuel-cycle (FFC) measures into energy efficiency standards for gas and electric appliances. These standards would also provide a new basis for evaluating the comparative GHG impacts of different appliances. The DOE's Notice of Proposed Rulemaking, and Final Rule can be found at: http://www.eere.energy.gov/buildings/appliance_standards/certification_enforcement.html. ACSF's comments are available at: http://www.cleanskies.org/pdf/ACSF_Comments_on_Full_Fuel_Cycle_filing_10_29_10.pdf.

[4] We compare the effect of different GHGs using the 100-year global warming potential ratios from the most recent Intergovernmental Panel on Climate Change (IPCC) report, *IPCC Fourth Assessment Report: Climate Change* (2007), http://www.ipcc.ch/publications_and_data/publications_and_data_reports.shtml. The global warming potential (GWP) is the ratio of the total radiant forcing of a GHG, based on its atmospheric lifetime and radiative forcing power, compared to that of CO2, over a specified time horizon. The 100-year horizon is used most commonly, and the 100-year GWP values from the Second IPCC assessment (in 1995) are codified in the Kyoto Protocol to the UN Framework Convention on Climate Change and used in national inventory accounting, including that of the US EPA cited here.

[5] U.S. EPA, *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2009* (2011), EPA-430-R-11-005, http://www.epa.gov/climatechange/emissions/usinventoryreport.html.

reporting in the oil and gas industries,[6] the EPA applied a modified methodology for estimating some sources of fugitive methane emissions from upstream production. The EPA increased estimated emissions from "gas well cleanups" by more than 20 times; it also added emissions due to "unconventional gas well completions and workovers involving hydraulic fracturing," which is used to extract natural gas from shale gas deposits.

As a result, the 2009 inventory (and the revised 2008 inventory) shows natural gas upstream emissions as about 23% of combustion emissions, which is about double the ratio (approximately 12%) shown in the original 2008 inventory.[7]

The EPA's new reports have led to considerable controversy about the impact of upstream emissions on the comparative GHG intensity of natural gas-based applications. One report, by Pro Publica, suggested that the EPA's modified methodology in estimating upstream emissions "dramatically chang[es]" the overall GHG intensity of gas-fired power generation.[8] However, this interpretation confuses the change in the upstream and non-combustion emissions (which the EPA doubled) with the change in fuel chain GHG emissions (which, as discussed below, increase approximately 10%). It also omits upstream GHG emissions from coal mining; these upstream emissions represent about half of the revised, higher upstream emissions from gas production on a per-kWh basis.

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[6] *Technical Support Document: Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry,* EPA-HQ-OAR-2009-0923-3610, at http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2009-0923-3610.

[7] *See* U.S. Environmental Protection Agency (EPA), *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008* (2010), EPA-430-R-10-006. The 2008 upstream emissions would be 10% of combustion emissions based on the 2008 inventory or 20% based on the 2009 inventory. Our estimates are higher, because we use the latest IPCC GWP ratio of 25 for methane, rather than the value of 21 used by the EPA.

[8] *See* Lustgarten, A., *Climate Benefits of Natural Gas May Be Overstated*, Propublica.org, 25 January 2011, at http://www.propublica.org/article/natural-gas-and-coal-pollution-gap-in-doubt. The article asserts that "when all [the] emissions are counted, gas may be as little as 25% cleaner than coal, and perhaps even less."

Another widely publicized paper by Cornell Professor Robert Howarth and colleagues[9] draws on the EPA's revised data and other sources to conclude that "3.6% to 7.9% of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the life-time of a well." Using these data, which Howarth et al. admit is "not well documented,"[10] and novel short term (20 year) GWP values for methane that are 46% higher than the most recent values published by the IPCC,[11] the Cornell team concluded that, "the GHG footprint for shale gas is at least 20% greater than and perhaps more than twice as great as that for coal" per unit of energy; [o]ver the 100-year time frame the GHG footprint is comparable to that for coal…"[12]

Howarth et al. stress that the foregoing analysis "does not consider the efficiency of final use" for gas and coal. The paper nevertheless asserts that "even assuming the greater

[9] R.W. Howarth, R. Santoro and A. Ingraffa, "Methane and the Greenhouse-Gas Footprint of Natural Gas From Shale Formations." Available at: http://www.eeb.cornell.edu/howarth/Howarth et al 2011.pdf. The paper has been accepted by the journal, *Climatic Change Letters*.

[10] *Id.* p. 4. Notably, 85% of the additional emissions attributable to shale gas wells – put at 1.9% of total output – are estimated from "2 shale gas and 3 tight-sand formations" with that data showing emissions varying from .6% to 3.2% of life time production. *Id.* At Table 1. Howarth et al. do not use any data from 2010 shale gas wells in the Marcellus or other large fields outside Louisiana.

[11] Howarth et al. assign a GWP value of 105 to methane on a 20 year time horizon and 33 over 100 years (plus or minus 23 percent) based on a single 2009 research paper by a team at NASA's Goddard Institute For Space Studies at Columbia University. *See* D.T. Shindell et al. "Improved Attribution of Climate Forcing to Emissions". Science vol 326: pp. 716-718 (30 October 2009). The Goddard team's revised GWP values for methane are based on a new approach to climate modeling that seeks to account for the potential interaction between methane, ozone precursors and aerosols -- airborne particles such as sulphate molecules. These molecules, produced when sulphur dioxide is oxidised in the atmosphere, have a cooling effect on the climate as they reflect heat but, according to Shindell et al., increased levels of methane lead to chemical reactions that reduce the level of sulphates. Thus, calculations of GWP that include these gas-aerosol linkages substantially increases the value for methane. While we lack the specialized expertise to assess the models from which these results derive, we note that the higher figures estimated by Shindell et al. stem from a unique modeling exercise (rather than empirical observations) and have yet to be subject to the international peer review that attends revisions of the IPCC's GWP estimates, which are used by the worldwide scientific community for many purposes. Consequently, given the magnitude of the claimed revision in the GWP numbers, and the critical role the GWP values appear to have on the conclusions of Howarth et al. (*see* note 14 infra), we think it is premature, at best, to accept the Cornell team's work, including their emphasis on 20 year, rather than 100 year, GWP values. At a minimum, Howarth et al. should have presented comparative results based on the GWP values currently accepted by the IPCC.

[12] Howarth et al. *Id.,* p. 3.

efficiency of gas-fired electricity generation the GHG footprint of shale gas approaches or exceeds coal."[13]

This conclusion is suspect for two major reasons, wholly apart from the questionable data used to estimate upstream emissions and the reliance on inflated GWP values.[14]

First, Howarth et al. did not calculate the GHG intensity associated with the combination of gas and coal per kilowatt hour of electricity based on the actual power sector efficiency data used here. Rather, Howarth's conclusion was based on theoretical calculation of the amount of CO2 emitted per unit of *fuel energy input*. This theoretical comparison disregards the efficiency advantage of modern gas-fired generation on an *electric energy output* (kilowatt-hour) basis. And the ultimate output – electricity – is all important, of course, when comparing the fuel-cycle emissions for gas and coal because, with limited exception, coal is not combusted for anything other than electricity generation in the U.S..

Second, as Howarth et al. concede, the additional methane emissions associated with shale gas production (that is, flow back leakage from well completion plus "drill out" emissions[15]) "can be reduced by up to 90% through Reduced Emission Completions technologies or (REC)" [16] according to the 2010 EPA technical report cited above. The foregoing document is also supported by recent industry submissions to the EPA regarding the agency's new emissions data. [17]

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[13] Howarth et al. *Id.*, p. 9.

[14] The use of GWP values that are 46% higher than the IPCC values for a 20 year time span appears, in and of itself, to account for the 20% greater GHG footprint Howarth et al. attribute to shale gas versus coal over a 20 year time horizon.

[15] "Drill out" emissions refer to leakage emitted when the well plugs set to separate stages or sections in the horizontal fracking process are drilled out to release gas for production.

[16] Howarth et al. *Id.*, p. 9.

[17] *See*, for example, El Paso Corp. *El Paso Comments on the Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009* (2011), letter from Fiji George to U.S. EPA, 25 March 2011, on file with ACSF. One major emission reduction method to reduce flow back leakage involves the uniform application of plunger or artificial lifts to optimize the opening and closing of well shut off valves. In some cases, El Paso notes, state regulation requires pre-production flaring of some gas (which reduces its GHG footprint) when other options are unavailable.

In sum, much of the press generated by the Howarth et al. paper (e.g., "Shale gas 'worse than coal' for climate"[18]) is misleading. The simple fact is that Howarth et al. did not carry out a full national fuel chain assessment of natural gas and coal for electricity generation based upon the relevant metric (e.g., GHG emissions per kilowatt hour generated). Rather, the Cornell team primarily focused on the pre-combustion footprint of shale gas and other fuels. In contrast, this paper looks at emissions from both the production and combustion portion of the fuel chain for natural gas-fired and coal-fired electric power. We proceed as follows.

Analysis

First, we tabulated the impact of the EPA's new change in upstream emission accounting on the fuel chain GHG emissions of natural gas and gas-fired electricity. We then compared gas-fired and coal-fired electricity using a consistent methodology that includes these updated inputs.

Our results show that, while the increase in estimated GHG emissions from gas-fired generation is significant, these emissions are still substantially less per kilowatt-hour (kWh) of electricity than from coal-fired generation. Based on the revised EPA data and average generation heat rates, we find that *existing gas-fired generation is still about 52% less GHG intensive than existing coal-fired generation*, on average. Similarly, a new gas-fired combined-cycle unit produces about 53% less GHG emissions per kWh than a new coal-fired steam unit.

As noted earlier, this analysis compares the effects of different GHGs (e.g., carbon dioxide (CO2), nitrous oxide (N2O) and methane (CH4)) based on the conventional 100 year global warming potential (GWP) established by the U.N.'s Intergovernmental Panel on Climate Change (IPCC). The IPCC chose this convention because CO2 and most

[18] *See e.g.*, Richard Black, "Shale gas 'worse than coal' for climate," BBC News, posted 12 April 2011, at http://www.bbc.co.uk/news/science-environment-13053040. See also Tom Zeller Jr., "Studies Say Natural Gas Has Its Own Environmental Problems," New York Times, April 11, 2011, at: http://www.nytimes.com/2011/04/12/business/energy-environment/12gas.html?_r=1

other GHGs remain in the atmosphere for 200 years or more. Some analysts adopt shorter term (e.g., 20 year) GWP values to evaluate GHG footprint because certain short-lived GHGs such as methane have a much higher average GWP over that time horizon (e.g., methane has an average atmospheric life of 12 years). However, fuel comparisons based on 20 year GWPs may be counterproductive in weighing the options for stabilizing global GHG emissions over the longer term (e.g., 2030-2100), because they underweight the consequences of committing to greater emissions from CO2 and other GHGs that, unlike methane, will impact the climate for hundreds of years.

Combustion Emissions: Efficiency and Fuel Carbon

Basic statistics related to the energy used for gas- and coal-fired electricity generation are shown in Table 1.[19] This table uses 2008 data because that was the last year that GHG emissions from natural gas systems were calculated using EPA's older method, enabling a simple comparison with the new estimates.

Table 1. 2008 Electric Generation and CO2 Emission Statistics for Coal and Natural Gas

Fuel	Coal	Natural Gas
Total Combustion CO2 Emissions (million metric tons)	2072	1,224
Electric Generation CO2 Emissions (million metric tons)	1958	362
Net Generation Energy (Quads, or 10^{15} Btu)	20.55	6.80
Fuel Carbon Content (kg-CO2/MMBtu)	95.3	53.2
Average Heat Rate, or Generation Fuel Efficiency (Btu/kWh)	10350	7700
Total Electric Generation (billion kWh)	1986	883
Combustion-Only CO2 Emission Intensity (kg-CO2/kWh)	0.986	0.410

Based on the values shown in Table 1 we see that, on average, natural gas contains 44% less carbon per unit of energy than does coal for power generation.[20] Also, gas-fired

[19] These statistics are derived from U.S. Energy Information Administration (EIA) (2010). *Annual Energy Review 2009*, DOE/EIA-0384 (2009), at http://www.eia.doe.gov/aer/pdf/aer.pdf

[20] While the energy and carbon content of pipeline quality natural gas is uniform throughout the US (1000Btu/cuft), regional steam coal resources vary considerably from 4000 to over 15000 Btu/lb. The coal carbon content value in Table 1 is the average of all coal used for power generation in the U.S. This

electricity generally has a lower heat rate, indicating an efficiency advantage and, on average, uses 26% less energy than coal-fired generation to generate each kWh of electricity.[21] Combining these figures, the CO2 emission intensity for gas-fired generation is 58% lower on average than coal-fired generation. The direct CO2 emissions per kWh are therefore more than twice as high on average for coal-fired power (0.99 kg-CO2/kWh) than for power from gas-fired generation (0.41 kg-CO2/kWh).

Calculating Fuel Chain Emissions

In addition to direct CO2 emissions from fossil fuel combustion, the GHG impact of using a fuel includes emissions of methane and other GHGs upstream in the fuel supply chain, as well as non-CO2 GHGs from combustion. To estimate the fuel chain emissions for power generation, we add emissions of non-combustion CO2 and methane (CH4), expressed as CO2-equivalents (CO2e).[22] Also, we include the CO2-equivalent values of N2O and methane emissions that result, in addition to CO2, from combustion of the fuels. This is not a complete fuel-cycle analysis for these fuels, but it is a consistent accounting of the main GHG sources that are identified in the national inventory.[23]

We add upstream emissions for both coal and natural gas and, in the case of natural gas, compare the old and new EPA estimates, as well as the values used by the U.S. Energy

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average is weighted according to the amount of energy generated, by simply dividing total emissions by total fuel energy used for generation in the coal-fired fleet.

[21] Heat rate (efficiency) values for both coal- and gas-fired generation units vary widely. By and large, gas-fired combined-cycle gas turbine (CCGT), which competes directly with coal, is more efficient than coal-fired steam units. Simple-cycle combustion turbines are less efficient and used mostly to meet load peaks.

[22] Tons of CO2e reflect the emissions of all greenhouse gases, accounting for the varying atmospheric lifetimes and radiative forcing power of the gases including CO2, N2O, methane (CH4) and others. CO2e is thus the equivalent number of tons of CO2 alone that would cause the same total radiative forcing, integrated over a 100-year time horizon. Because we use the more recent IPCC Fourth Assessment Report (2007) data [in which the GWP for methane is 25] rather than the Second Assessment Report (1995) data used in EPA's national GHG inventory [in which the GWP for methane was 21] our estimates of the CO2e values for methane are about 20% higher than those reported in the EPA documents cited here. Values for N2O are nearly unchanged between the two sources.

[23] Of the potential fuel chain GHG emissions sources not included here, the most significant is likely to be CO2 emissions from energy use in the production and transport of the fuels (e.g., pipeline compressors, coal trucks).

Information Administration (EIA) in the Department of Energy's 2008 GHG Inventory.[24] We sought to explore the implications of the potential range of results from using these uncertain data, without concluding here that one data set is necessarily more accurate than another. For example, detailed fuel-cycle emission studies have shown lower GHG emissions for natural gas than the EPA inventory results.[25] Moreover, if further research lowers the EPA's recent estimates of methane emissions from gas production, as some industry critics suggest, the resulting fuel chain GHG intensity values will also lie within the range that we explore here.

Our calculations are summarized in Table 2. First, since upstream emissions result from producing coal and gas that is used by consumers other than for electric generation, we need to allocate these emissions according to the total consumption of each fuel. We divide the sum of reported upstream emissions of CO2 (Line 3) in the natural gas fuel chain (from flaring and venting) and methane (Line 4) in both coal and natural gas fuel chains by the total CO2 emissions from combustion of each fuel (Line 1). The resulting ratio in Line 5 is about 4% for coal, and 12-23% for gas, depending on the data source.

[24] U.S. Energy Information Administration (EIA). *Emissions of Greenhouse Gas in the United States 2008* (2009), DOE/EIA-0573, at http://www.eia.doe.gov/oiaf/1605/ggrpt/pdf/0573(2008).pdf

[25] *See* National Energy Technology Laboratory (NETL). *Life Cycle Analysis: Power Studies Compilation Report* (2010), at http://www.netl.doe.gov/energy-analyses/pubs/PowerLCA_Comp_Rep.pdf

Table 2. Estimation of 2008 Fuel Chain GHG Emissions from Coal- and Natural-Gas-Fired Electric Generation, with Comparison of Data Sources

Fuel	**Coal**	**Natural Gas (under Different Inventory Data Sources)**		
GHG Data Source	**EPA**	**EIA**	**EPA**	**EPA**
Inventory Version	**2008-revised**	**2008**	**2008**	**2008-revised**
1. Total Combustion CO2 Emissions (million metric tons)	2072	1,242	1,227	1,224
2. Electric Generation CO2 Emissions (million metric tons)	1958	362	362	362
3. Upstream Fuel Chain CO2 Emissions (million metric tons)	0	0	30	33
4. Upstream CH4 Emissions as CO2e (million metric tons) GWP = 25	80	213	115	252
5. Upstream CO2e Emissions as % of Total Combustion CO2 Emissions	**3.9%**	**17.1%**	**11.9%**	**23.4%**
6. Electric Generation CH4 Emissions as CO2e (million metric tons) GWP = 25	0.5	0.1	0.1	0.1
7. Electric Generation N2O Emissions as CO2e (million metric tons)	9.6	0.2	0.2	0.2
8. CH4/N2O CO2e Emissions as % of Generation CO2 Emissions	**0.5%**	**0.1%**	**0.1%**	**0.1%**
9. Total Upstream + non-CO2 Emissions as % of Generation CO2 Emissions	**4.4%**	**17.2%**	**11.9%**	**23.4%**
10. Total Electric Generation CO2e Emissions (million metric tons)	**2044**	**424**	**405**	**446**
11. Fuel-based GHG Intensity (kg-CO2e/MMBtu)	**99.4**	**62.4**	**59.5**	**65.6**
12. Total Electric Generation (billion kWh)	1986	883	883	883
13. Combustion-Only CO2 Emission Intensity (kg-CO2/kWh)	0.986	0.410	0.410	0.410
14. Combustion + Fuel Chain GHG Emission Intensity (kg-CO2e/kWh)	**1.029**	**0.481**	**0.459**	**0.505**

Next, since combustion emissions of methane (Line 6) and N2O (Line 7) are reported specifically for power generation, we divide these emissions by the total CO2 emissions from combustion of both coal and natural gas fuel for power generation (Line 2). The resulting ratio in Line 8 is 0.5% for coal, and 0.1% for gas. These two ratios (Lines 5 and 8) are then added together to get the ratio in Line 9, "Total Upstream + non-CO2 Emissions as % of Generation CO2 Emissions," which is then added to 100% and

multiplied by Line 2 to arrive at Line 10, "Total Electric Generation CO2e Emissions" for both coal and natural gas power generation.[26]

After one accounts for the upstream and non-CO2 GHG emissions reported in the 2011 EPA inventory in terms of CO2e, fuel chain emissions from coal-fired generation are increased 4.4%, compared to combustion CO2 emissions only (the ratio in Table 2, Line 9). The GHG emissions due to methane losses from mining add about 4% to the CO2e values for coal,[27] and methane and N2O emissions from stationary combustion add about 0.5% to the CO2e values for coal.

Fuel chain GHG emissions from gas-fired generation are increased by 23.4% using the most recent EPA data, which roughly doubles the upstream and non-combustion GHG emissions compared to the previous EPA inventory. The GHG emissions due to methane losses from the gas production and transportation system add about 20% to the CO2e values for natural gas, while CO2 releases from production add about 3%. Methane and N2O emissions from stationary combustion add an insignificant amount. Note that data from the EIA inventory yield CO2e estimates between the two EPA results, and that EIA used upstream methane emission values that are closer to the revised, higher EPA values.

Comparing Fuel Chain GHG Emissions from Natural Gas and Coal

These additional fuel chain GHG emissions raise the CO2e emission estimates for both coal- and gas-fired generation. The fuel chain GHG intensity of coal as a fuel is 99.4 kg-CO2e/MMBtu (see Table 2, Line 11), compared to a combustion-only CO2 intensity of 95.3 kg-CO2e/MMBtu, which represents the carbon content of the fuel itself. Accounting for the revised, but unconfirmed, EPA upstream methane emissions data, the fuel chain GHG intensity of natural gas as a fuel increases, from 59.5 kg-CO2e/MMBtu to 65.6 kg-CO2e/MMBtu (see Table 2, Line 11), based on a combustion-only CO2

[26] Methane emissions in our analysis are based on a 100-year global warming potential value of 25 and are thus about 20% higher than the values reported in the EPA and EIA source documents, all of which use a GWP for methane of 21. The higher (25) GWP value for methane accords with the values adopted by the most recent IPCC Fourth Assessment; *See* note 2 *supra* Chapter 2, Table 2.14, p. 212.

[27] We exclude methane emissions from abandoned coal mines in our estimates of coal fuel chain emissions.

intensity of 53.2 kg-CO2/MMBtu. These fuel-related emission intensities do not account for differences in the efficiencies with which the fuels are used, for example to generate electricity.

Taking efficiencies (heat rates) for electricity generation into account, the emission-intensity difference between coal and natural gas is amplified. Based on the revised EPA data and average generation heat rates, gas-fired generation is still less than half as GHG intensive in CO2-equivalent terms, with a fuel chain GHG intensity of 0.51 kg-CO2e/kWh, compared to coal, with a GHG intensity of 1.03 kg-CO2e/kWh, a 51% difference (see Table 2, Line 14). Note that the incremental increase in the GHG intensity of gas-fired generation from EPA's data revisions, from 0.46 kg-CO2e/kWh to 0.51 kg-CO2e/kWh, represents about 4.5% of the GHG intensity of coal-fired generation.

Emission estimates and GHG intensities shown in Table 2 are based on average generation efficiency values for coal- and gas-fired generation. It is also instructive to consider fuel chain GHG emissions from new, more efficient generation units, and also for older coal-fired plants. These plants are now at risk of retirement, due to the cost of compliance with pending environmental regulations on SO2, NOx, mercury, coal ash waste and cooling (not to mention possible GHG regulation). How much GHG emissions would closing these units save? Table 3 compares each of these cases.

Table 3. Fuel Chain GHG Emissions by Generation Unit Type and Fuel

Generation Plant Type	Fuel-based GHG Intensity (kg-CO2e/MMBtu)	Heat Rate (Btu/kWh)	Electricity-based GHG Intensity (kg-CO2e/kWh)
New Gas-Fired Combined Cycle	65.6	6,500	0.427
Average Existing Gas-Fired Unit	65.6	7,700	0.505
New Coal-Fired Steam Unit	99.4	9,000	0.895
Average Existing Coal-Fired Unit	99.4	10,350	1.029
Older, At-Risk Coal-Fired Unit	99.4	11,750	1.168

The values in Table 3 show that today's average gas-fired generation unit produces about 44% less GHG emissions per kWh than a new coal-fired unit, about 51% less than the average coal-fired unit (as noted above), and about 57% less than a typical older, out-of-

compliance coal-fired unit. A new gas-fired combined-cycle unit produces about 52% less GHG emissions per kWh than a new coal-fired unit, about 58% less than the average coal-fired unit, and about 63% less than a typical older, out-of-compliance coal-fired unit.

Conclusions

On average, our paper shows that, using the most current U.S. national inventory data, and standard international assumptions on the relevant time horizon for estimating the GWP of methane and other GHGs, the large comparative GHG advantage of natural gas-fired power plants continues to outweigh the negative GHG impact from the estimated rates of methane leakage from natural gas production.

The EPA's large upward revision of estimated methane leakage rates from natural gas production is attributable primarily to new fugitive emissions from unconventional production (i.e., largely shale gas), and gas from these wells currently accounts for a small portion (approximately 20%) of total US production. Some natural gas producers have criticized the revised EPA methane emission estimates, contending that they are now unrealistically high.[28] Even researchers who believe that the revised EPA estimates of fugitive emissions from unconventional production are too low acknowledge that the industry can reduce such leakages by up to 90% using available technologies.

Consequently, even if the percentage of shale gas production increases to a third or more of total U.S. output, so long as the industry adopts available best practices, we expect that natural gas-fired electric power will retain its large comparative advantage in fuel chain GHG emissions over coal-fired generation.

[28] El Paso Corp. 2011, *op. cit*.

9:15–10:15 Session

Natural Gas and Carbon Capture and Storage (CCS): Framing the Issues

Vice President of Policy & Research,
American Clean Skies Foundation

JEROME HINKLE is the Vice President for Research for the American Clean Skies Foundation. Prior to joining the Foundation, he was Vice President for Policy and Government Affairs at the National Hydrogen Association, and served for several years as a Brookings Fellow for Senator Byron Dorgan, helping to craft legislation on advanced energy technologies, including the Hydrogen Title in the Energy Policy Act of 2005 and several others. For the US Department of Energy, he managed R&D programs in alternative engines and fuels, was a senior analyst in environmental policy and international energy security, and the chief economist for the US Naval Petroleum and Oil Shale Reserves. Education includes physics, mathematics and aerospace engineering, with advanced graduate work in international politics, economics and public policy.

Converging Factors

Jerome Hinkle
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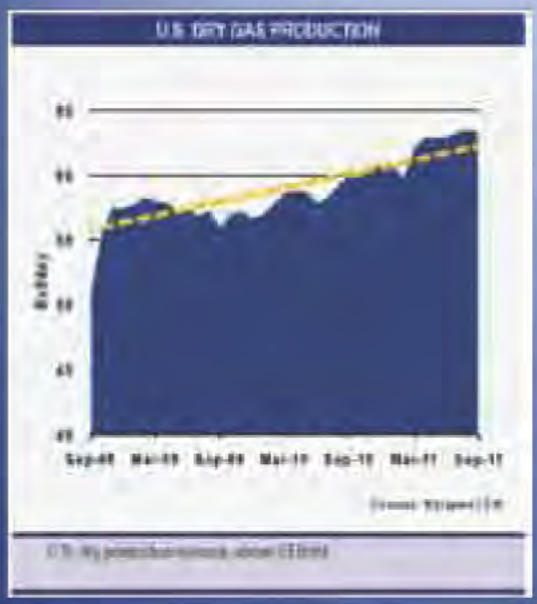
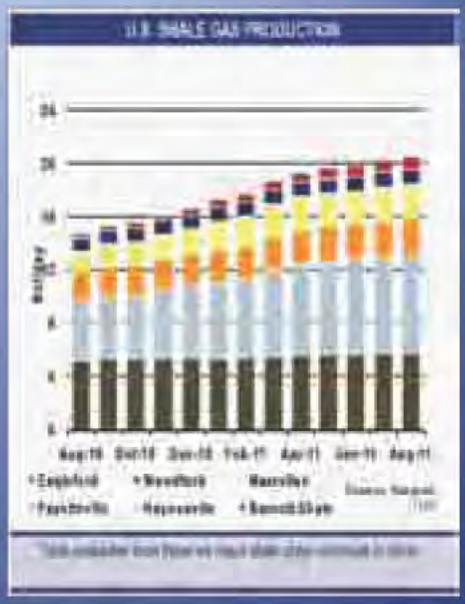
American Clean Skies Foundation jhinkle@cleanskies.org

From a Bridge to a Destination: Gas Fired Power After 2020
Hotel Monaco, Washington, DC
November 4, 2011





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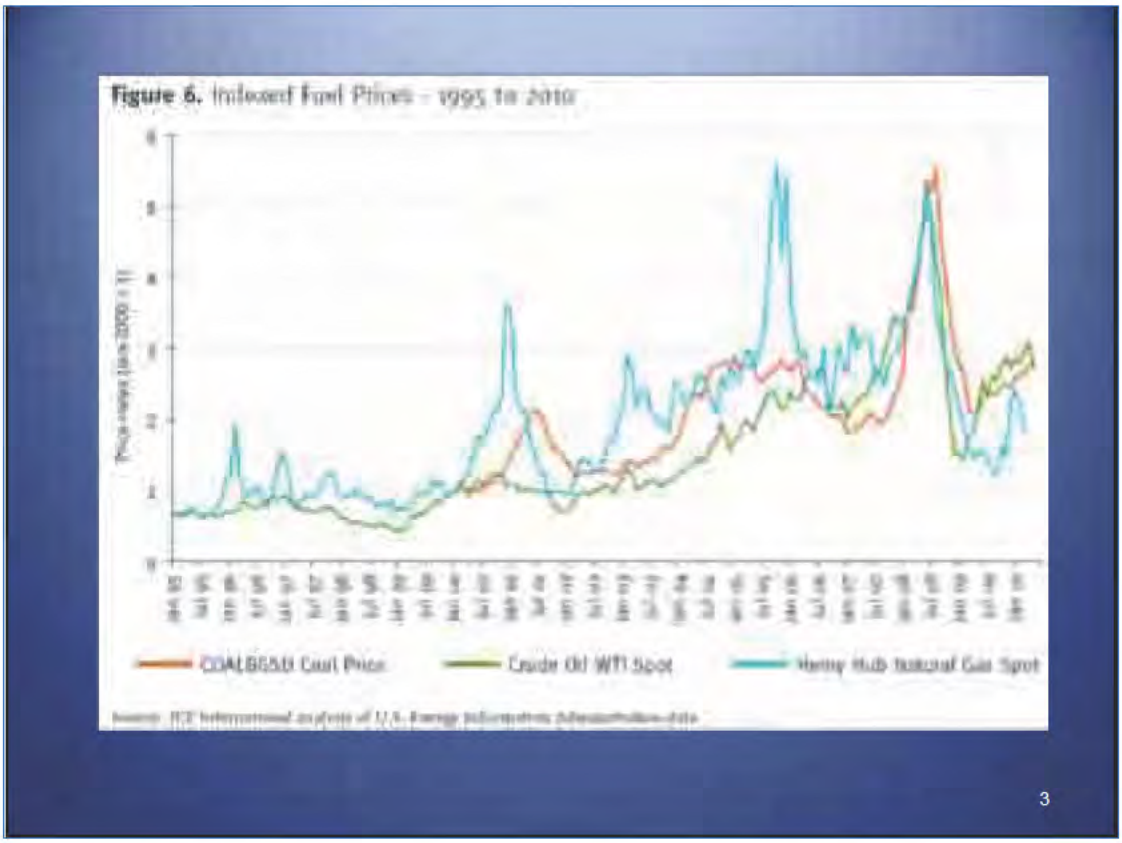
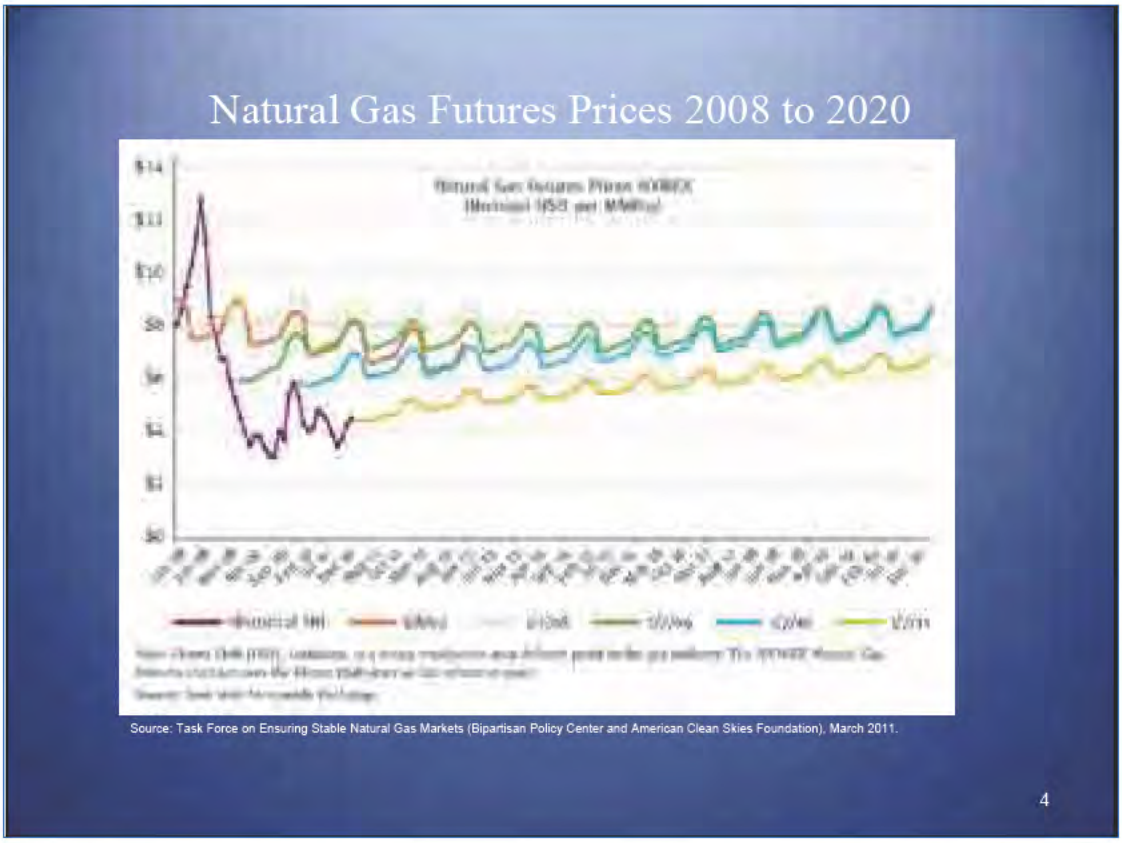
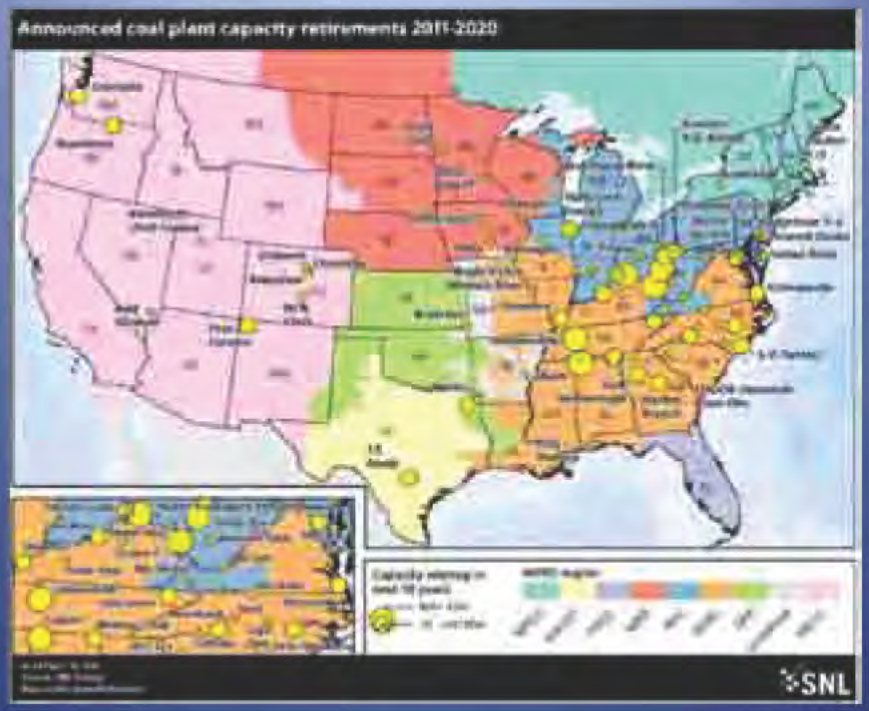
Converging Factors: Gas-Fired power After 2020







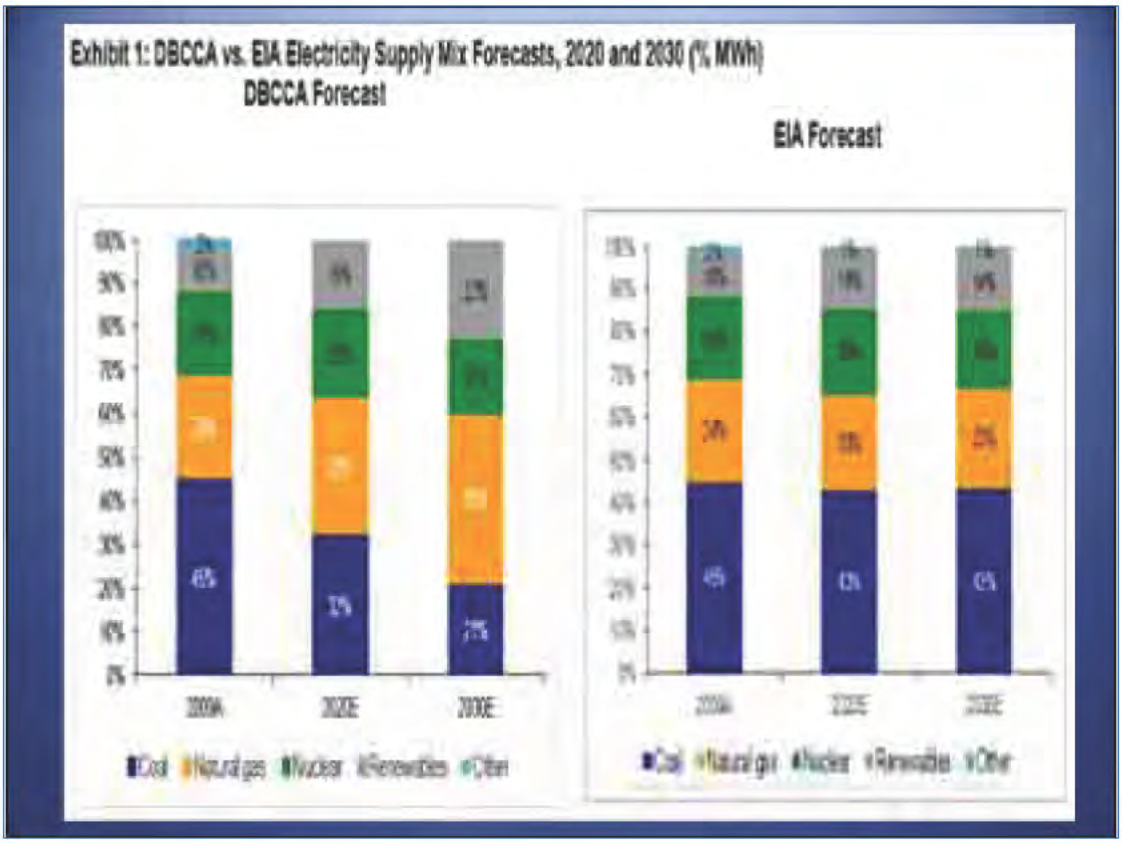
5

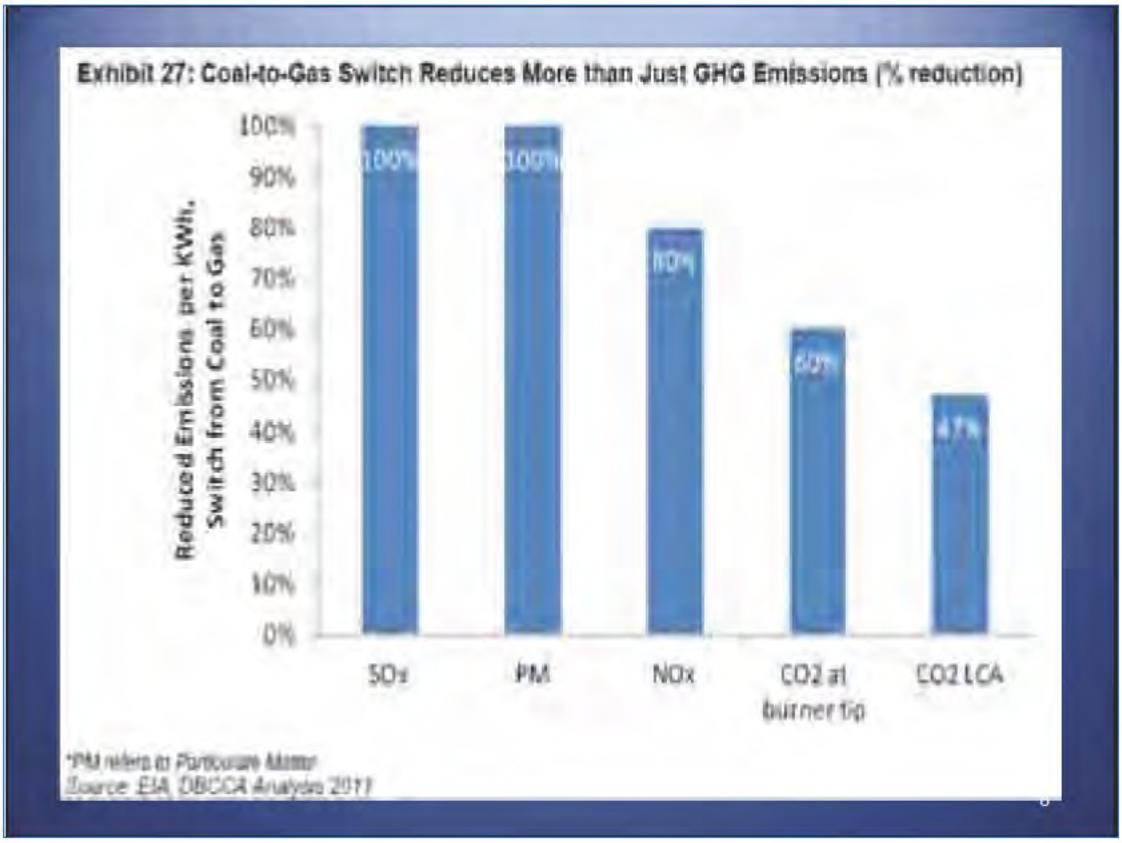
Coal Plant Retirements

- SNL, 2/11—16 GW announced
- SNL, 6/11—23 GW
- SNL, 9/11—26 GW
- Deutsche Bank Climate Change Advisors, 11/10—60 GW by 2020, + 92 GW 2020-2030
- Other studies estimate 35-101 GW 2010-2020

6

Converging Factors: Gas-Fired power After 2020



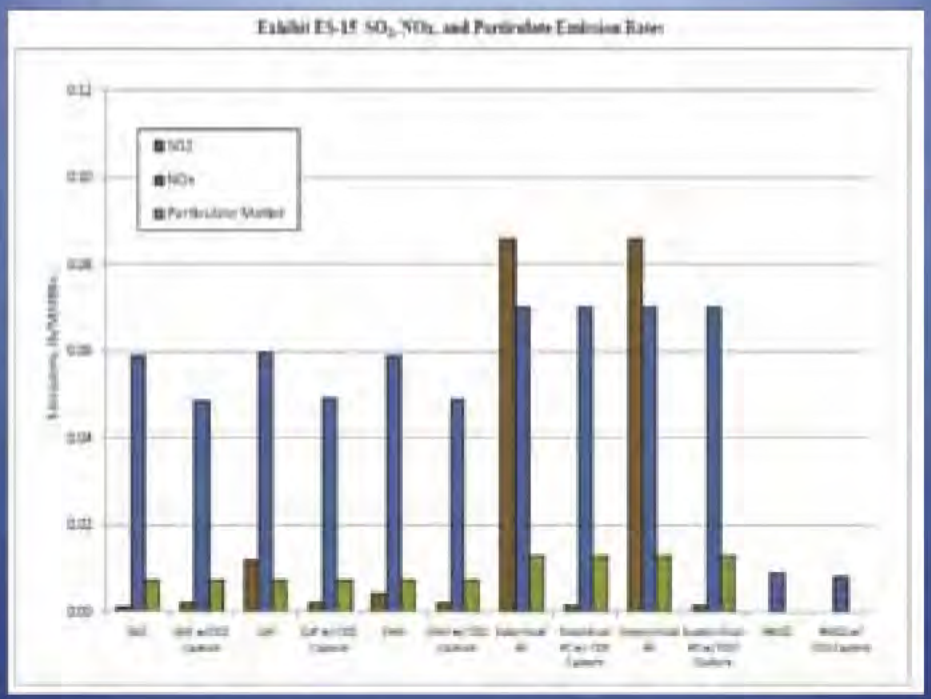


Gas Use 2009-35

AEO 2011

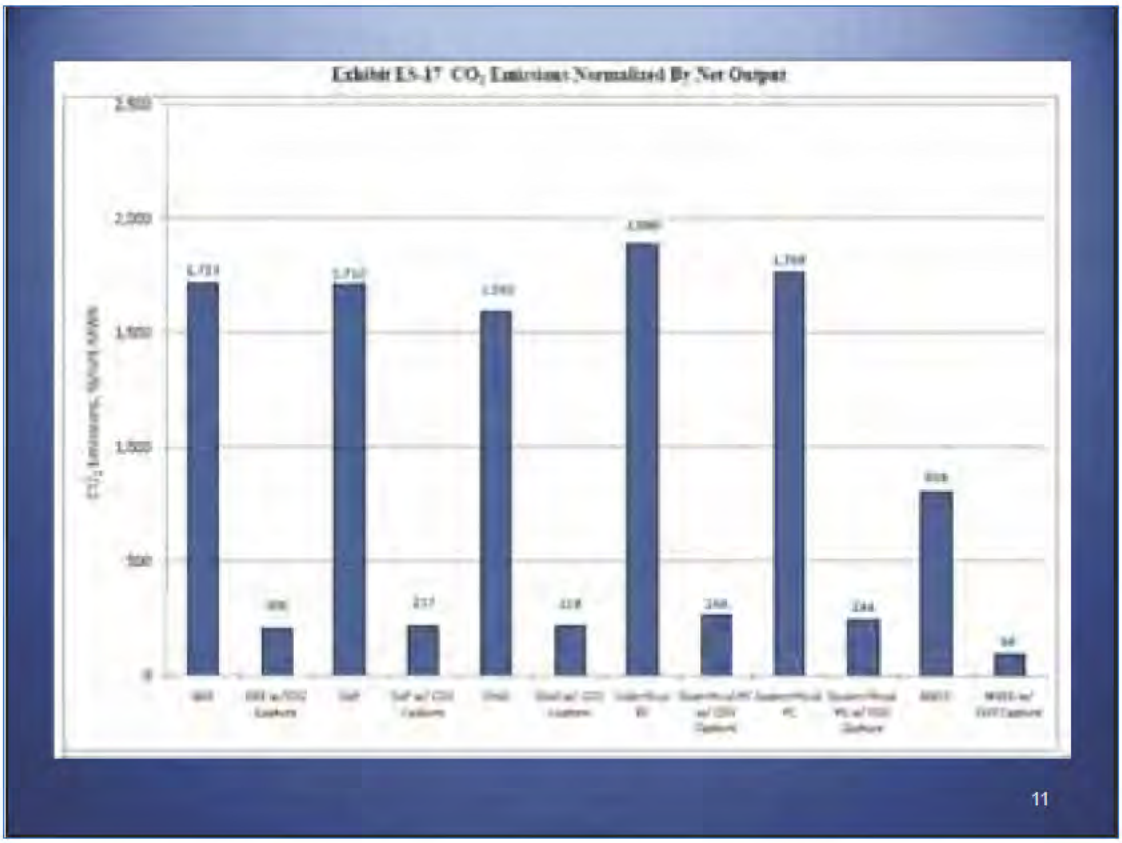
- **Residential 20.9% - 18% (flat ~ 4.8 Tcf)**
- **Commercial 13.7% - 14.4% (3.8 Tcf)**
- **Industrial 27% - 30 % (8 Tcf)**
- **Electric power 30% (flat ~ 7.9Tcf)**
- **Transportation 0.1% - .6%**

9



Source: *Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity.* Revision 2, November 2010. National Energy Technology Laboratory.

10



ACSF Review

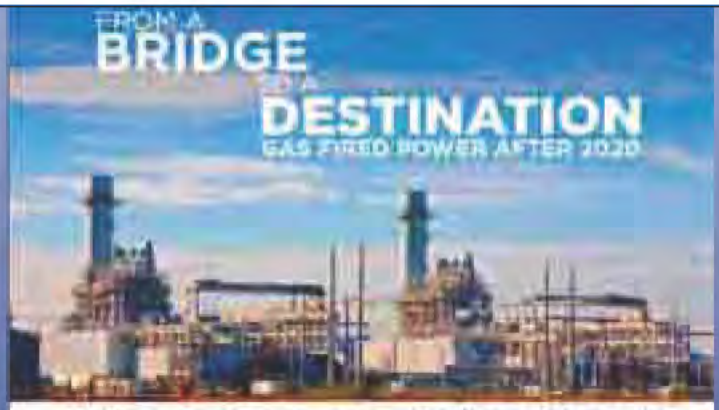
- Market, profitability and regulatory forces encouraging older coal plant retirements
- Integration of VERs with modern gas plants as renewables become cheaper and clean electricity more valuable
- Clean Air Act compliance
- Little DOE strategic planning on RD&D and deployment on CCS for gas—coal projects useful
- MIT, NPC, Secy. Chu see need
- DBCCA see 500,000 net new jobs from their 2030 grid mix

12

American Energy Innovation Council

- *Catalyzing American Ingenuity: The Role of Government in Energy Innovation* (Sept. 2011)
- Government must play an integral role in supporting energy innovation
- Energy technologies long-lived, capital intensive, slow ROI
- Energy markets not perfectly competitive, need help to anticipate future value of innovation
- DOE must work smarter; "1st of kind" technology commercialization engine with CEDA

13



A CARBON CAPTURE AND STORAGE LEADERSHIP FORUM FOR NATURAL GAS POWER PLANTS

Opportunities to advance technology, RD&D and policy

14

JOEL SWISHER, PhD, PE is a consulting professor of Civil and Environmental Engineering at Stanford University, where he teaches courses in greenhouse gas management and sustainable energy. He is also an advisor to the American Clean Skies Foundation (ACSF) and a Senior Fellow at Rocky Mountain Institute (RMI), where he was formerly managing director of research and consulting. Dr. Swisher has 30 years' experience in many areas of clean energy technology. He is a registered professional engineer, and holds a PhD in energy and environmental engineering from Stanford University.

Joel N. Swisher, PhD, PE

* This work is sponsored by the American Clean Skies Foundation

1

Today's Business Case for Integrating Clean Energy Resources to Replace Coal

- The electric power generation industry is confronted with the confluence of three powerful, game-changing forces:
  - Environmental regulation increasing the cost of legacy coal-fired generation plants
  - Availability of under-utilized gas-fired generation capacity
  - Mandated expansion of renewable generation, requiring more flexibility in the generation fleet

Today's Business Case for Integrating Clean Energy Resources to Replace Coal

- These forces create an historic opportunity to replace obsolete coal-fired generation fleet with a portfolio of:
  - Flexible, natural gas-fired generation, mostly existing
  - Variable renewable generation, mostly mandated
  - A range of demand-side energy and peak-capacity resources, mostly less expensive than any new generation source

Longer term, a vision of the Next Generation Utility, which relies on demand-side, renewable and low-carbon resources

- Massive improvement in energy efficiency in industry, buildings, and vehicles
- De-carbonize the electricity supply through aggressive renewable usage with gas-fired & demand-side firming
- Electrify direct fossil fuel loads, including cars/trucks

ICEs to PHEVs

- Smart grid to match time-varying loads and supply, including energy storage and demand-side resources

4

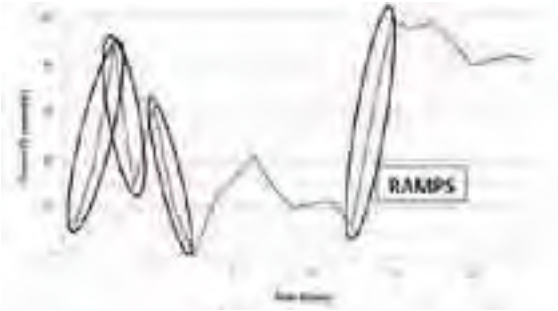
Advantages of gas-fired generation in the next generation utility

- Low-carbon generation
  - *Natural gas: 53, coal: 95 kgCO2/MMBtu from combustion*
  - *Gas-fired CCGT generation: 0.35, coal-fired steam: 0.85 kgCO2/kWh (we'll address upstream emissions later)*
- Co-generation
  - *Distributed production of power, heating (and cooling) makes maximum use of the fuel energy of natural gas (but not very compatible with CCS)*
- Flexibility to balance variable renewable generation
  - *A high-renewables generation fleet will need fast ramping resources to respond to the variations of both load and variable generation*
- Potential to displace gasoline via vehicle electrification
  - *Electricity from renewable and gas-fired generation, plus the efficiency advantages of electric drive, reduces vehicle CO2 intensity up to 80%*

5

What resources can provide flexibility?

- Steam Plants (coal and nuclear)?
  - Much variation but generally steam plants make a fleet less flexible, not more, due to increased startup and cycling costs, higher wear and tear, corrosion, shorter boiler & turbine life
  - Increases the need to curtail clean renewable power or risk operational problems or costly shut-downs of steam plants
- Demand response?
  - Cheap, limited frequency, duration



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What resources can provide flexibility?

- Gas-fired combined-cycle gas turbines (CCGT)
  - Pre-2000 units designed for baseload efficiency,but limited flexibility
  - New, efficient models with fast-start, high ramp rate, low minimum kW, moving to "hot start on the fly"
  - New CCGT products from GE, Siemens, Alstom can also be retrofitted
- Gas-fired combustion turbines and recip engines (gas or oil)
  - Simple-cycle gas turbine, engine peakers are flexible, <42% efficient

=> Gas-fired plants are the primary option for providing flexibility to enable renewables to grow 7

The greenhouse gas (GHG) emission footprint of natural gas use

Based on EPA inventories of US annual GHG emissions:

- Direct combustion CO2: 53.2 kgCO2/MMBtu (negligible N2O in addition)
- Fugitive methane (CH4) leaks: ~5 – 11 kgCO2e/MMBtu
  - Methane's Global Warming Potential (GWP) ratio is 25 (from IPCC 2007), although EPA still uses 21 (from IPCC 1995)
  - Based on leakage rates of 1-2.3% from EPA 2010, 2011 GHG inventory
  - Yes, the EPA more than doubled their estimated leakage rate!
  - Other (DoE) estimates: EIA 1.9%, NETL 1.7%
  - Other (widely refuted) literature estimates of leakage are as high as 8%! 8

The greenhouse gas (GHG) emission footprint of natural gas use (continued)

Based on EPA inventories of US annual GHG emissions:

- Direct combustion CO2: 53.2 kgCO2/MMBtu
- Fugitive methane (CH4) leaks: ~5 – 11 kgCO2e/MMBtu
- Upstream fuel combustion CO2: ~4.0 kgCO2/MMBtu
- Upstream venting/flaring CO2: ~1.4 kgCO2/MMBtu
- Total GHG footprint of natural gas: 63.6 – 69.6 kgCO2e/MMBtu
- Indirect non-combustion GHGs: 10.4 – 16.4 kgCO2e/MMBtu
  - 20% (2010 values) - 30% (2011 values) of the direct combustion footprint is GHGs not available for CCS

9

Reducing the upstream GHG footprint of gas

Gas producers (El Paso, Devon, etc.) disagree with the EPA's methods in the (much higher) 2011 inventory

- IHS/CERA observed the EPA's new leakage estimates are based on *rates of gas captured* during well completion, *not on measured rates of gas leaked*
- High leakage estimates would imply badly sub-standard safety, economic performance
- Of course, higher literature estimates considered discredited

Looking forward, the key is better data & documenting reductions

- Questionable EPA leakage estimates result of thin data sets from the field
- Advanced early production process (green completion) and other reduction/capture methods should become industry standards *with full documentation*

10

CO_2 from electricity generation

CO_2 from electricity generation {$kgCO_2/kWh$}

= Carbon content of fuel	*	Generation heat rate (efficiency)	/	1 million MMBtu/Btu
kgCO2/MMBtu		*Btu/kWh*		*MMBtu/Btu*

Comparison coal and natural gas-fired generation GHG emissions:

	Coal	Natural Gas	% increase/ decrease
Direct combustion CO2 (kgCO2/MMBtu)	95	53	-44%
Upstream & other GHGs (kgCO2e/MMBtu)	3	6	+120%
Fugitive methane leaks (kgCO2e/MMBtu)	4	5-11	+25 – 175%
Total GHG footprint (kgCO2e/MMBtu)	102	64 - 70	-32 - 37%
Heat rate of new generation (Btu/kWh)	8900	6500	-28%
New generation GHG rate (kgCO2e/kWh)	0.90	0.41 - 0.45	-50 - 54%
Non-combustion GHGs (kgCO2e/kWh)	0.06	0.07 – 0.11	+10 – 70%

11

*Upstream emissions from 2010, 2011 EPA GHG inventory, adjusted for methane GWP = 25

Coal vs. gas GHG emissions advantage*

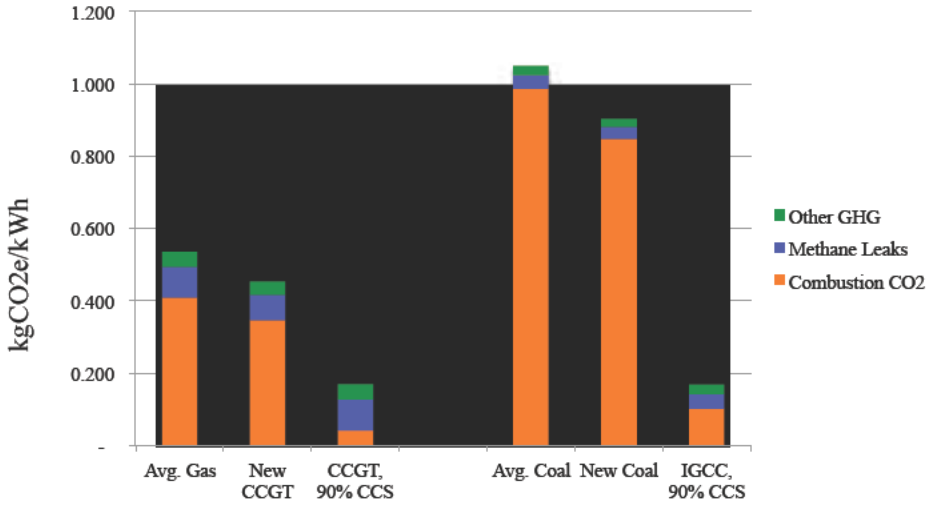
Plant type:	Heat rate Btu/kWh	kgCO2 / MMBtu	kgCO2e / MMBtu	kgCO2e / kWh
Average Gas	7700	53.2	69.6	0.54
New CCGT	6500	53.2	69.6	0.45
CCGT w/ 90% CCS	7800	5.3	21.7	0.17
Average Coal	10,350	95.3	101.5	1.05
New Coal	8900	95.3	101.5	0.90
IGCC w/ 90% CCS	10,700	9.5	15.7	0.17

12

* Upstream emissions from 2011 EPA GHG inventory, adjusted for methane GWP = 25

Coal vs. gas GHG emissions advantage*

At 2.3% gas leakage, gas/CCS = coal/CCS



* Upstream emissions from 2011 EPA GHG inventory, adjusted for methane GWP = 25

13

Natural gas-fired generation with CCS in a low-carbon generation portfolio

- Depending on upstream methane leakage rates, net GHG emissions from gas-fired CCGT with CCS could be very low
- Gas-fired CCGT with CCS is completely compatible with vehicle electrification with low-carbon power sources
- But not so much with distributed co-generation…
- The remaining question is the role of gas-fired generation with CCS in providing "flexibility" to balance variable renewables…

14

Can gas-fired generation with CCS deliver flexibility to balance variable renewables?

- Does C capture facility make gas-fired CCGTs strictly baseload plants that must run at nearly constant output?
- If so, they will not contribute flexibility to balance renewables…
- Such plants would still fit in a low-carbon portfolio with more flexible sources, but would provide only baseload or daily cycling

15

Can gas-fired generation with CCS deliver flexibility to balance variable renewables?

- On the other hand, if the CCS facility and its parasitic power consumption could be *ramped down during operation of the generation plant*:
  - Net power output would increase significantly on demand
  - CO2 emission rate would increase but only to the level of a CCGT and only when the plant's capacity is essential for grid reliability
  - To enable this "peaking" capacity, the CCS facility would have to be designed for cycling during continued operation – is this possible?

16

President,
C.O. Bauer Consulting, Inc.

CARL BAUER is president and founder of C.O. Bauer Consulting, Inc., headquartered in Pittsburgh, PA. Carl has over 35 years of industry and public service experience in technology development, energy systems, policy analysis, and executive management. Before establishing C.O. Bauer Inc., Bauer was Director of the National Energy Technology Laboratory (NETL).

Carl's education includes a Bachelor's degree from the U.S. Naval Academy in Marine Engineering and a Master's degree from the Naval Nuclear Power Engineering Program. He has participated in additional postgraduate programs and courses at the Wharton School of Business and George Washington University in business administration, finance, and management, and has completed executive management education at Harvard University's John F. Kennedy School of Government.

Mr. Bauer was responsible for directing and overseeing the implementation of major science and technology development programs at the Lab as well as $1 billion of jointly funded RD&D with the Energy Industry. This includes:

- Directing the focus of analysis relating to energy and electricity technologies and environmental policies
- Carbon capture and storage for power generation and industry.
- Advanced power generation and hydrogen production.
- Environmental controls for existing coal-fired power plants.
- High-efficiency, low-impact oil and natural gas exploration, production, and processing.
- Energy efficiency and renewable energy.
- Energy system analyses of technologies, public benefits, and current trends.

Presently Carl is employed as consultant and advisor in the following activities:

- Chairman, California Carbon Capture Storage Review Panel for the California Public Utility Commission, California Energy Commission and California Air Resources Board
- Australian Global Carbon Capture Storage Institute (GCCSI) Technical Advisory Board Member
- Member of the Advisory Board to WVU Advanced Energy Institute
- University of Wyoming, School of Energy Resources, Advisory Board Member
- Lawrence Livermore National Laboratory, Consultant to Director's Office
- Southern California Edison, Technical Consultant
- ARTIS Research and Risk Modeling Institute Fellow, Chair of Center for Energy and Natural Resources
- Various Venture Capital technology investment companies

From a Bridge to a Destination. Gas Fired Power Plants and Carbon Capture Storage and Utilization (CCUS)

Natural Gas and CCUS: Framing the Issues

American Clean Skies Foundation
November 4, 2011

Carl O. Bauer
Chairman California CCS Review Panel
Director (Retired) US DOE National Energy Technology Laboratory
President C.O. Bauer Consulting, Inc.

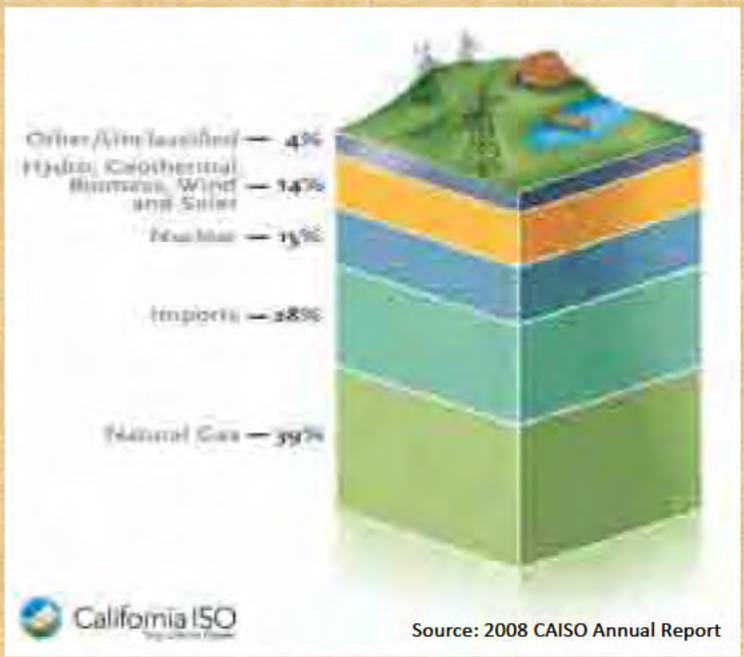
Why Care About CCUS?

CA Assembly Bill 32 with CAP&TRADE

"…sends the right policy signal to the market.."
"…When the nation addresses the growing danger of climate change… CA's climate plan will serve as the model…"

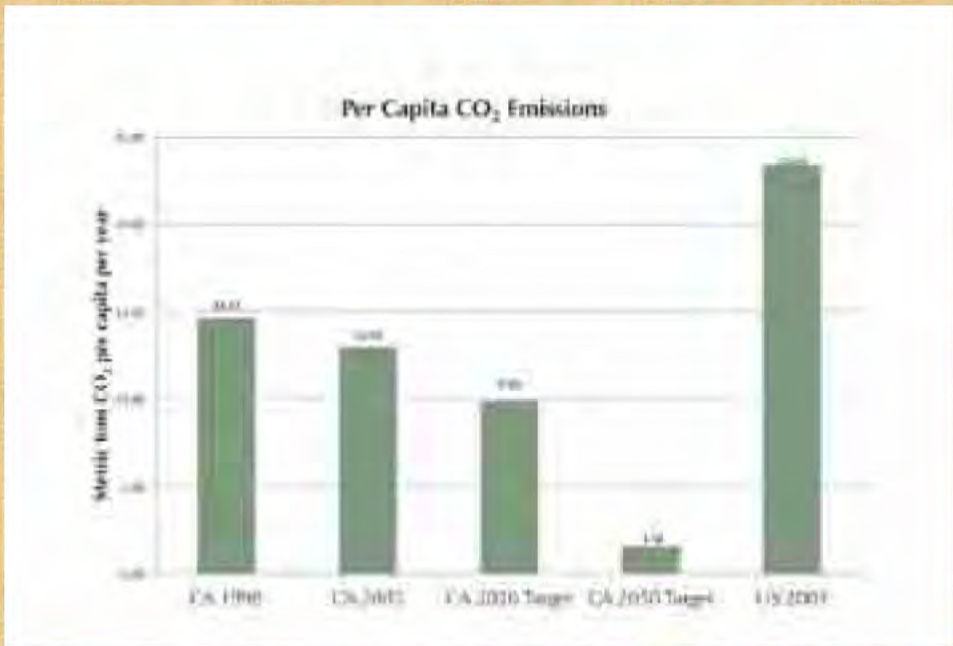
--CARB Chairwoman, Mary Nichols

California Electricity Resource Mix



Source: 2008 CAISO Annual Report

CA Per Capita CO2 Emissions



"CA Energy Future: The View to 2050", May 2011 by CA Council on Science and Technology

Issues To Be Resolved for CCSU

- Is Energy CARBON Constrained?
- TRUE Realization of NEED for CCSU!
- Federal and State Policy and Funding
- Firm Consistent and Understandable Business Incentives and Commitments
- Regulatory and Permitting Confidence
  - What is required, Who is responsible
  - Acceptable Actions Determinations
  - Uniform MVA Regulations

Issues To Be Resolved for CCUS

- Technical Issues
  - Capture Technology Economics both cost and efficiency of plant impacts
  - Transport of CO2
  - Storage Reservoir Operation
  - Confirmation of storage
- CO2 Utilization Offset Credit Policy
  - How CO2 confirmed and valued
- Long-term Liability
- Chronological Time Before Commercial Viability
- Impact on Water Resources

THANK YOU

- C.O. Bauer Consulting, Inc.
- crlbaur@gmail.com
- 412-337-8796

Seven Keys to Low-Carbon Innovation

1. **Managing Policy Uncertainty in Innovation Strategies**
2. **Clear Direction and Commitment from Leaders**
3. **User-focused Value Propositions**
4. **Business Model Innovations**
5. **Nexus Work**
6. **Robust Innovation Strategies**
7. **Partnerships, Investments, Acquisitions**

"The Business of Innovating: Bringing Low-Carbon Solutions to Market"
Pew Center on Global Climate Change; by *Andrew Hargadon , UC Davis*

10:30–Noon Session

CCS Technology & Economics for Natural Gas

Senior Research Engineer,
MIT Energy Initiative, Massachusetts
Institute of Technology

HOWARD HERZOG is senior research engineer in the MIT Energy Initiative. He received his undergraduate and graduate education in chemical engineering at MIT. He has industrial experience with Eastman Kodak (1972-1974), Stone & Webster (1975-1978), Aspen Technology (1981-1986), and Spectra Physics (1986-1988). Since 1989, he has been on the MIT research staff, where he works on sponsored research involving energy and the environment, with an emphasis on greenhouse gas mitigation technologies. He was a Coordinating Lead Author for the IPCC Special Report on Carbon Dioxide Capture and Storage (released September, 2005), a co-author on the MIT Future of Coal Study (released March 2007), and a US delegate to the Carbon Sequestration Leadership Forum's Technical Group (June 2003–September 2007). He was awarded the 2010 Greenman Award by the IEAGHG "in recognition of contributions made to the development of greenhouse gas control technologies".

CCS for Natural Gas

Howard Herzog
MIT
November 4, 2011

Howard Herzog / MIT Energy Initiative

What are Target Sources for CCS?

Source	Share (%)
Coal-Fired Power Plants	60
Other Power Plants (primarily gas)	19
Cement	7
Refineries	6
Iron and Steel	5
Petrochemical	3

Intergovernmental Panel on Climate Change (IPCC)
Special Report on Carbon Dioxide Capture and Storage
(2005)

Howard Herzog / MIT Energy Initiative

Interest in CCS with Gas

- Norway - Long history of R&D for CCS and gas
  - NTNU
  - Sintef
  - Statoil (Norsk Hydro)
  - Gassnova (Kårstø and Mongstad)
- California

Howard Herzog / MIT Energy Initiative

California


Technical and Regulatory Analysis of Adding CCS to NGCC Power Plants in California

Howard Herzog / MIT Energy Initiative

CCS Capture

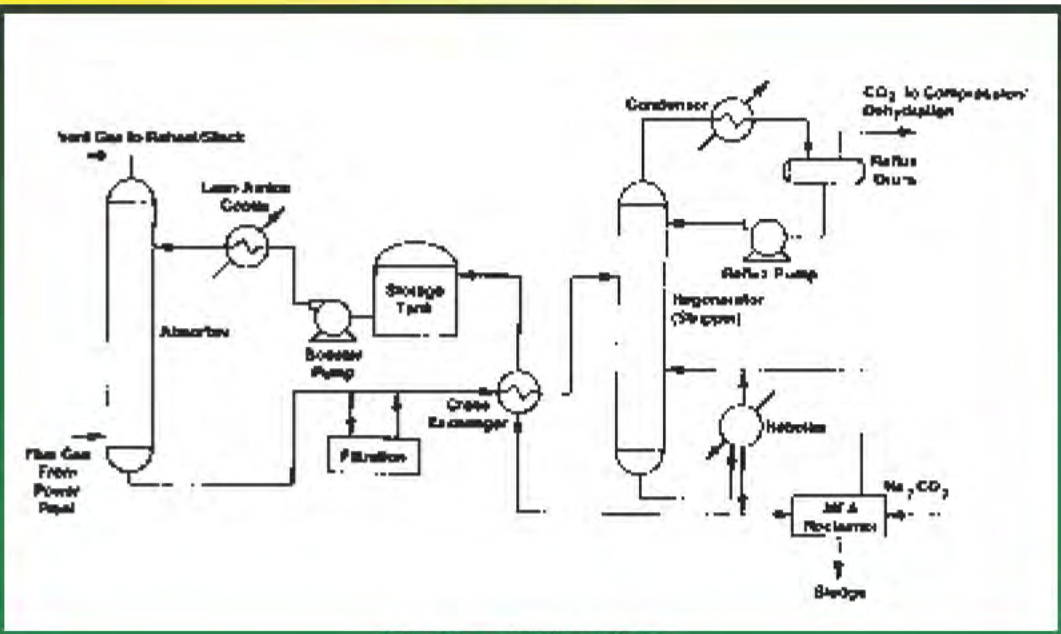
There are different types of CO_2 capture systems: post-combustion, pre-combustion and oxyfuel combustion.

Intergovernmental Panel on Climate Change (IPCC)
Special Report on Carbon Dioxide Capture and Storage
(2005)

For natural gas-fired power plants, a number of studies over the past 20 years all reach the same conclusion – post-combustion capture is the preferred route.

Howard Herzog / MIT Energy Initiative

Schematic of Amine Process for CO_2 Capture



Howard Herzog / MIT Energy Initiative

10:30–Noon Session

TCM - Norway

Howard Herzog / MIT Energy Initiative

Comparing Exhaust Gas Characteristics

Attribute	Gas	Coal	Implications for Gas
CO_2 Concentration	3-5% or ~7%	~12%	Larger Absorber
Particulates	No	Yes	Less Filtration
SO_2	No	Yes	Smaller Reclaimer
NO_x	Yes	Yes	
O_2 (excess air)	High	Low-Moderate	More Degradation and Corrosion
Capacity Factor	Low-Moderate	High	Higher Costs

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Comparing CCS Costs

$$\frac{\$}{tonCO2} \cdot \frac{tonCO2}{MWh} = \frac{\$}{MWh}$$

- Concentration matters
  - Coal almost always wins on \$/ton CO_2
  - Flue gas recycle can raise the concentration of CO_2 in the turbine exhaust gas (at a cost)
- Gas is less carbon intensive than coal
  - Gas almost always wins on \$/MWh

Howard Herzog / MIT Energy Initiative

Post-Combustion Capture Today's Technology

- Chemical solvents, primarily amines such as Monoethanolamine (MEA)
- Commercial Vendors
  - ABB/Lummus
  - Aker
  - Alstom chilled NH_3
  - Alstom/Dow
  - B&W
  - Cansolv/Shell
  - Fluor
  - HTC PureEnergy
  - Linde/BASF
  - MHI
  - Powerspan
  - Siemens

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Alternative approaches to chemical absorption

- Adsorption or membranes
  - Difficult due to low CO_2 partial pressure
- Other options
  - Biomimetric approaches (e.g., carbonic anhydrase)
  - Microalgae
  - Cryogenics/ phase separation
- Structured and Responsive Materials

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ARPA-E IMPACCT (15 Projects)

- ATK: A High Efficiency Inertial CO2 Extraction System - ICES
- Codexis, Inc.: Low-Cost Biological Catalyst to Enable Efficient CO2 Capture
- Earth & Environmental Engineering, Columbia University: Chemical and Biological Catalytic Enhancement of Weathering of Silicate Minerals as Novel Carbon Capture and Storage Technology
- GE Global Research: CO2 Capture Process Using Phase-Changing Absorbents
- Georgia Tech Research Corporation: High Performance MOF-polymer Composite Membranes for CO2 Capture
- Lawrence Berkeley National Laboratory: High-Throughput Discovery of Robust Metal-Organic Frameworks for CO2 Capture
- Lawrence Livermore National Security, LLNS: Catalytic Improvement of Solvent Capture Systems
- Massachusetts Institute of Technology: Electrochemically Mediated Separation for Carbon Capture and Mitigation
- Oak Ridge National Laboratory: High Performance CO2 Scrubbing Based on Hollow Fiber-Supported Designer Ionic Liquid Sponges
- Research Triangle Institute (RTI International): Novel Non-Aqueous CO2 Solvent-based Capture Process with Substantially Reduced Energy Penalties
- Sustainable Energy Solutions: Cryogenic Carbon Capture
- Texas A&M University: Stimuli-Responsive Metal-Organic Frameworks for Energy-Efficient Post-Combustion Carbon Dioxide Capture
- The Regents of the University of Colorado: Achieving a 10,000 GPU Permeance for Post-Combustion Carbon Capture with Gelled Ionic Liquid-Based Membranes
- University of Kentucky Research Foundation: A Solvent-Membrane Hybrid Post-combustion CO2 Capture Process for Existing Coal-Fired Power Plants
- University of Notre Dame: CO2 Capture with Ionic Liquids Involving Phase Change

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Other Issues

- Load following
  - More critical for gas than coal
  - Indications are that capture system can respond well
- Cycling
  - Gas has more shutdowns than coal
  - Capture system takes longer to start-up/shutdown
- Capacity Factor
  - Will probably limit CCS to "baseload" gas units

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Demonstration Projects under Development Involving Gas

Company	Location	Gov't Support (million $)	Size	Source	Fate
SSE Generation	Peterhead, Scotland, UK	NER 300	385 MW >1 Mt CO_2/yr	GTCC Exhaust	Depleted Gas Reservoir
Air Products & Chemicals	Port Arthur, TX	253	1 Mt CO_2/yr	Existing Steam Methane Reformers	EOR
NRG Energy	Parish, TX	167	60 MW 0.4 Mt CO_2/yr	Coal Exhaust	EOR

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10:30–Noon Session

Using Auxiliary Gas Power for CCS Energy Needs in Retrofitted Coal Power Plants

- Bashadi, S. and H. Herzog, "Using Auxiliary Gas Power for CCS Energy Needs in Retrofitted Coal Power Plants," presented at the 10th International Conference on Greenhouse Gas Control Technologies, Amsterdam, The Netherlands, September (2010).
  - http://sequestration.mit.edu/pdf/GHGT-10_Bashadi.pdf
- Sarah Bashadi's M.I.T. Masters Thesis (June 2010), "Using Auxiliary Gas Power for CCS Energy Needs in Retrofitted Coal Power Plants"
  - http://sequestration.mit.edu/pdf/SarahBashadi_Thesis_June2010.pdf

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Auxiliary Gas Power Summary

- Auxiliary plant positives
  - Lower CO_2 without loss of power production
  - No disruption to existing plant
  - Potential for lower overall costs
  - Significant excess power (may also be a negative)
- Auxiliary plant negatives
  - Large capital investment
  - CO_2 emissions from auxiliary plant uncontrolled
  - Gas price volatility

Howard Herzog / MIT Energy Initiative

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Howard Herzog / MIT Energy Initiative

Vice President,
Power Technologies for Government Affairs, Alstom Power Inc.

ROBERT HILTON In his current role as Vice President, Power Technologies for Government Affairs, Alstom Power Inc., Robert (Bob) Hilton provides information and technical data on power technology to state and federal regulators. During more than ten years with Alstom, Bob has held several positions of increasing responsibility including Vice President of Marketing for Alstom's global Air Pollution Control business, Vice President of Research & Development in air pollution control; Vice President of Alstom's Post Combustion Carbon Capture Programs; Director of Business Development; and Strategic Development Director.

Today, Hilton is responsible for providing technical guidance on regulatory and legislative issues for Alstom and providing testimony to committees supporting Alstom's positions. He represents the Company in technical organizations, work groups and industry associations to process the Company's regulatory agenda and interfaces with state and federal officials to provide information on key issues. Additionally, Hilton provides guidance and input to the strategic and operational planning of the Alstom US business with regards to regulatory issues.

Hilton has been in the air pollution control field for over thirty years. His specialty is air pollution and the related issues of water and waste management. He holds a BS in Chemistry from Philadelphia College of Textiles and Science, an MBA in Finance from Drexel University in Philadelphia, and is past president and a member of the Board of Directors, Institute of Clean Air Companies. He is also the inventor of 15 US and foreign patents and applications and has authored numerous technical publications.

CCS and Its Economics

Presentation to CCS Leadership Forum
American Clean Skies Foundation

Robert G. Hilton

November 4, 2011

POWER | ALSTOM

Alstom: Three Activities

ALSTOM

Leading global provider of equipment & services for…

Power Generation

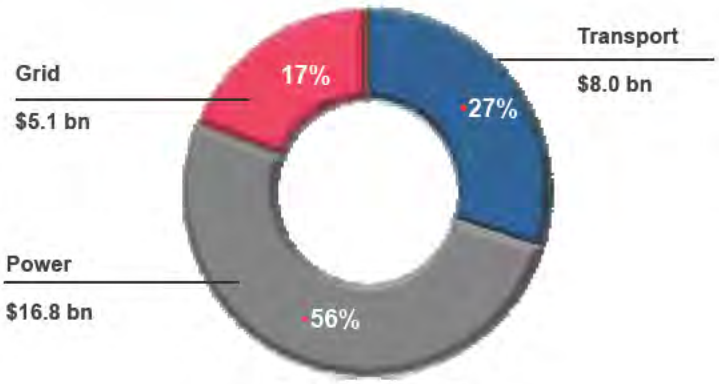
Rail Transportation

Power Transmission

Alstom in the U.S. - P 2 | © Alstom 2011

Strong & Sustained Sales, Worldwide

ALSTOM



Total sales 2010/11:
More than $29 billion USD

Key Facts & Figures:

- 93,500 employees in 100 countries
- 6% increase in sales from 2009/10 to 2010/11
- Steady increase in R&D investment to more than $1 bn USD in 2010//11
- ***Leading provider of innovative clean technology solutions***

Alstom in the U.S. - P 3 | © Alstom 2011

Alstom's Clean Power Strategy

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- Stabilising emissions by 2030 is possible thru solutions available today

Power Technologies for all Energy Sources

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Alstom in the U.S. - P 2 | © Alstom 2011

Fossil Support for Renewables

ALSTOM

- Ability to rapidly counter sudden drop in renewable generation is essential to preserving reliability
- Intermittent renewables must be accompanied by "on-demand" sources
  - Flexible, CCS controlled gas generation
  - Technology available today can deliver **>450MW in 10 mins**
  - "Parking" at below **20%** of plant output helps limit excess supply

Production Efficiency

ALSTOM

New Plants

•Coal: +20 p.p in efficiency saves 40% emissions

•Gas: +20 p.p in efficiency saves 33% emissions

•Fleet automation

•Optimization of the use of CO2 free power

60% of the 2030 installed base still to be built

Retrofit

•Plant Optimisation:

•-5% CO_2

•Turbine retrofit:

•-5% CO_2

•Boiler retrofit:

•-3% CO_2

•Automation Retrofit

•- 1% CO_2

60% of Carbon emitted in 2030 will come from today's installed base

Clean Power Day Malaysia - Clean Power Strategy - 07/11/2011 - P 7

Key Messages

ALSTOM

- CCS essential <u>and</u> affordable on both gas and coal.
- Fossil power with CCS costs no more than renewables.
- Policy support: an expectation of future regulation is needed to create the market for CCS.
- CCS deployment and demonstration needs further financial support:
  - Federal (or states) monies diverted such as EOR royalties or uniform wire charges
  - Subsidies as applied to renewables- level market place
  - Credit subsidies for sequestration
  - Credit sale into existing and developing carbon markets

Costs of CCS - PJ - 25 May 2011 - P 8

The CCS Reality today

ALSTOM

- 74 large-scale integrated CCS projects identified world-wide
  However many at risk or cancelled
- 14 projects operating or under construction
  On power/gas processing/synfuels/fertilizer plants
- ALL operating projects:
  Already capture CO2 as part of existing process
  Earn revenues by selling CO2 (e.g. EOR)
  Have advanced knowledge storage reservoirs (saves years of costly research)
- Many major demonstrations postponed indefinitely due to **uncertain policy** environment & **lack of funding**

Source: GCCSI Global Status of CCS: October 2011

Technology has hit speed-bump on the road to commercialization

Alstom activity on pilots and demonstrations 1st and 2nd generation CCS

ALSTOM

Operating

Vattenfall Schwarze Pumpe
Germany - 30 MWth
Oxy - Lignite

AEP Mountaineer
USA - 58 MWth
Chilled Ammonia - Coal

DOE/Alstom Windsor
US – 3 MWth
Chemical looping - Coal

Dow Chemical Co.
USA, West Virginia
Advanced Amines - Coal

Total Lacq
France - 30 MWth
Oxy - Gas

Alstom BSF Windsor
US - 15 MWth
Oxy - Coals

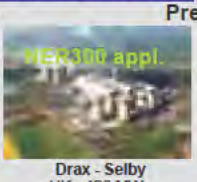
RFCS EU - Darmstad
Germany – 1 MWth
Chemical looping - Coal

Coming

TCM Mongstad
Norway - 40 MWth
Chilled Ammonia - Gas

EDF – Le Havre
France – 5 MWth Adv.
Amines - Coal

Pre-commercial Projects



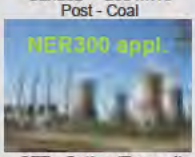
Drax - Selby
UK - 426 MWe
Oxy – Hard Coal

Vattenfall Jänschwalde
Germany - 250 MWe
Oxy - Lignite

Transalta
Canada - >200 MWe
Post - Coal

PGE Belchatow
Poland – 260 MWe Adv.
Amines - Lignite

AEP Mountaineer
USA – 235MWe
Chilled Ammonia - Coal



CET - Getica (Turceni)
Romania – >250MWe
Chilled Ammonia - Lignite

Selected for receiving EEPR funding

Selected by Alberta and Federal Canadian funding

Selected by US DOE to receive CCPI Round 3 funding

Costs of CCS - PJ - 25 May 2011 - P 10

CCS Cost Study – Key Assumptions

ALSTOM

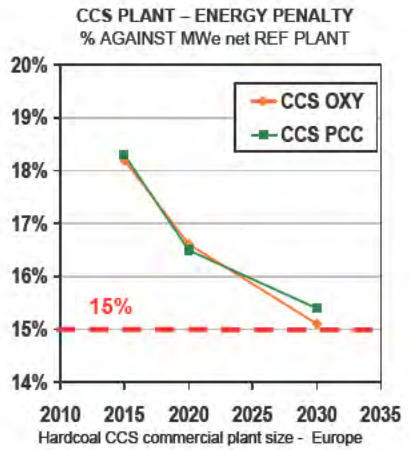
- Study based on **New Plant in Europe**
- Add-on costs for energy penalty and increase cost of electricity generation rises
- Considers cost of electricity generated with CCS & cost of CO2 avoided
- Two capture technologies: post-combustion and oxy-combustion using two fuels: hard coal and gas
- Coal and gas (combined cycle) plants with CCS operating as base-load
- CO2 capture rate of 90%
- Conservative learning curves up to 2030; based on Rubin/CMU curves

Alstom in the U.S. - P 23 | © Alstom 2011

Pilots show that CCS works:

ALSTOM

- 90 % CO2 Capture and 99% CO2 Purity is demonstrated
- Feasibility of integrated capture – transport – storage established on a power plant
- Energy penalty < 20%, and soon at 15%
- Solid base for design and cost control
- Oxy and Post have good potential



Source: Alstom

Costs of CCS - PJ - 25 May 2011 - P 12

Results (1)

ALSTOM

Hard coal

- Costs of electricity generated (*):
  - €84/MWhr in 2015 = 70% more than the same plant without CCS
  - €73/MWhr in 2030 = 45% more than the same plant without CCS
- The additional costs (*) are equivalent to:
  - in 2015, €54 per tonne of CO2 avoided
  - In 2030, €37 per tonne
- Oxy and post-combustion technologies deliver the same performance by 2030
- Energy penalty of 15-16 % can be realistically targeted by 2030
- Lower total cost of electricity than solar, geothermal and off-shore wind
- Competitive with nuclear, on-shore wind and large hydro
- Coal with CCS is cheaper than onshore wind as well when additional system costs for intermittent renewables are counted

Costs of CCS - PJ - 25 May 2011 - P 13

Results (2)

ALSTOM

Gas

- Costs of electricity generated (CoE):
  - €65/MWhr in 2015 = 50% more than the same plant without CCS
  - €55/MWhr in 2030 = 30% more than the same plant without CCS
- The additional costs are equivalent to:
  - in 2015, €74 per tonne of CO2 avoided
  - In 2030, €49 per tonne
- Energy penalty of 15-16 % can be realistically targeted by 2030
- Lower total cost of electricity than wind (off- and on-shore), solar and geothermal
- Competitive with nuclear and large hydro

Costs of CCS - PJ - 25 May 2011 - P 14

Results (3)

ALSTOM

Overall

- CCS on gas or coal is cost competitive with wind even now, before cost reductions from learning effects. With the same FIT given to wind, CCS will be "commercially viable" as soon as demonstrated in 2015.
- Learning effects will increase CCS competitiveness against more mature renewables.
- A target of CO2 avoided cost in the range of €30-35/t is realistic by 2030 for coal.
- CoE uplift in 2030 will be 45% for coal and 30% for gas: CCS on gas is thus commercially viable and cheaper than CCS on coal.
- At a carbon price of €43 in 2025, coal CCS will be commercially viable without FIT. Gas, at a price of €54 in 2026.
- The main determinant of CoE remains the fuel price, especially for gas.

Costs of CCS - PJ - 25 May 2011 - P 15

CCS essential and affordable on both gas and coal

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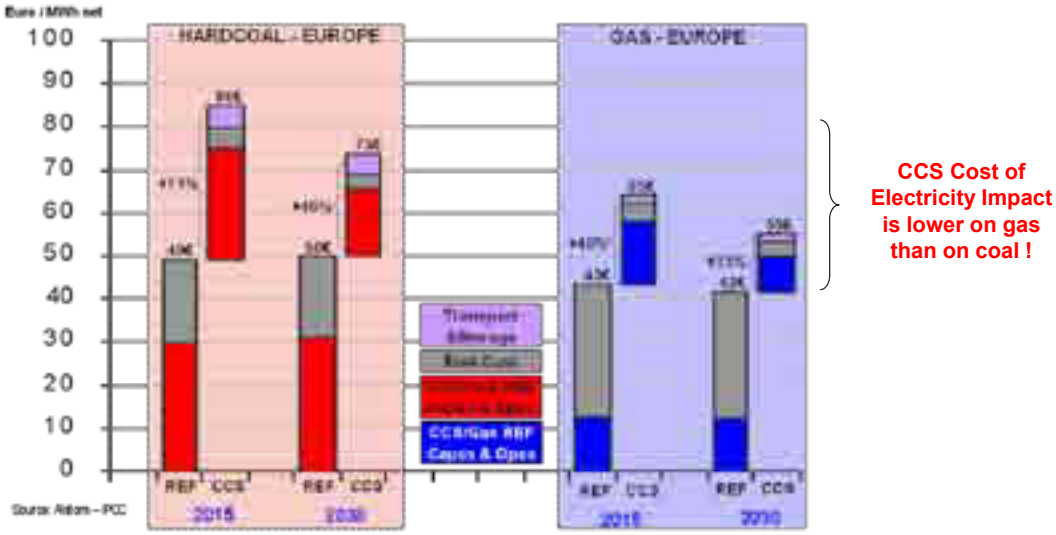

Cost increase <50% by 2030 for both Coal and Gas
Cost of CO2 avoided: 37 €/t for coal and 49 €/t for gas in 2030

Costs of CCS - PJ - 25 May 2011 - P 16

Coal with CCS

ALSTOM

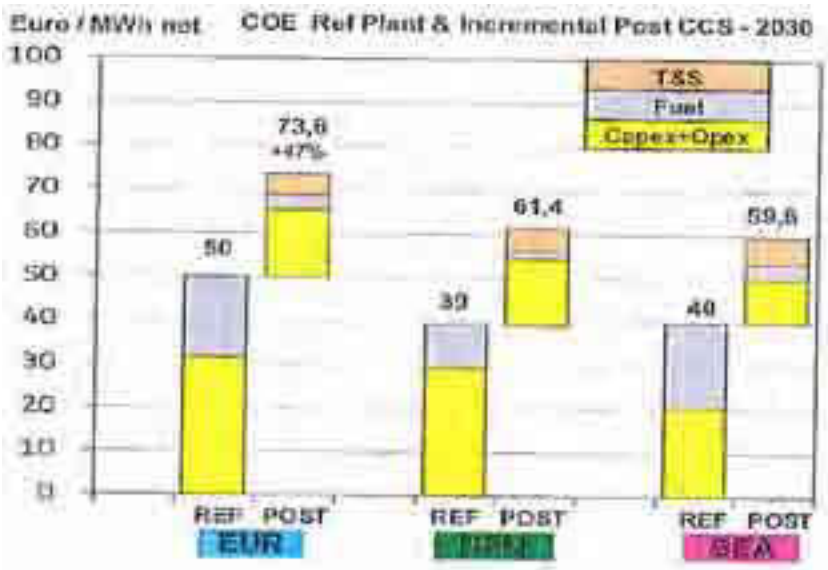

Figure 4: Post. Fuel Capex & Opex contribution in the CoE

Costs of CCS - PJ - 25 May 2011 - P 17

Gas with CCS

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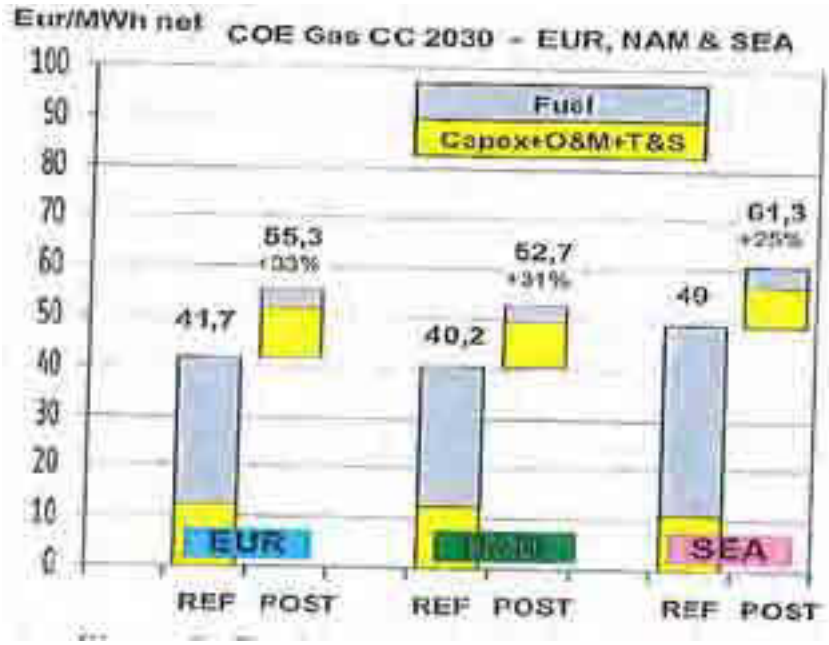


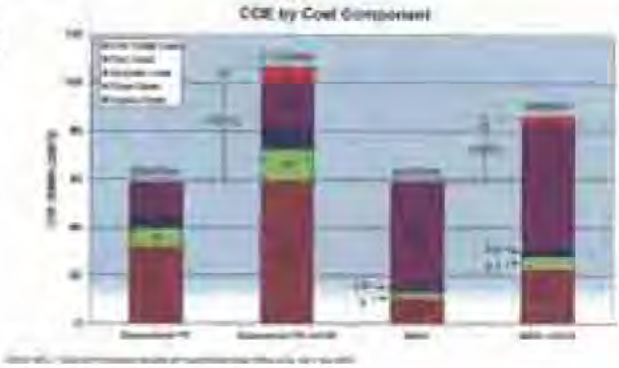
Costs of CCS - PJ - 25 May 2011 - P 18

10:30–Noon Session

CCS Cost Study - U.S. Implications

ALSTOM

- NETL analysis shows some similarities to Alstom findings
- Alstom findings shared with key U.S. Stakeholders
  Customers, Congress, DOE, EPRI
- Alstom planning U.S and Asia studies - Fall 2011

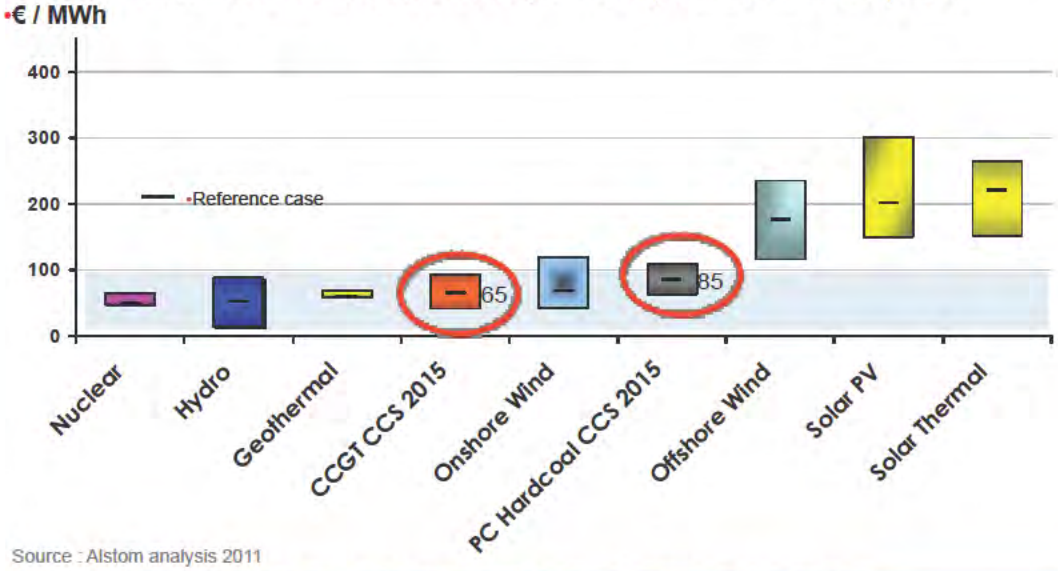


Alstom in the U.S. - P 25 | © Alstom 2011

Costs of decarbonised power compared

ALSTOM

•CoE - Low Carbon technologies Europe in 2011-2016 period

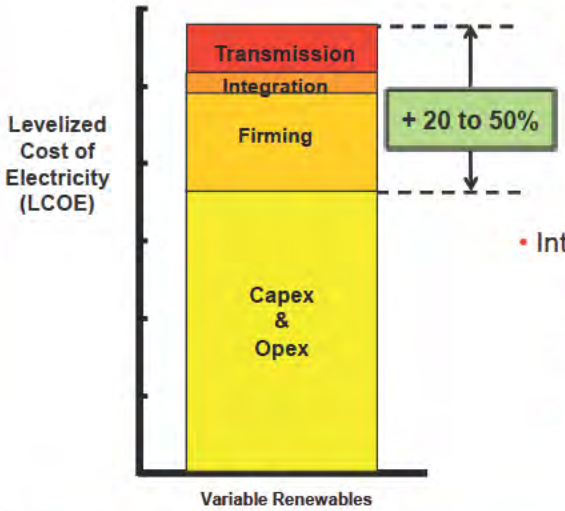


Source : Alstom analysis 2011

CCS on Coal and Gas are competitive

Cost Penalty for intermittent sources

ALSTOM



- Firming Costs :
  - Back-up capacity & storage
  - CO2 emissions from back-up
  - Installed base cost impact on flexibility, maintenance, and lower utilisation rate
- Intermittent Cost Penalty :
  - Increases with penetration
  - Is highly dependent on regional grid configuration
  - Is highly dependent on installed capacity base and reserve margin composition

Source: Alstom, based on IHS- CERA and IEA studies

Intermittent power generation costs must be taken into account.

Costs of CCS - PJ - 25 May 2011 - P 21

Key Messages

ALSTOM

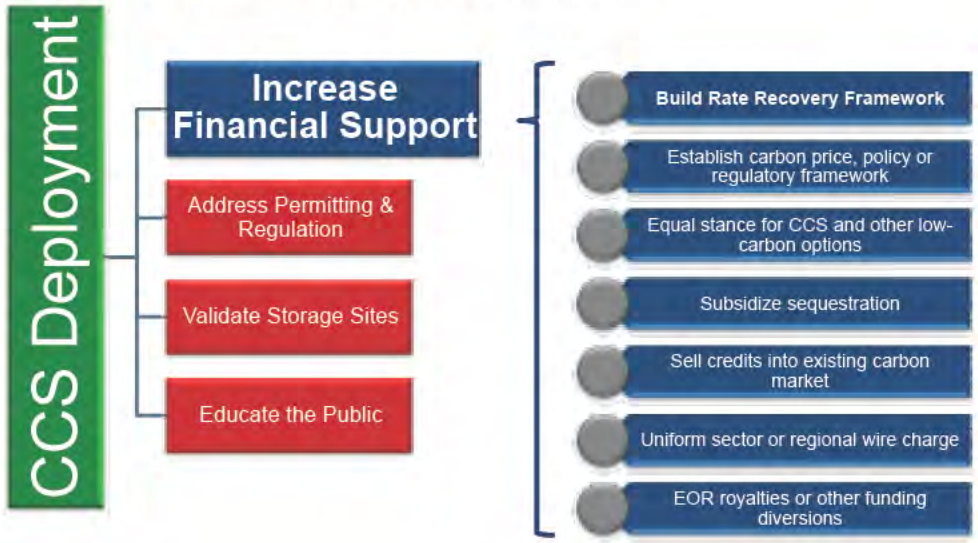
- CCS essential <u>and</u> affordable on both gas and coal.
- Fossil power with CCS costs no more than most renewables.
- CCS is an essential part of the portfolio of solutions needed to decarbonise power generation.
- Alstom is ready and well positioned for immediate scale-up, and to provide for a commercial offer by 2015.
- CCS deployment still faces significant challenges world-wide:
  - Financial support
  - Regulation/Permitting
  - Storage sites validation
  - Public awareness

12

How Do We Get There

ALSTOM

Address the Challenges to CCS Deployment



Alstom in the U.S. - P 29| © Alstom 2011

What Needs To Be Done

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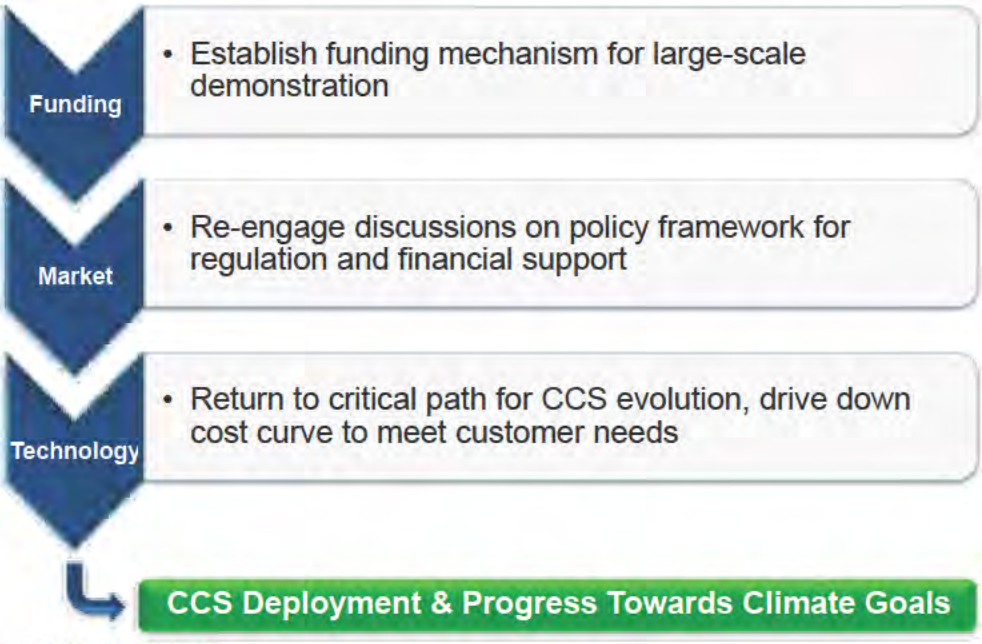

Alstom in the U.S. - P 30 | © Alstom 2011

Thank You

ALSTOM

The Alumni Professor of Environmental Engineering and Science

Professor, Engineering and Public Policy and Mechanical Engineering, Carnegie Mellon University

EDWARD RUBIN is a professor in the Departments of Engineering and Public Policy, and Mechanical Engineering, at Carnegie Mellon University. He is the Alumni Chair Professor of Environmental Engineering and Science, and was founding director of the university's Center for Energy and Environmental Studies and the Environmental Institute. He was coordinating lead author of the IPCC's 2005 Special Report on Carbon Dioxide Capture and Storage, and recently served on the US National Academies study of "America's Climate Choices," as well as the high-level CCS advisory committees of the State of California and the Province of Alberta, Canada. He is the author of over 200 technical publications and recipient of the Lyman A. Ripperton Award and the Distinguished Professor of Engineering Award. Dr. Rubin received his bachelor's degree in mechanical engineering from the City College of New York and his Ph.D. degree from Stanford University.

The Cost of CCS for Natural Gas-Fired Power Plants

Edward S. Rubin
Department of Engineering and Public Policy
Carnegie Mellon University
Pittsburgh, Pennsylvania

Presentation to the
Natural Gas CCS Forum
Washington, DC

November 4, 2011

Some Questions of Interest

- What is the estimated cost of CCS for NGCC power plants?
- What is the uncertainty/variability in current cost estimates?
- What factors contribute most to CCS cost uncertainty?
- What carbon price or tax is needed to induce CCS use on NGCC plants?

E.S. Rubin, Carnegie Mellon

Recent Studies

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Recent CCS Cost Estimates for Natural Gas-Fired Power Plants

- 2007: Rubin, Chao, Rao, *Energy Policy*
- 2007: DOE/NETL Baseline Report 2007/1281
- 2009: IEAGHG Report 2009/TR-3
- 2009: EPRI Report No 1017495
- 2009: CO_2 Capture Project
- 2010: DOE/NETL Baseline Report 2010/1397
- 2010: US Interagency Task Force on CCS
- 2010: Southern California Edison
- 2010: UK DECC, Mott MacDonald Report
- 2011: DOE/EIA AEO 2011
- 2011: IEA Working Paper
- 2011: Global CCS Institute Update

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Results of Recent Studies for U.S. NGCC Power Plants (no CCS)

Parameter	NETL Baseline Rev 1 (2007)	NETL Baseline Rev 2 (2010)	U.S.Task Force on CCS (2010)	EPRI Update (2009)		EIA AEO (2011)
Turbine class/type	7FB	7FB		7FB	7FB	*H*
Net power output (MW)	560.4	555.1		550	550	*400*
Net plant efficiency, HHV (%)	50.8	50.2		46.7	42.3	*53.1*
Capacity factor	85%	85%		80%	40%	*87%*
Cost year	2007	2007	2009	2007	2007	*2009*
Inflation rate (0%=constant $)	1.87%	3%	3%	0%	0%	
Fixed charge factor	0.164	0.105	0.150	~0.12	~0.12	
Levelization period (years)	20	30	30	30	30	*30*
NG price ($/MBtu)	6.75	6.55		7.00	7.00	
Total plant cost ($/kW)	554	584		800	800	
Total overnight cost ($/kW)		718				*1003*
First-year COE ($/MWh)		58.9				
Levelized COE ($/MWh)	**68.4**	**74.7**	**77**	**66.4**	**85.3**	*63.1*

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Results of Recent Studies for U.S. NGCC Plants with CCS

Parameter	NETL Baseline Rev 1 (2007)	NETL Baseline Rev 2 (2010)	U.S.Task Force on CCS (2010)	EPRI Update (2009)		EIA AEO (2011)
Capture system	FG+	FG+	Amine	Econamine	Econamine	
CO_2 capture efficiency	90%	90%	90%	90%	90%	
Net power output (MW)	481.9	473.6		467.5	467.5	*340*
Net plant efficiency, HHV (%)	43.7	42.8		39.7	35.9	*45.4*
Capacity factor	85%	85%		80%	40%	*87%*
Fixed charge factor	0.175	0.111	0.157	~0.12	~0.12	
CCS T&S cost ($/MWh)	2.9	3.2		4.1	4.5	
CCS T&S cost ($/tonne CO_2)				10	10	
Total plant cost ($/kW)	1172	1226		1370	1370	
Total overnight cost ($/kW)		1497				*2060*
First-year COE ($/MWh)		85.9				
Levelized COE ($/MWh)	**97.4**	**108.9**	**121**	**91.2**	**121.1**	*89.3*

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Results of Recent NGCC Studies: Added Cost for CCS

Cost Parameter (levelized 2007$)	NETL Baseline Rev 1 (2007)	NETL Baseline Rev 2 (2010)	US Task Force on CCS (2010)	EPRI Update (2009)		EIA AEO (2011)
Added COE for CCS ($/MWh)	29	34	44*	25	36	26*
Cost of CO_2 Avoided ($/tonne CO_2)	92	106	115*	74	95	n/a

*2009 dollars

These results reflect different assumptions about key technical and economic parameters, especially:

- Plant efficiency
- Capacity factor
- Gas price
- Capital cost
- Inflation rate
- Fixed charge factor

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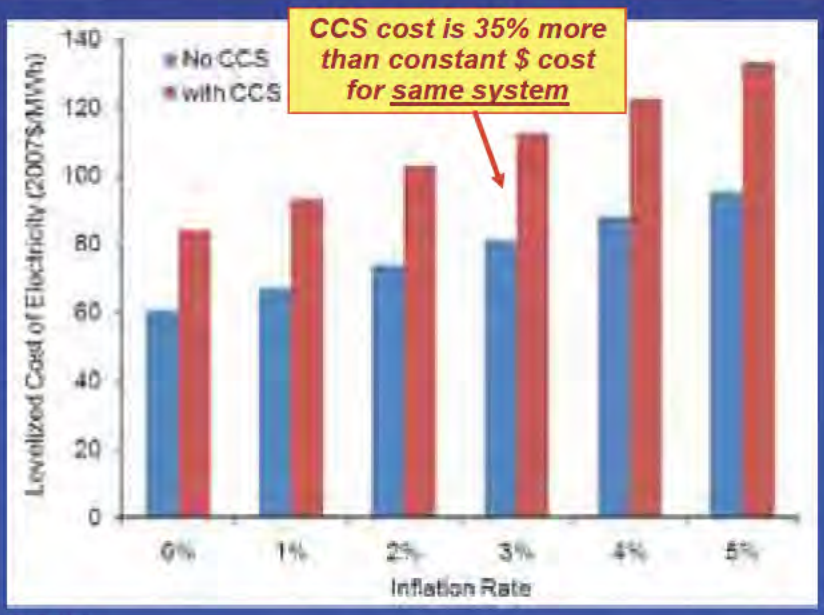
Assumed Inflation Rate Alone has a Major Effect on Reported Costs



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U.S. Average Capacity Factors for NGCC Plants, 1998-2009

Year	Avg. CF
1998	34.2
1999	33.2
2000	37.1
2001	35.7
2002	38.2
2003	33.5
2004	35.5
2005	36.8
2006	38.8
2007	42.0
2008	40.6
2009	42.5

Source: EIA, 2011. Values thru 2002 include all NG-fired plants.

Actual values currently are <u>much</u> <u>lower</u> than the levelized (baseload plant) values of 80-87% assumed in most recent studies

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A more systematic approach

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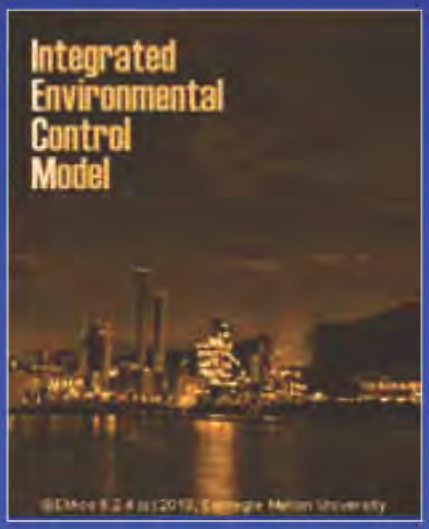
10:30–Noon Session

The IECM:
A power plant performance and cost model

- A desktop/laptop computer model developed for DOE/NETL; free and available at: **www.iecm-online.com**
- Provides systematic estimates of performance, emissions, costs and uncertainties using user-specified designs and parameter values for:
  - PC, IGCC and NGCC plants
  - All flue/fuel gas treatment systems
  - CO_2 capture and storage options (pre- and post-combustion, oxy-combustion; transport, storage)



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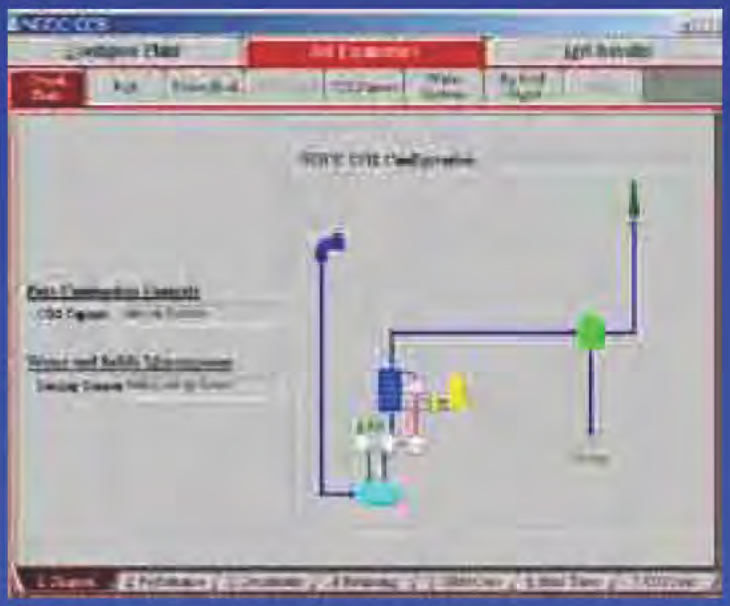
Configure Plant:
NGCC Plant with CCS



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Set Parameters:
Example Input Parameters

Performance Parameters

Capital Cost Parameters

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Get Results:
Illustrative Results (Capture Unit)

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Base Case Assumptions & Results

Parameter	*Case 1:* No CCS	*Case 2:* With CCS
Gas turbine model	GE 7FB	GE 7FB
Natural gas composition	NETL	NETL
CCS system	none	FG+ /saline aq.
CO_2 capture efficiency	0%	90%
Net power output (MW)	527	449
Net plant efficiency, HHV (%)	50.0	42.6
Capacity factor (%)	75	75
Cost basis	Constant 2007$	Constant 2007 $
Fixed charge factor (fraction)	0.113	0.113
Natural gas cost ($/MBtu)	6.55	6.55
Operating labor rate ($/hr)	34.65	34.65
Total capital requirement ($/kW)	**760**	**1336**
LCOE (mills/kWh)	**60.8**	**84.2**

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Sensitivity Analysis

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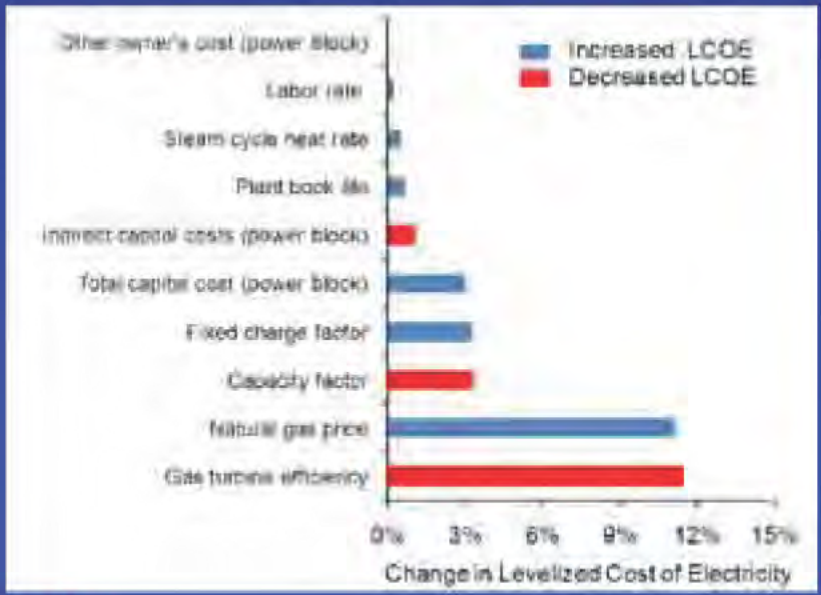
Effect on LCOE of a 15% Increase in Nominal Parameter Value



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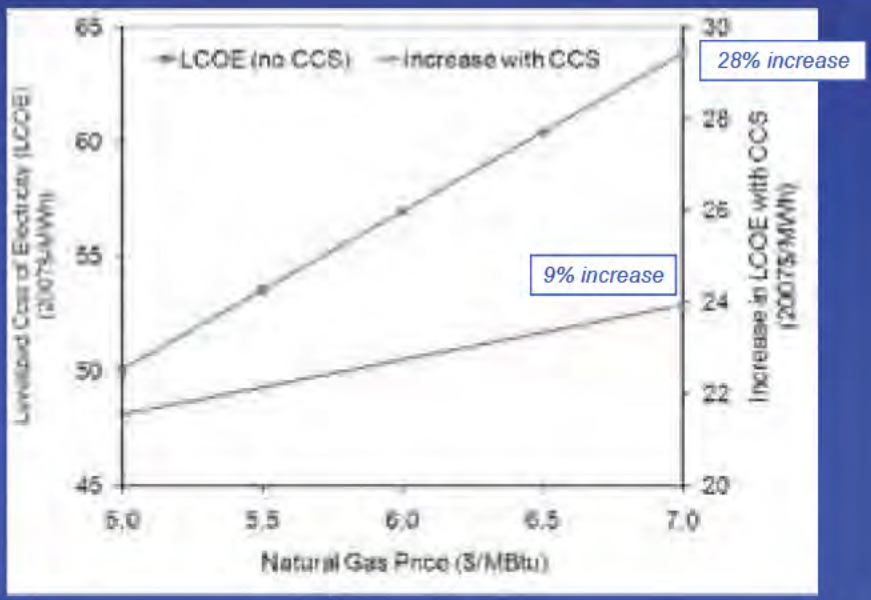
Effect of Natural Gas Price on LCOE and CCS Cost



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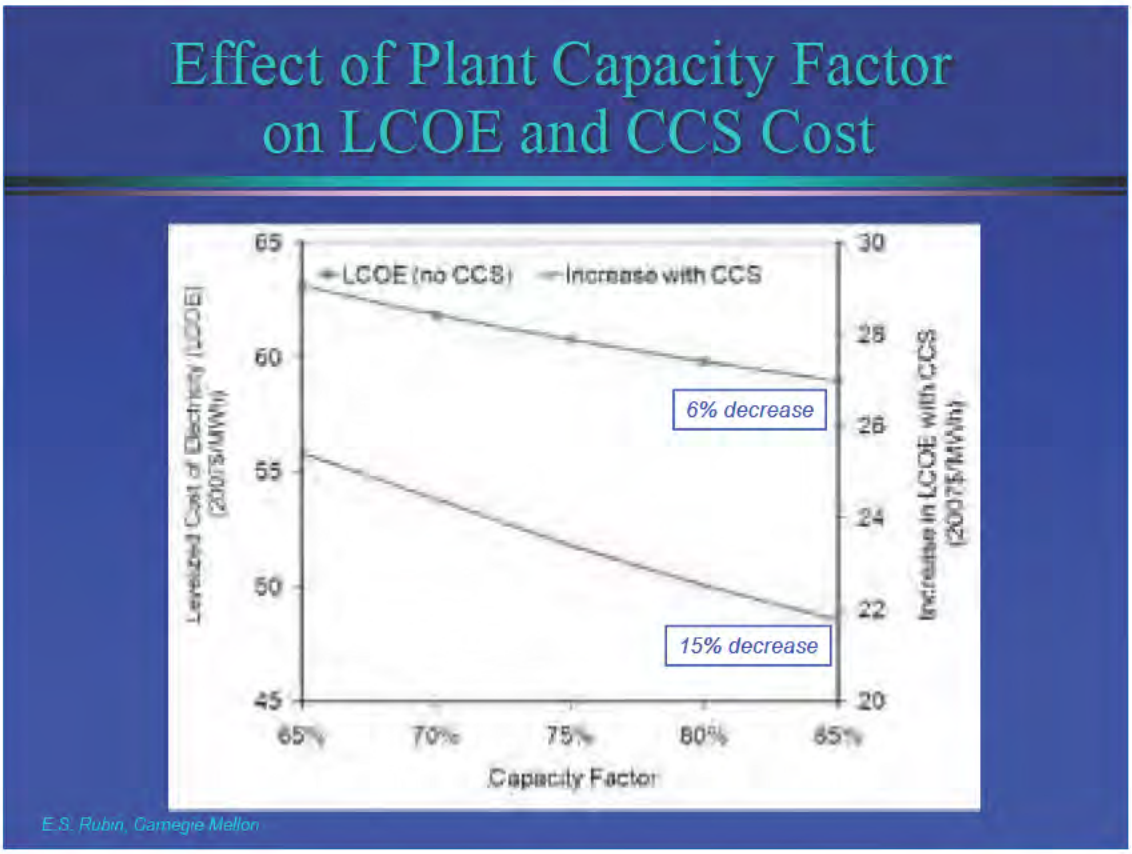
10:30–Noon Session


Effect of Plant Capacity Factor on LCOE and CCS Cost
LCOE (no CCS)
Increase with CCS
6% decrease
15% decrease
Levelized Cost of Electricity (LCOE) (2007$/MWh)
Increase in LCOE with CCS (2007$/MWh)
65
60
55
50
45
30
28
26
24
22
20
65%
70%
75%
80%
85%
Capacity Factor
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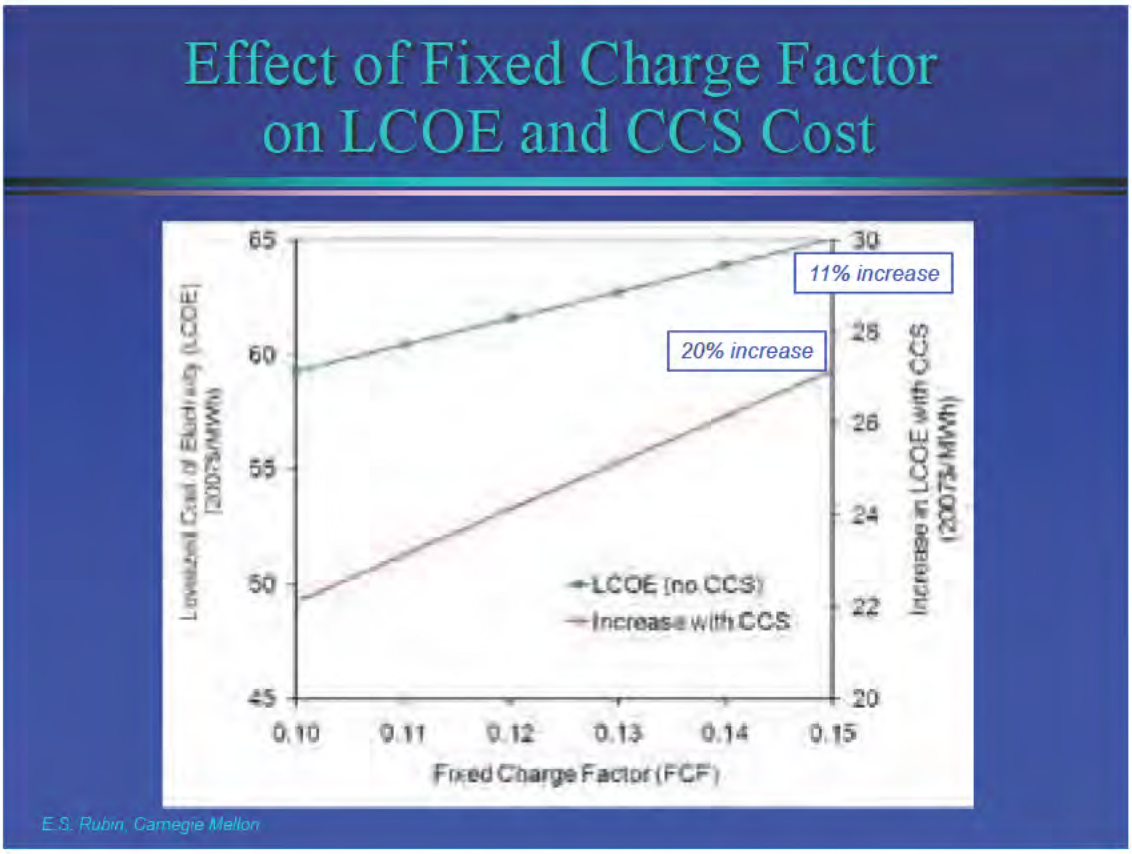
Effect of Fixed Charge Factor on LCOE and CCS Cost
11% increase
20% increase
LCOE (no CCS)
Increase with CCS
Levelized Cost of Electricity (LCOE) (2007$/MWh)
Increase in LCOE with CCS (2007$/MWh)
65
60
55
50
45
30
28
26
24
22
20
0.10
0.11
0.12
0.13
0.14
0.15
Fixed Charge Factor (FCF)
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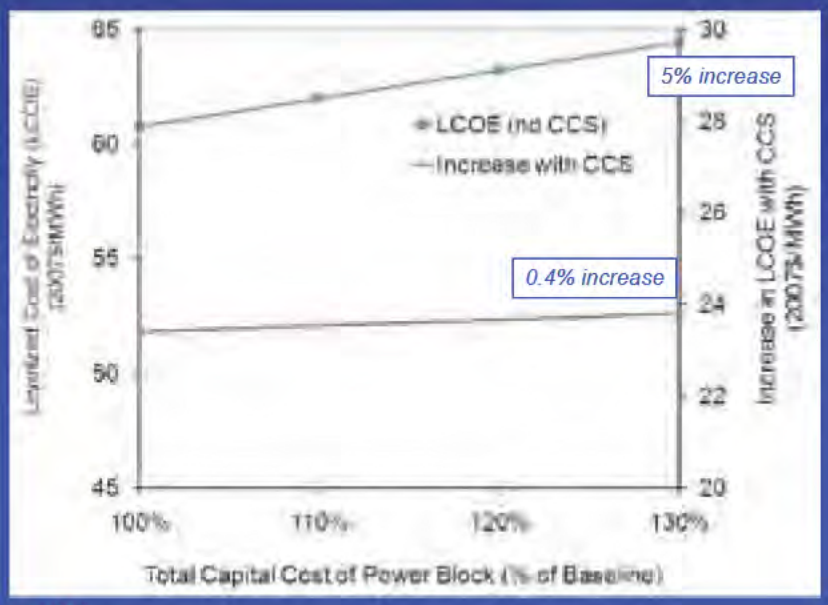
Effect of Power Block Capital Cost on LCOE and CCS Cost



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Probabilistic Analysis

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10:30–Noon Session

Assumed Uncertainty/Variability for NGCC Plant Parameters

Uncertainty Source	Parameter	Nominal Value	Min. Value	Max. Value	Distribution Function
Power block capital cost	Direct capital cost (% of baseline)	100	100	130	Uniform
	Indirect capital costs (total % of direct)	45.7	20	70	Uniform
	Misc. owner's cost (% total investment)	2	0	10	Uniform
Financing	Fixed charge factor *high risk cases:*	0.113 *0.143*	0.100 *0.130*	0.150 *0.180*	Uniform
O&M costs	Natural gas price ($/MBtu)	6.55	5.00	7.50	Uniform
	Labor rate ($/hr)	34.65	30	40	Uniform
Plant utilization	Capacity factor (levelized)	75%	65%	85%	Uniform

Covers ranges in other recent cost studies

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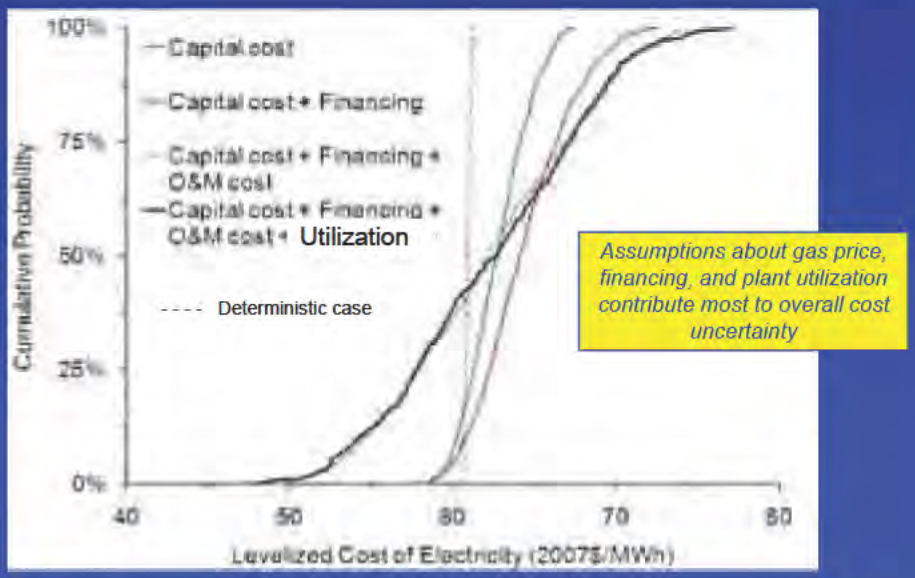
Probabilistic Results for NGCC Reference Plant with no CCS



Assumptions about gas price, financing, and plant utilization contribute most to overall cost uncertainty

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Uncertainty Distributions for CO_2 Capture System Parameters

Parameter	Units	Nominal Value	Distribution Function
ID fan efficiency	%	75	uniform (70,75)
Solvent pumping head	psia	30	triangular (5,30,36)
Pump efficiency	%	75	uniform (70,75)
Regeneration heat reqm't.	Btu/lb CO_2	1712	uniform (1290, 2150)
System cooling duty	t H_2O/ t CO_2	123	triangular (67, 123,162)
Nominal sorbent loss	lb/ton CO_2	0.6	triangular (0.5, 0.6,3.1)
Captured CO_2 purity	vol %	99.5	uniform (99.0, 99.8)
CO_2 product pressure	psig	2000	uniform (1800, 2200)
CO_2 compressor efficiency	%	80	uniform (75,85)
Total indirect capital costs	%	37.0	uniform (20,70)
Miscellaneous owner's costs	%	2	uniform (0,10)

Some CCS cases assume a "high risk" premium of 3 percentage point increase in FCF for first of a kind (FOAK) plants (compared to "low risk" N^{th} of kind, NOAK)

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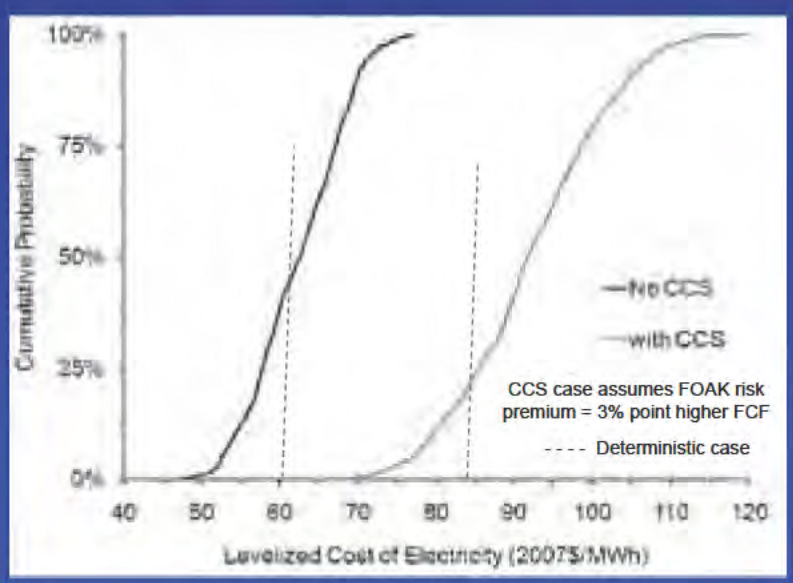
Probabilistic Results for LCOE with and without CCS



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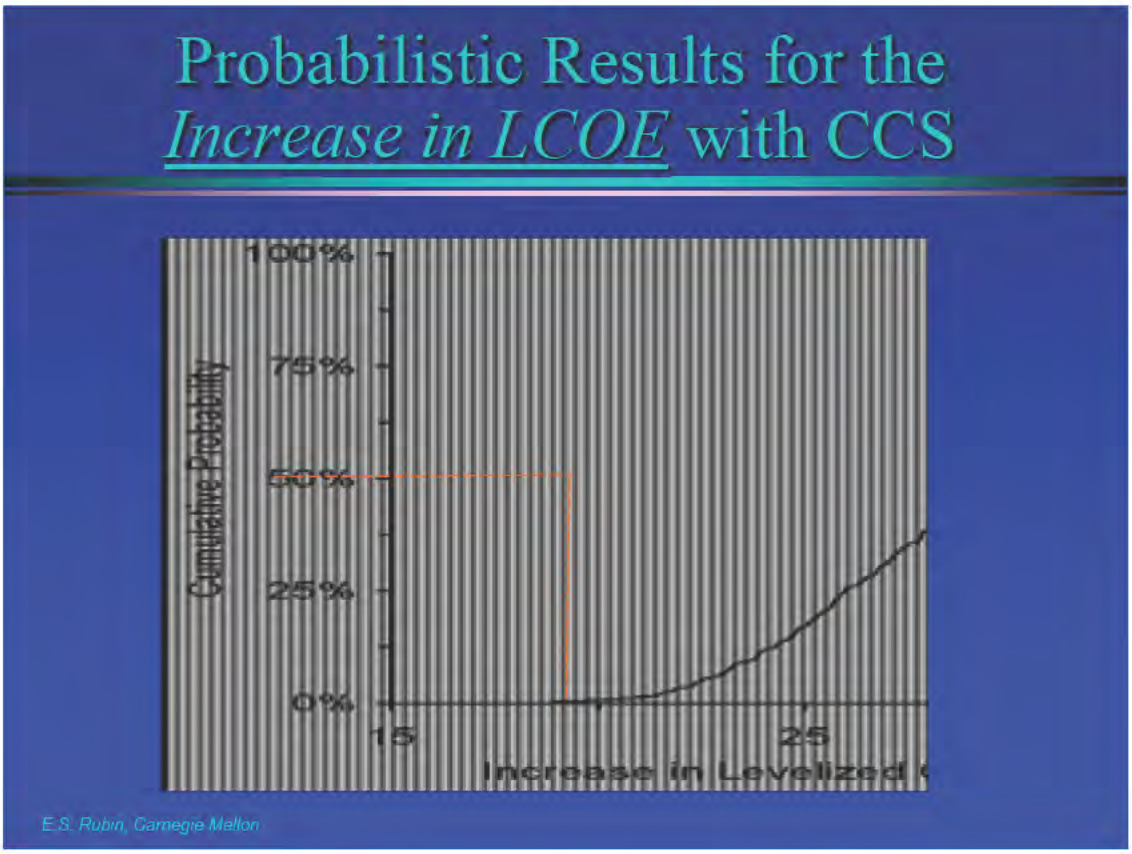
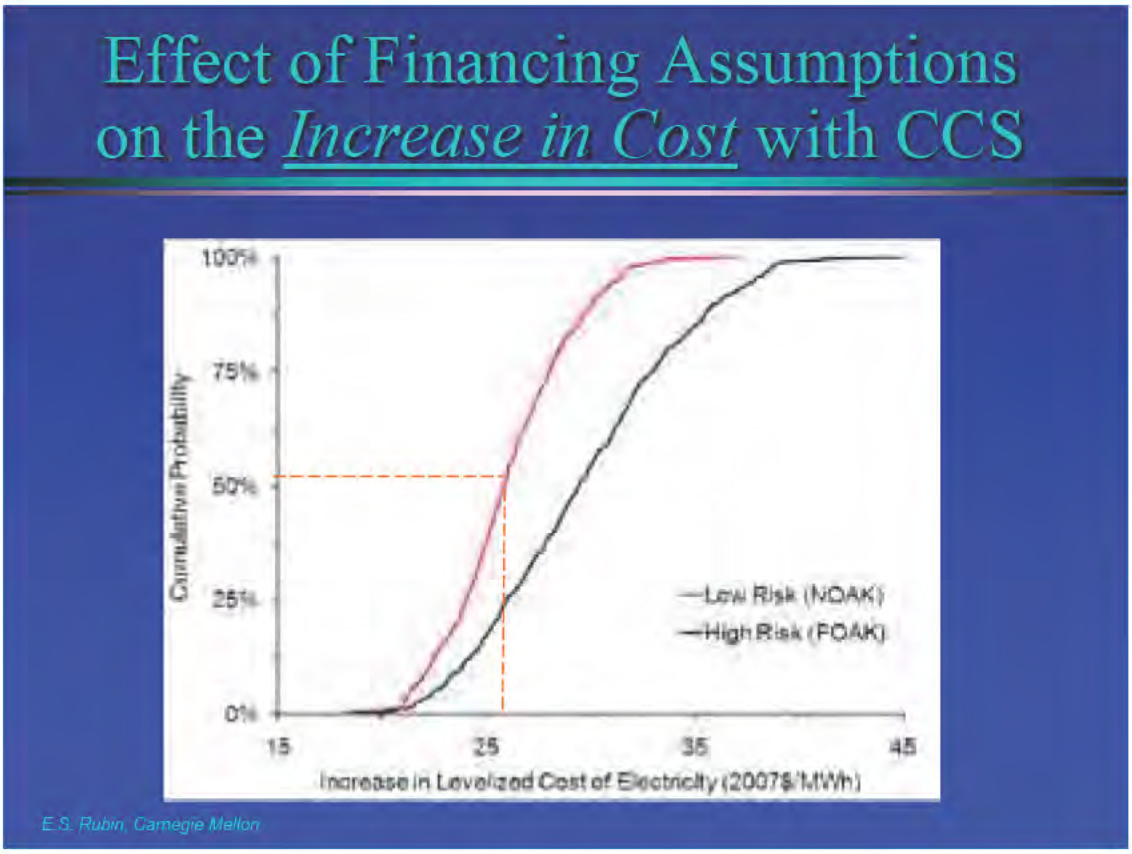
10:30–Noon Session


Probabilistic Results for the
Increase in LCOE with CCS
100%
75%
50%
25%
0%
Cumulative Probability
15
25
Increase in Levelized
E.S. Rubin, Carnegie Mellon


Effect of Financing Assumptions
on the Increase in Cost with CCS
100%
75%
50%
25%
0%
Cumulative Probability
Low Risk (NOAK)
High Risk (FOAK)
15
25
35
45
Increase in Levelized Cost of Electricity (2007$/MWh)
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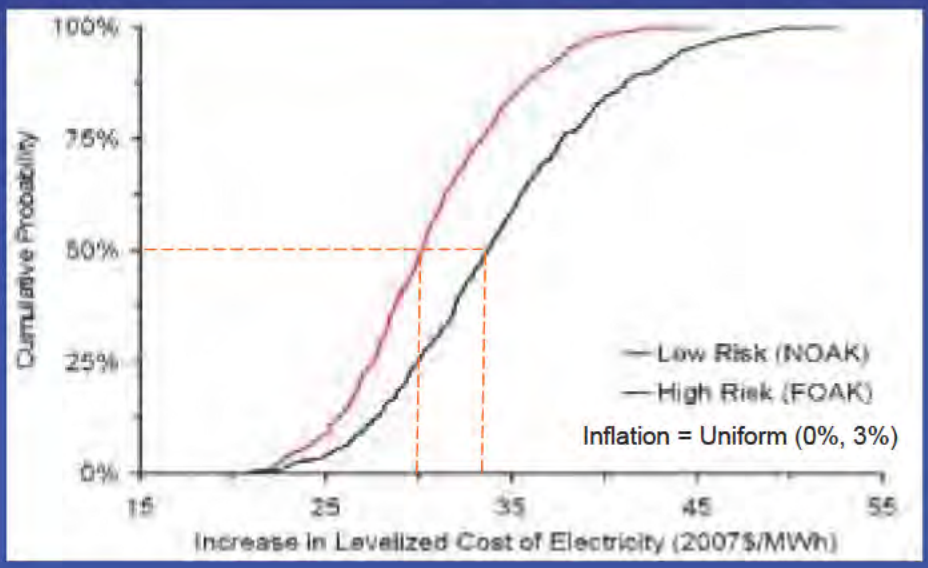
Effect of Inflation Assumption on the *Increase in Cost* with CCS



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What carbon price is needed to encourage CCS?

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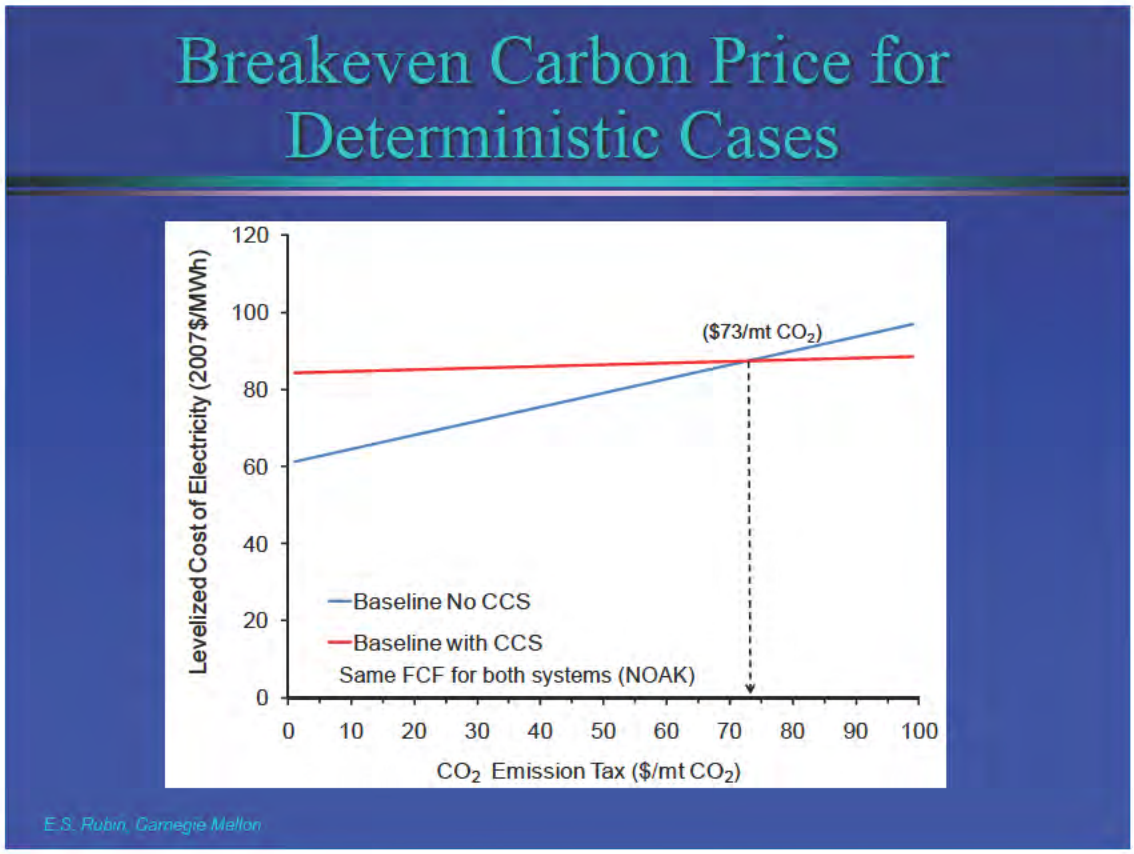
10:30–Noon Session


Breakeven Carbon Price for Deterministic Cases
Levelized Cost of Electricity (2007$/MWh)
120
100
80
60
40
20
0
($73/mt CO2)
Baseline No CCS
Baseline with CCS
Same FCF for both systems (NOAK)
0 10 20 30 40 50 60 70 80 90 100
CO2 Emission Tax ($/mt CO2)
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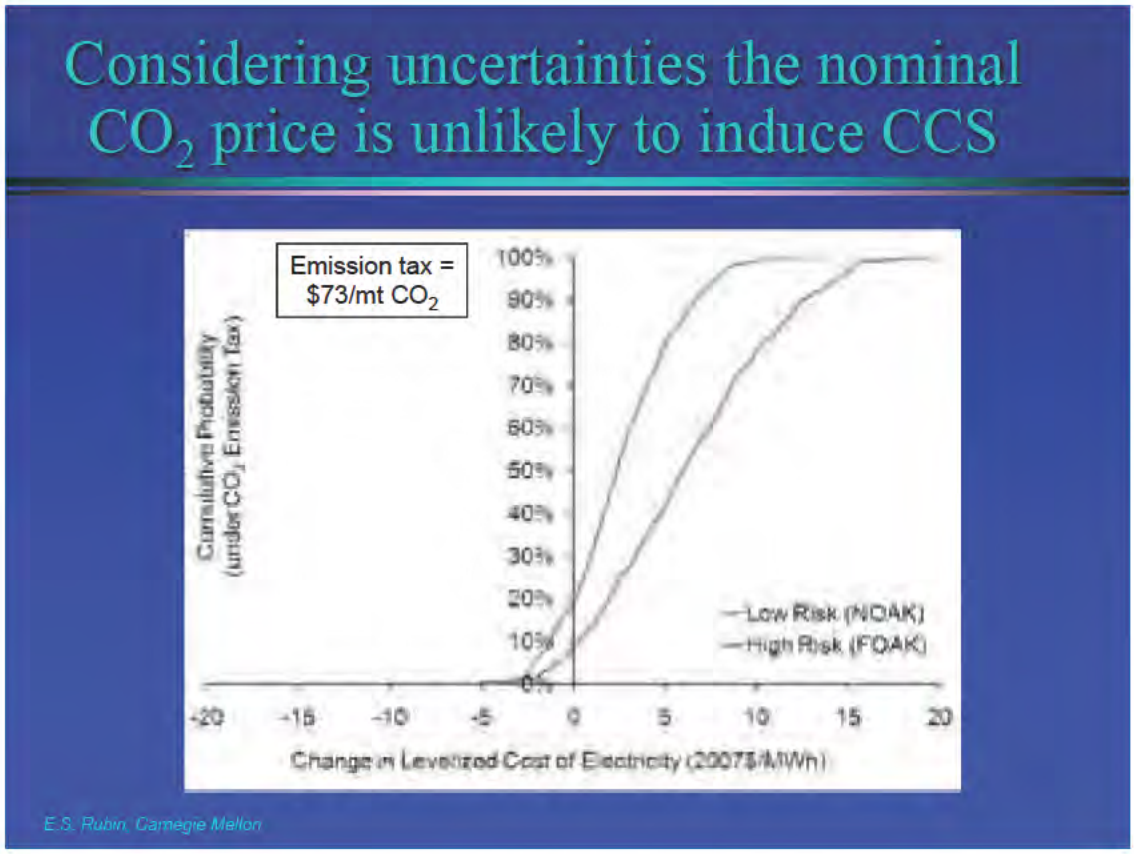
Considering uncertainties the nominal CO2 price is unlikely to induce CCS
Emission tax = $73/mt CO2
Cumulative Probability (under CO2 Emission Tax)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Low Risk (NOAK)
High Risk (FOAK)
-20 -15 -10 -5 0 5 10 15 20
Change in Levelized Cost of Electricity (2007$/MWh)
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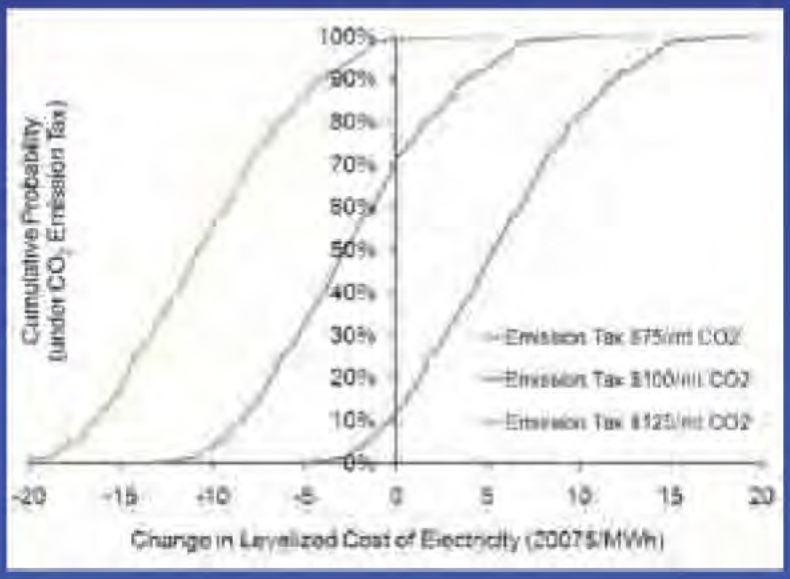
Likelihood of adopting CCS for different CO_2 emission charges



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Conclusions *(1)*

- Adding current CCS to a new baseload NGCC power plant is likely to increase the LCOE by about $20–35/MWh (in constant dollars), or about $25–45/MWh in current dollars, based on current technology.
- Uncertainties in the terms of plant financing, the future price of natural gas, and the degree of plant utilization over its lifetime contribute most to the overall variability of current cost CCS estimates.

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Conclusions *(2)*

- Because of cost uncertainties, a policy intended to encourage CCS at NGCC plants solely via an emissions tax or a carbon price requires a higher than average price to be effective.
- The levelized cost of NGCC plants with or without CCS will be higher than the values shown here if NGCC plants fail to operate under baseload conditions (as is currently the case).

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*Thank You**

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**Special thanks to Dr. Haibo Zhai, co-author of this study.*

1:00–2:30 Session

Demonstrating CCS

Policy Director,
Great Plains Institute

BRAD CRABTREE has been Policy Director of the Great Plains Institute since 2002. Brad co-directs the National Enhanced Oil Recovery Initiative, an energy security project of the Institute convened in partnership with the Pew Center on Global Climate Change to increase domestic oil production using carbon dioxide captured from industrial sources. He recently facilitated the Midwestern Greenhouse Gas Reduction Accord Advisory Group established by six governors and the Manitoba premier, and he coordinated energy advisory groups for the Midwestern Governors Association. Prior to the Institute, Brad was project director at the Consensus Council, managing regional flood mitigation and resource management projects. His background also includes environmental policy and project development work in Washington, DC and Brazil and field research in Borneo. Brad raises sheep and cattle with his wife and daughter in North Dakota, where he was a statewide candidate for Public Service Commissioner in 2010. A graduate of the Georgetown School of Foreign Service, he has an MA in history from Johns Hopkins University.

National Enhanced Oil Recovery Initiative

Accelerating Commercial Deployment of CCS:

Developing Incentives to Expand Anthropogenic CO2 Supply for Enhanced Oil Recovery Commercial

Brad Crabtree
Great Plains Institute

From a Bridge to a Destination: Gas-Fired Power after 2020
November 4th, 2011
Washington, DC

Great Plains Institute
Working on tomorrow's energy solutions with today's leaders

National Enhanced Oil Recovery Initiative

Background

Commercial carbon management is here and now—and bigger than most realize—thanks to CO2 Enhanced Oil Recovery:

- 40 years of commercial operational experience (began in West Texas in 1972).
- Nearly 300,000 barrels of oil produced daily, or about 6 percent of U.S. domestic production.
- U.S. EOR industry manages pipeline transport and injection of roughly 65 million tons of CO2 annually—profitably and without serious reported injuries, accidents or environmental harm.

Some of that CO2 to produce oil already comes from industrial sources . . .

Current CO_2 Supply for EOR

Source Type (Location)	CO_2 Supply (Mt/year)	
	Natural	*Anthropogenic*
Colorado, New Mexico (Geologic)	33	-
Texas (Gas Processing)	-	6.4
Wyoming (Gas Processing)	-	6.6
Mississippi (Geologic)	22	-
Oklahoma (Fertilizer Plant)	-	0.7
Michigan (Gas Processing)	-	0.3
North Dakota (Coal Gasification)	-	3
Total	**55**	**17**

U.S. Department of Energy (2011), *Improving Domestic Energy Security and Lowering CO_2 Emissions with "Next Generation" CO_2-Enhanced Oil Recovery (CO_2-EOR)*, DOE/NETL-2011/1504, citing Advanced Resources International (2011).

3

And the potential is truly vast . . .

NETL/ARI Projected CO_2-EOR Resources

	Incremental Technically Recoverable Oil (Billion Barrels)		Incremental Economically Recoverable Oil (Billion Barrels)	
	Best Practices	*Next Generation*	*Best Practices*	*Next Generation*
Lower 48 Onshore	55.7	104.4	24.3	60.3
Total	61.5	136.6	29.6	67.2

[1] U.S. Department of Energy (2011), *Improving Domestic Energy Security and Lowering CO_2 Emissions with "Next Generation" CO_2-Enhanced Oil Recovery (CO_2-EOR)*, DOE/NETL-2011/1504.
[2]Incremental technically recoverable after subtracting 2.3 billion barrels already being developed by CO_2-EOR.
[3]"Best practices" assumes "state of the art" technology characteristics used in DOE's 2008 NETL study, *Storing CO_2 with Enhanced Oil Recovery*, Report DOE/NETL-402/1312/02-07-08 and DOE NETL (2011).
[4]"Next generation" assumes technology characteristics used in DOE's 2009 NETL study, *Storing CO_2 and Producing Domestic Crude Oil with Next Generation CO_2-EOR Technology*, Report DOE/NETL-2009/1350 and DOE NETL (2011).
[5]Estimates for incremental economically recoverable oil assumes an oil price of $85/bbl , a CO_2 price of $40/ton and a project rate of return of at least 20%.

4

But, we need more CO2 . . . and natural gas has a major role.

EIA's Projected CO_2 Supply for EOR (tons annually)

	Natural Gas Processing	Hydrogen	Refineries (Hydrogen)	Ammonia	Ethanol	Cement	Power Plants
Gulf Coast	6,031,746	-	6,031,746	4,126,984	-	4,550,265	207,936,508
West Coast	2,119,402	-	4,928,635	-	211,640	2,589,683	40,000,000
Southwest	-	-	-	-	3,557,884	1,313,344	-
Rocky Mountains	633,921	-	2,288,423	158,730	1,216,931	1,851,852	153,808,524
Northern Great Plains	317,460	-	946,561	-	476,190	131,790	3,174,603
Midcontinent	-	-	52,915	-	9,259,259	2,519,683	39,788,360
East Coast	1,216,570	116,730	899,471	-	2,751,323	4,971,540	688,772,487

[1]U.S. Energy Information Administration, Office of Energy Analysis (2011). Assumptions to the Annual Energy Outlook, Oil & Gas Supply Module.
[2]EIA notes that technology and market constraints prevent the total volumes of CO_2 from becoming immediately available.

5

Natural gas CO2 supply comes in at both ends of the cost spectrum . . .

EIA's CO2 Capture & Transport Cost Assumptions ($/ton)

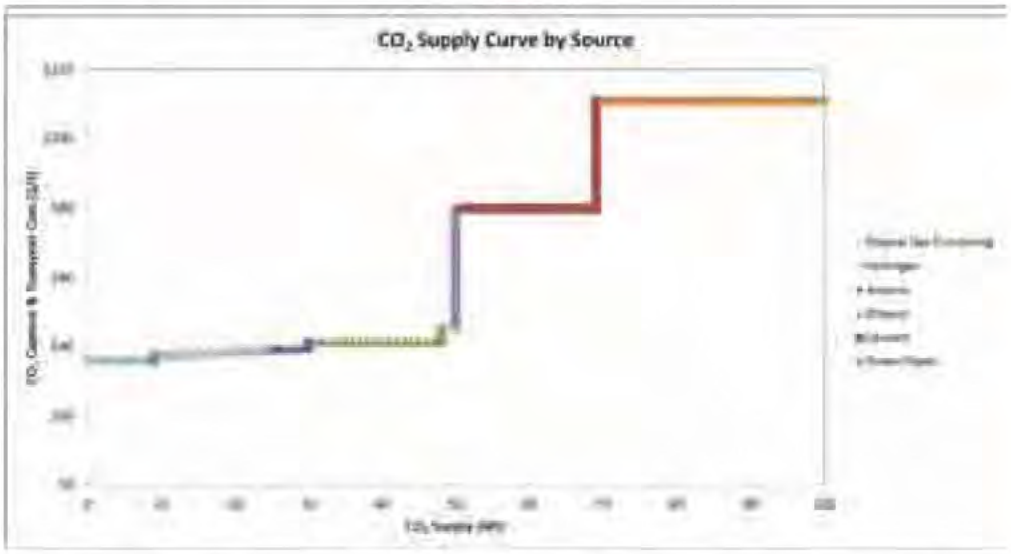
	Natural Gas Processing	Hydrogen	Refineries (Hydrogen)	Ammonia	Ethanol	Cement	Power Plants
Gulf Coast	$36.29	$36.63	$36.63	$39.69	$42.15	$81.08	$112.64
West Coast	$36.29	$37.99	$37.99	$39.69	$42.15	$81.08	$112.64
Southwest	$36.29	$38.38	$38.18	$39.69	$42.15	$81.08	$112.64
Rocky Mountains	$36.29	$38.37	$38.37	$39.69	$42.15	$81.08	$112.64
Northern Great Plains	$36.29	$38.75	$38.75	$39.69	$42.15	$81.08	$112.64
Midcontinent	$36.29	$39.12	$39.12	$39.69	$42.15	$81.08	$112.64
East Coast	$36.29	$46.12	$46.12	$39.69	$42.15	$81.08	$112.64

U.S. Energy Information Administration, Office of Energy Analysis (2011). Assumptions to the Annual Energy Outlook, Oil & Gas Supply Module.

6

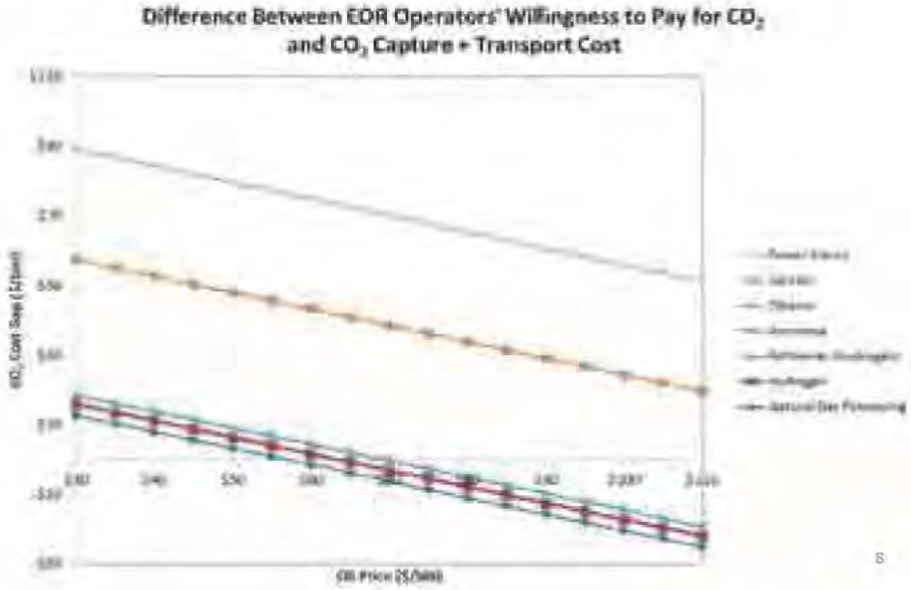
1:00–2:30 PM Session

Natural gas processing has and will continue to be an early target for CO2 supply to the EOR industry . . .



7

CO2 from post-combustion capture off natural gas power generation can come later, but only with significant incentives to lower capture costs. . .



8

National Enhanced Oil Recovery Initiative

Overview of the Initiative

Collaborative national policy and outreach effort: oil and gas companies, industries supplying CO2; state officials, legislators and regulators; and state and national environmental NGOs.

Mission: Accelerate commercial deployment of enhanced oil recovery using CO2 from fossil, renewable and industrial sources**.**

Convening organizations: Pew Center on Global Climate Change and Great Plains Institute.

National Enhanced Oil Recovery Initiative

Overview of the Initiative

Who's Involved

Oil and Gas
- Chaparral Energy
- Chevron Corporation
- Continental Resources
- Core Energy
- Denbury Resources
- Encana
- Occidental Petroleum

Coal and Coal-Based Generation
- Arch Coal
- Basin Electric Power Cooperative
- Leucadia
- Southern Company
- Summit Power Group
- Tenaska Energy

Industrial Suppliers of CO2/Technology Vendors
- Air Products
- Archer Daniels Midland
- GE Energy

Environmental NGOs
- Clean Air Task Force
- Natural Resources Defense Council
- Ohio Environmental Council
- Wyoming Outdoor Council

Labor
- AFL-CIO
- United Transportation Union

Other Institutions
- Enhanced Oil Recovery Institute (University of WY)
- Interstate Oil and Gas Compact Commission
- North American Carbon Capture and Storage Association
- Southern States Energy Board

State Officials
- California, Illinois, Indiana, Michigan, Mississippi, Montana, New Mexico, Texas and West Virginia

National Enhanced Oil Recovery Initiative

Overview of the Initiative

Sponsors

- **Charitable Foundations**: Joyce Foundation, Edgerton Foundation, Energy Foundation
- **Private Industry**: Arch Coal, Chaparral Energy, Chevron, Continental Resources, Core Energy, Encana, Southern Company, Summit Power, Tenaska

National Enhanced Oil Recovery Initiative

Overview of the Initiative

Bipartisan Congressional Support

Initiative launched in July with participation and endorsements from:

- Sen. John Barrasso (R-WY)
- Rep. Mike Conaway (R-TX)
- Sen. Kent Conrad (D-ND)
- Sen. John Hoeven (R-ND)
- Sen. Richard Lugar (R-IN)

National Enhanced Oil Recovery Initiative

Overview of the Initiative

Three-Part Agenda

- Prepare key analyses to inform and support incentive policies for anthropogenic CO2-EOR
- Recommend and advocate for incentives and other policies to support commercial CO2-EOR deployment that are fully or largely self-financing through revenues from additional incremental oil production.
- Increase policy-maker, media and public awareness of the CO2-EOR, its benefits and need for deployment incentives.

Global

National Enhanced Oil Recovery Initiative

Objectives for Policy

The EOR Initiative will develop, recommend and encourage the implementation of federal and state incentives that:

- Accelerate commercial deployment of CO_2-EOR using anthropogenic CO_2 captured from fossil, renewable and industrial sources;
- Encompass a broad range of CO_2 source industries, projects and capture technologies;
- Bridge the gap between what oil companies can pay for CO_2 and the cost of capturing CO_2 and transporting it to oil fields.
- Ensure net fiscal benefit and sustainability of incentives over time by increasing production of oil without new or additional taxes; and
- Produce more American oil to displace imports, while reducing net CO_2 emissions through oilfield storage of captured anthropogenic CO_2.

Global

National Enhanced Oil Recovery Initiative

Principles for Policy

The EOR Initiative's federal and state incentive recommendations shall:

- **Reduce the net cost of anthropogenic CO_2 delivered** by directing incentive value toward commercial-scale capture projects and development of pipeline networks that makes CO_2 attractive for purchase and use in oilfields;
- **Provide for revenue-neutrality** for federal and state governments over the lifespan of the projects;
- **Ensure financial continuity and certainty** over a defined and limited time period to support commercial capture and pipeline project development, secure private sector investment and reduce capital and O&M costs.
- **Address three priorities simultaneously**: low-cost targets of early opportunity to increase anthropogenic CO_2 supply, competitive commercial-scale development and deployment of critical long-term capture technologies, and build-out of new pipeline capacity.

Global

National Enhanced Oil Recovery Initiative

Analytical Inputs

- **"Cost gap" analysis**: (difference between willingness to pay by EOR operators and cost of carbon capture, storage and transportation)
  - GOAL: Determine the level of incentive needed for incremental new CO_2-EOR.
  - Methodology and spreadsheet tool complete; working to improve data.
- **"Revenue neutrality" analysis**:
  - GOAL: Determine the fiscal impact of new CO_2-EOR incentives.
  - Compare the cost of new CO_2-EOR incentives with new federal revenues from increases in oil royalties, corporate income tax, and person income tax directly and indirectly resulting from incremental new CO_2-EOR production.
  - Analysis now underway in preparation for engaging members of Congress and staff regarding budget scoring.

Global

National Enhanced Oil Recovery Initiative

Analytical Inputs

Economic/jobs impacts of CO_2-EOR incentives

- High-level estimates for incentive impacts based on existing literature for economic and job benefits of domestic oil production.
- Literature review underway.

CO_2 storage benefits

- Commissioned paper outlining:
  - History and experience with CO2 management and storage in context of BAU commercial EOR;
  - What can be claimed for storage to date based on that operational experience; and
  - Recommendations going forward for demonstrating and verifying CO2 storage as part of commercial EOR.

Global

National Enhanced Oil Recovery Initiative

Policy Recommendations Forthcoming

- **Design of a major revenue-neutral federal domestic energy security incentive for EOR using CO2 from fossil, renewable and industrial sources**
  - Participants working on key design attributes of a federal incentive that will incorporate pending analyses regarding cost gaps and revenue neutrality

Global

1:00–2:30 PM Session

National Enhanced Oil Recovery Initiative

Policy Recommendations Forthcoming

- **Proposed revisions to existing 45 Q CO2 capture and storage tax credit**
  - Participants developing consensus comments on how to reform 45Q
  - Working through overlapping members to try and harmonize recommendations with other associations and organizations submitting comments

National Enhanced Oil Recovery Initiative

Policy Recommendations Forthcoming

- **Input on current legislation**
  - Participants developing consensus comments regarding proposed revisions to:
    - EOR component of Senator Lugar's Practical Energy Plan
    - Relevant provisions in Senator Conrad's recent FUEL Act

National Enhanced Oil Recovery Initiative

Policy Recommendations Forthcoming

- **Recommendations regarding CO2-EOR on public lands with existing oil and gas development**
  - Recommendations for how BLM, the Bureau of Mines and other federal agencies can encourage CO2-EOR on federal lands already impacted by oil and gas development.
  - Wyoming participants preparing draft recommendations based on experience with BLM in Big Horn Basin and analysis highlighting economic, energy security and environmental benefits of expanded CO2-EOR on public lands.

Global

National Enhanced Oil Recovery Initiative

Messaging and Outreach

Materials for policy-makers, media and public:

- Address lack of awareness of commercial CO2-EOR and its economic, energy security and environmental benefits:
  - Newspaper op-ed making case for CO2-EOR to be submitted around the country;
  - Two pagers on: overview of CO2-EOR, economic benefits, environmental benefits and safety; and
  - Forthcoming: two-pagers on importance and benefits of CO2-EOR to the coal industry, natural gas industry, agriculture, and potentially other sectors.

Global

National Enhanced Oil Recovery Initiative

Conclusion: Many Benefits from Further CO2-EOR Deployment

COMMERCIAL CO_2-EOR SUPPORTS URGENT NATIONAL PRIORITIES:

- **Increase U.S. oil production** from existing mature oil fields at lower risk and impact than drilling in new areas;
- **Strengthen America's national security** by reducing dangerous dependence on unstable and/or hostile regimes supplying the world oil market;
- **Reduce trade deficits** by keeping petroleum expenditures at home and at work in the American economy;
- **Create new, high-paying American jobs** and retain and attract private sector investment in the U.S. economy;
- **Enable commercial deployment of CCS industry** to the long-term benefit of coal, natural gas, ethanol and other domestic industrial sectors;
- **Facilitate compliance and participation in low-carbon fuels markets** by oil, natural gas and ethanol producers; and
- **Achieve significant net carbon reductions** through CCS.

➢ **Potential for viable agenda and coalition in challenging economic and political times!**

National Enhanced Oil Recovery Initiative

THANK YOU!

BRAD CRABTREE, POLICY DIRECTOR
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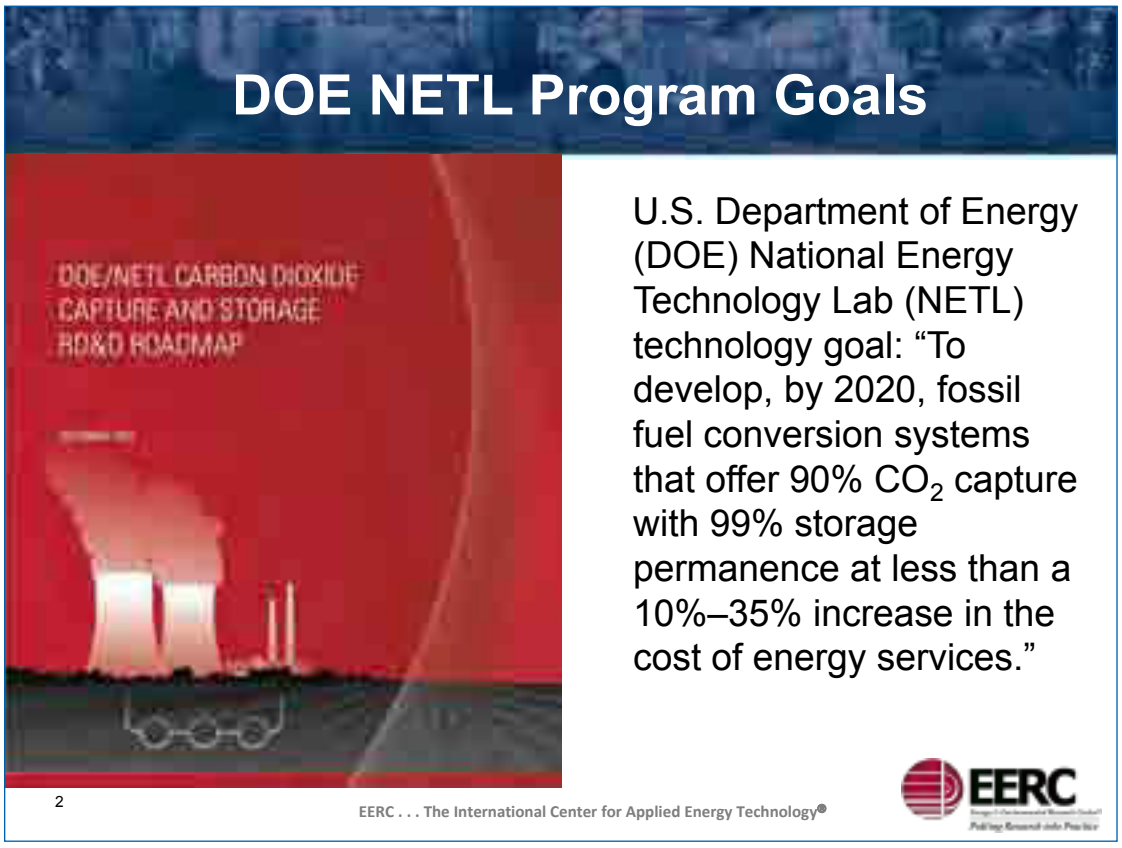
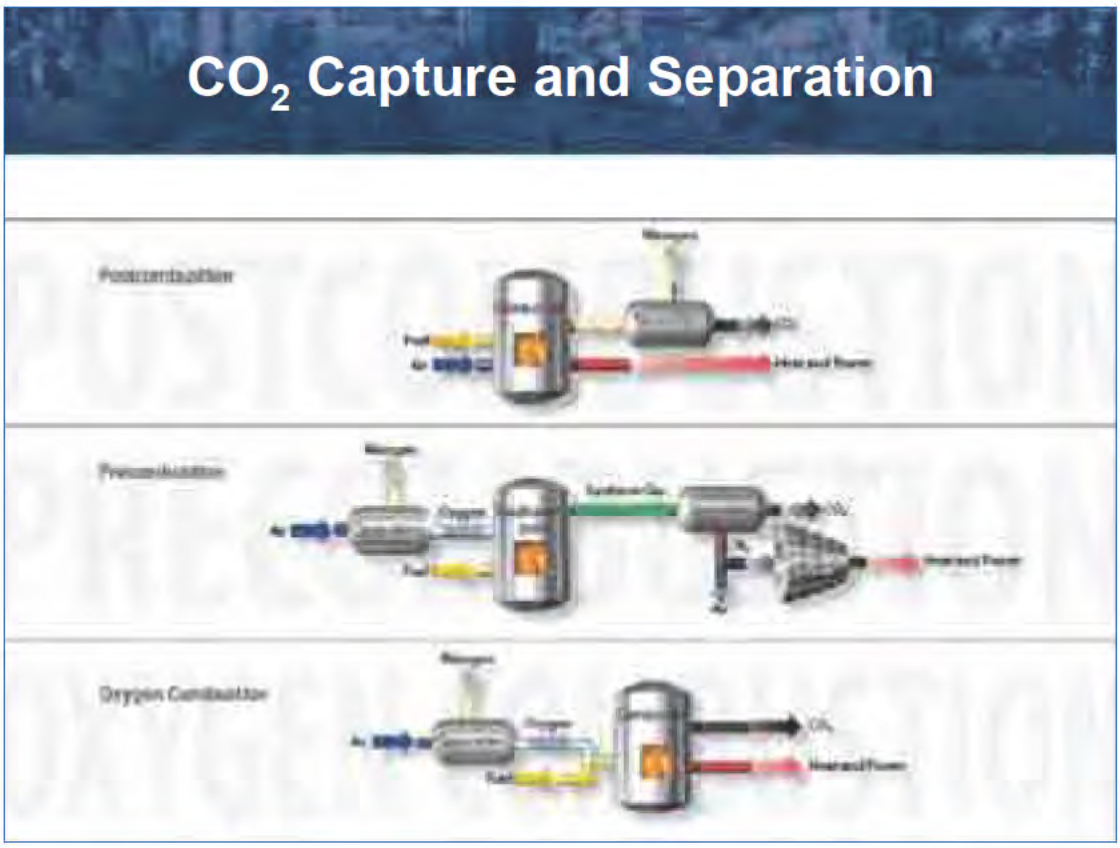
BCRABTREE@GPISD.NET

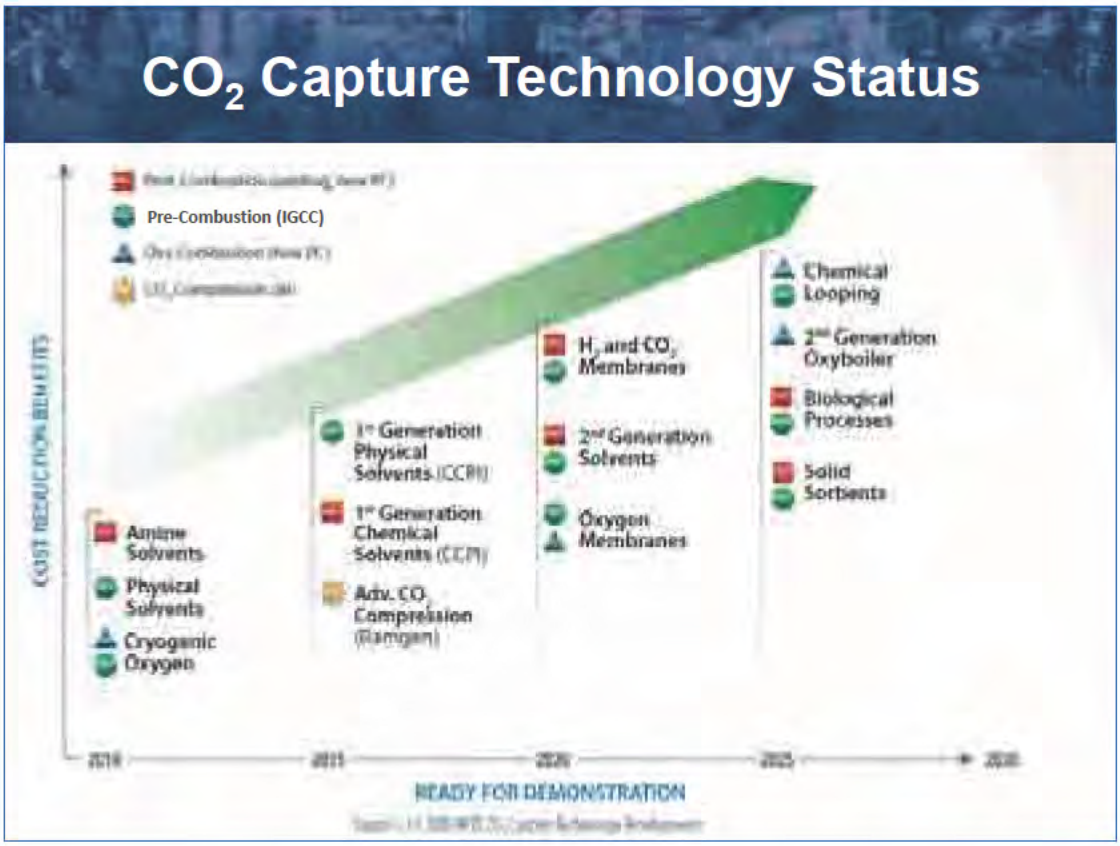
Deputy Associate Director for Research, Energy & Environmental Research Center, University of North Dakota

MICHAEL HOLMES is a Deputy Associate Director for Research at the Energy & Environmental Research Center, where he currently oversees fossil energy research areas. Mr. Holmes' principal areas of interest and expertise include emission control; fuel processing; production of syngas for coproduction of hydrogen, power, fuels, and chemicals; and process development and economics for advanced energy systems. Mr. Holmes has extensive experience in development of emission control technologies, including particulate control, SO_2, NOx, trace metals, and CO_2. In addition, he is the Program Manager of the National Center for Hydrogen Technology® at the EERC and is working under agreement with the US Department of Energy National Energy Technology Laboratory and over 85 partners to develop a broad range of technologies required to advance the opportunities for hydrogen.

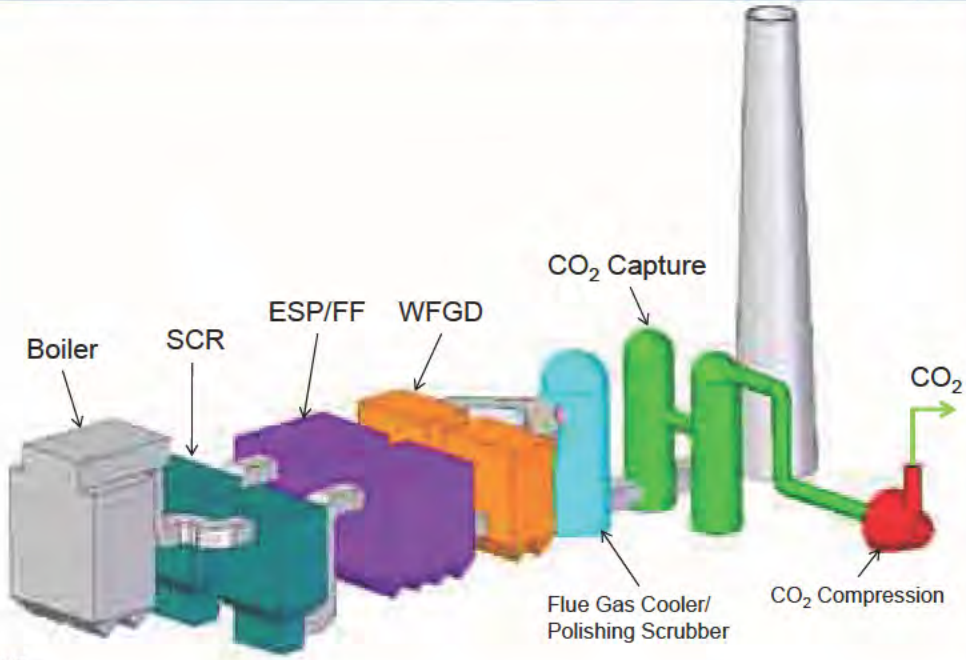


1:00–2:30 PM Session


CO_2 Capture and Separation
Oxygen Combustion


CO_2 Capture Technology Status
Pre-Combustion (IGCC)
Chemical Looping
2nd Generation Oxyboiler
Biological Processes
Solid Sorbents
H_2 and CO_2 Membranes
2nd Generation Solvents
Oxygen Membranes
1st Generation Physical Solvents (CCPI)
1st Generation Chemical Solvents (CCPI)
Adv. CO_2 Compression (Ramgen)
Amine Solvents
Physical Solvents
Cryogenic Oxygen
COST REDUCTION BENEFITS
READY FOR DEMONSTRATION

Postcombustion Capture



*Not to scale

Development Focus Areas for CO_2 Capture Implementation in Coal-Fired Power Plants

- Scale-up
- Energy penalty
  - 20% to 30% less power output
- Cost
  - Current costs are $40 to $80 per ton of CO_2 (80% ICOE).
  - Very capital intensive ($1500 to $2000/kW).
- Contaminants
- Resource availability and sector readiness
  - Supply of solvents or sorbents will be limited.
  - Manufacture of air separation units (ASUs) and other large equipment will be a handcuff to implementation.
- Regulatory framework
  - Lots of unknowns and liability issues.

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1:00–2:30 PM Session

Solvents and Advanced Solvents: Amines

State-of-the-Art Postcombustion Capture

- Fluor Daniel Econamine FG^{SM}
  - 30% MEA solution incorporating additives to control corrosion and (oxidative and thermal) degradation
  - >20 commercial plants ranging in size from 5 to 400 tons CO_2/day
- ABB-Lummus
  - 15%–20% MEA solution
  - Four commercial plants ranging in size from 150 to 850 tons CO_2/day
- Mitsubishi Heavy Industries
  - KS-1 – sterically hindered amines
  - Two commercial plants: ~210 and 330 ton CO_2/day
- Cansolv
  - Mixture of amines
  - Commercial plant case study at NSC (Japan)
- HTC Purenergy
  - Mixture of amines with focus on a modular 1000-ton/day system

7 EERC . . . The International C

Solvents and Advanced Solvents: Amines

State-of-the-Art Postcombustion Capture

- DOW/Alstom Power
  - Advanced Amine Process, pilot plant in operation.
- Hitachi H3-1
  - Proprietary mixture of amines, in process with a 5-MW demonstration.
- Huntsman Chemical
  - Proprietary mixture of amines with bench- and small-pilot-scale data.
- Powerspan
  - ECO_2 Ammonia Process – 1-MW slipstream pilot plant – Changed solvents and are no longer using an ammonia-based system.

Ammonia Processes

- Alstom
  - Chilled ammonia – AEP Demonstration, We Energies pilot plant, and other slipstream demonstrations.

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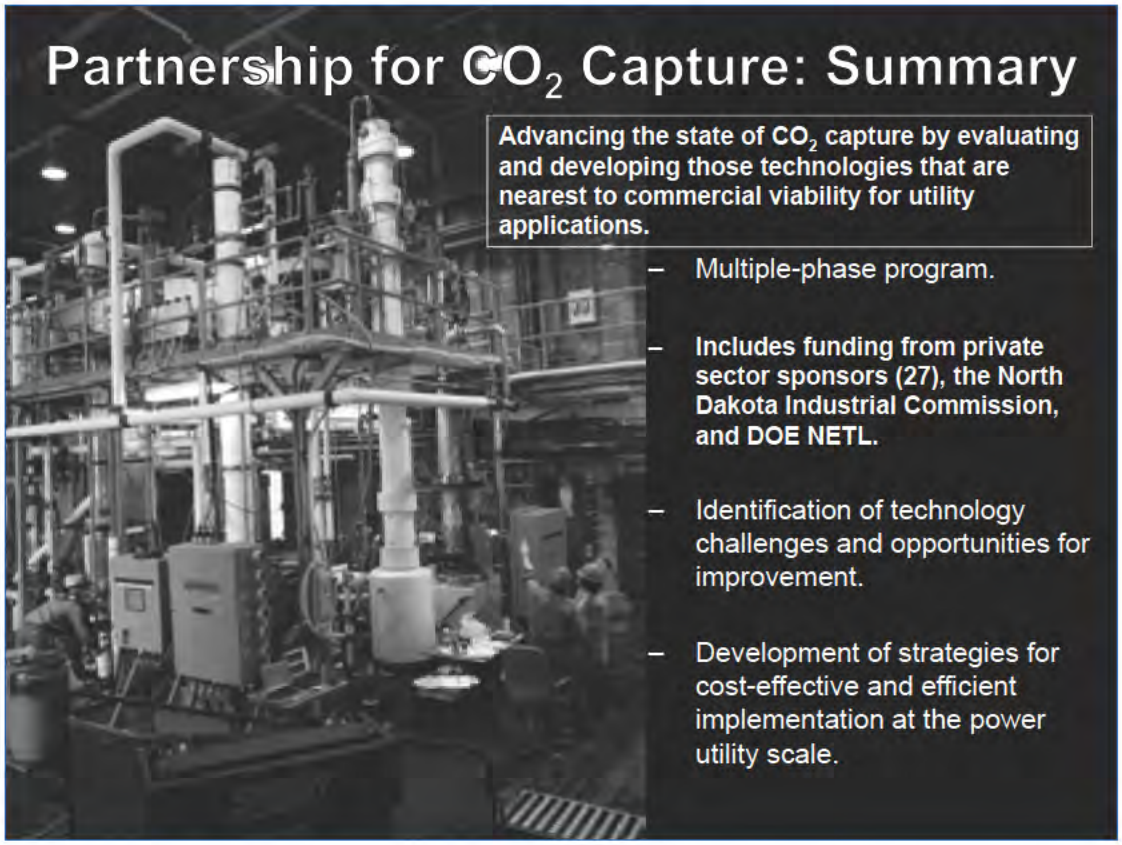

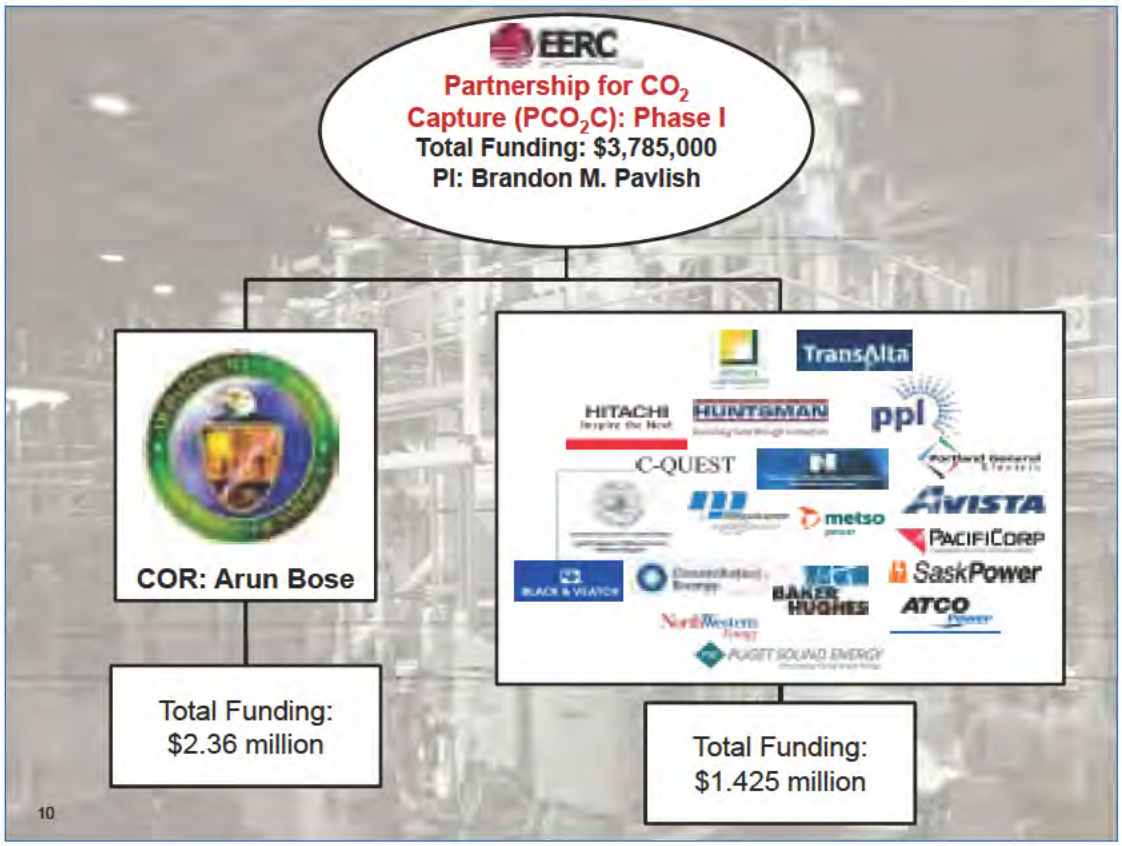

1:00–2:30 PM Session

PCO_2C Project Overview

- Scope of work included eight main tasks:
  - ***Task 1 – Postcombustion Test System(s) Design, Construction, and Implementation***
  - ***Task 2 – Oxygen-Fired Retrofit***
  - ***Task 3 – Conduct CO_2 Capture Technology Testing***
  - ***Task 4 – Systems Engineering and Design***
  - ***Task 4.5 – Water and Energy Sustainability Technology (WEST)***
  - ***Task 5 – Management and Reporting***
  - Task 6 – Further Evaluation of Promising Technologies
  - Task 7 – Strategic Studies
  - Task 8 – Commercial Partner-Specific Testing – Emerging Technologies

Phase I **Phase II** **Phases I and II**

11

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Combustion Test Facility (CTF)

- 550,000 Btu
- Up-fired
- Air- or O_2-fired
- Multifuel capability
  - Coal, biomass, gas, liquid fuel, sludge, and municipal solid waste

- Features
  - Air preheater and heat exchangers
  - Adjustable swirl burner
  - Deposition section
  - Numerous ports
  - Selective catalytic reduction (SCR) reactor
  - Baghouse
  - Electrostatic precipitator (ESP)
  - Sulfur scrubber
- Testing of fuels and additives
  - Fouling and slagging
  - Corrosion
  - Hg
  - NO_x
  - SO_x
  - CO_2 capture
  - Particulates
  - Heat flux
  - Infrared (IR) flame characterization

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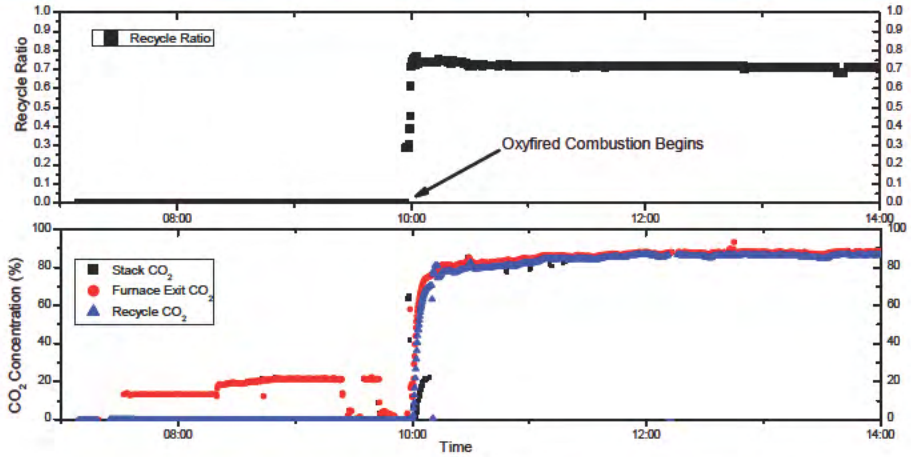
Oxy-Fired Retrofit Results



Flue Gas CO_2 Concentration from Run 1046
Using Paintearth Subbituminous

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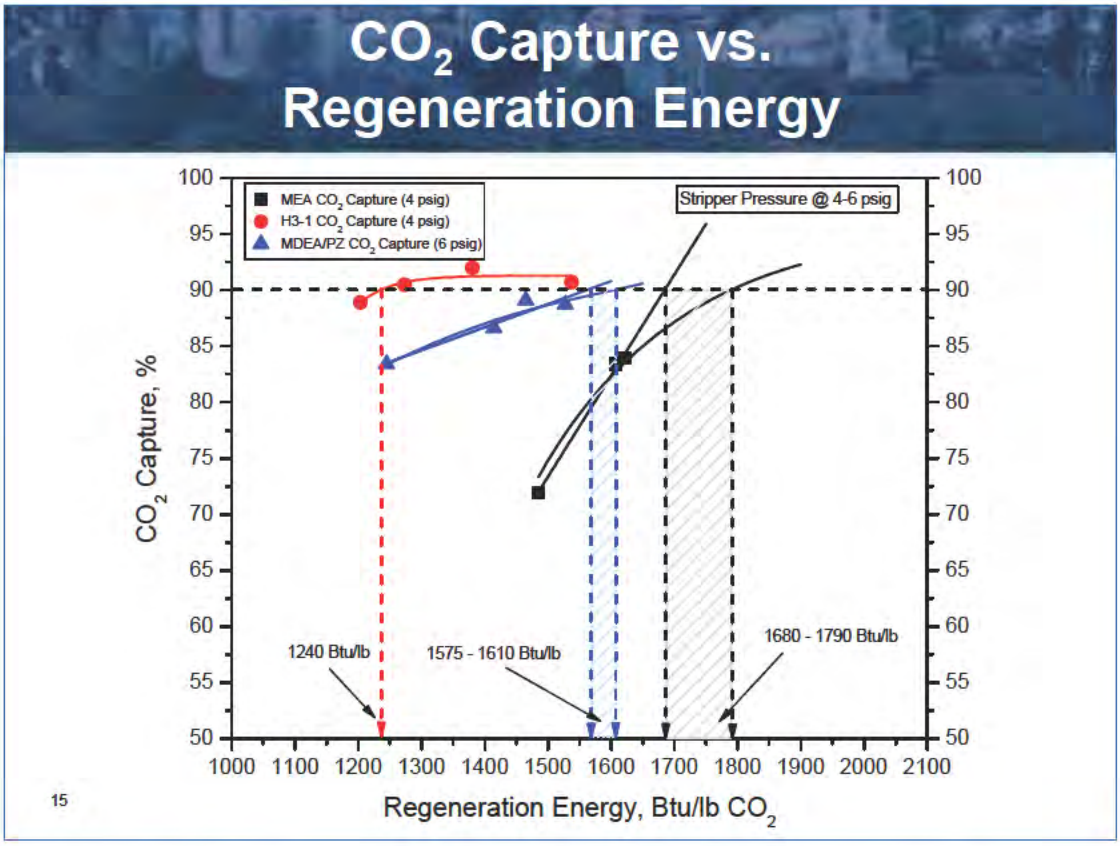
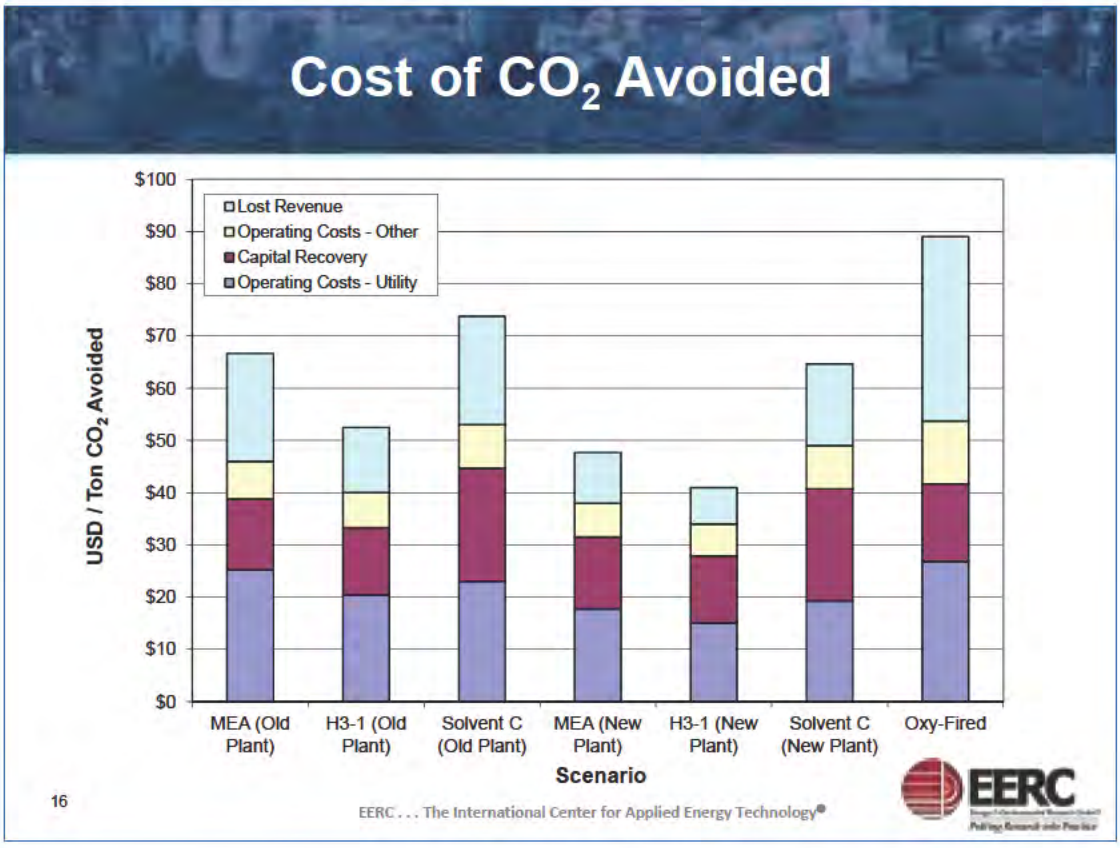
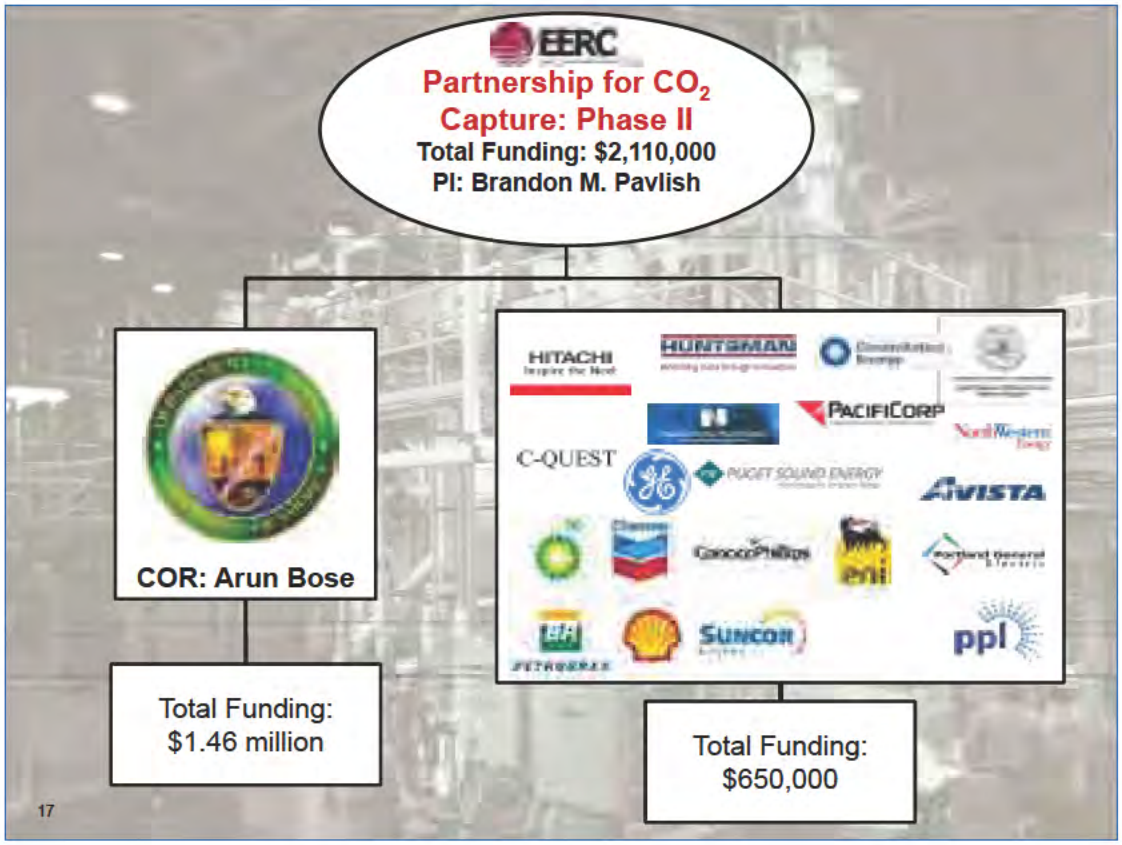
1:00–2:30 PM Session

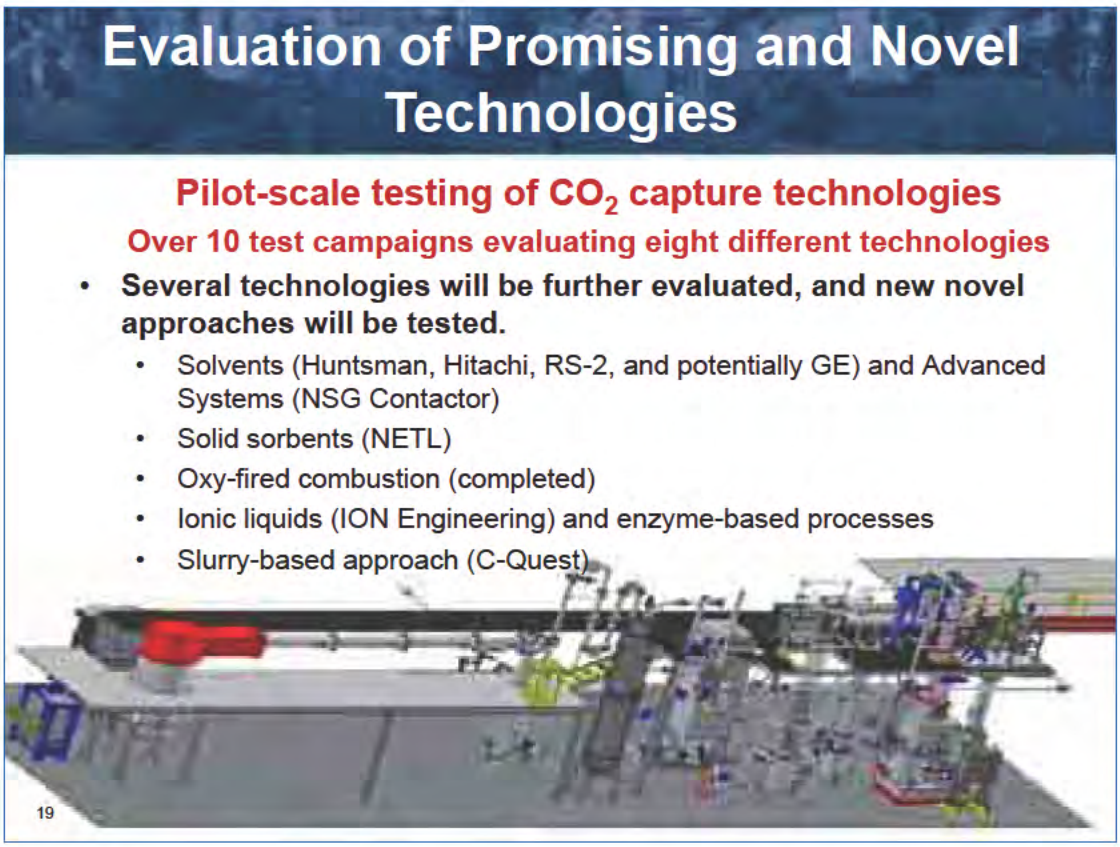

CO2 Capture vs. Regeneration Energy
MEA CO2 Capture (4 psig)
H3-1 CO2 Capture (4 psig)
MDEA/PZ CO2 Capture (6 psig)
Stripper Pressure @ 4-6 psig
1240 Btu/lb
1575 - 1610 Btu/lb
1680 - 1790 Btu/lb
CO2 Capture, %
Regeneration Energy, Btu/lb CO2
15

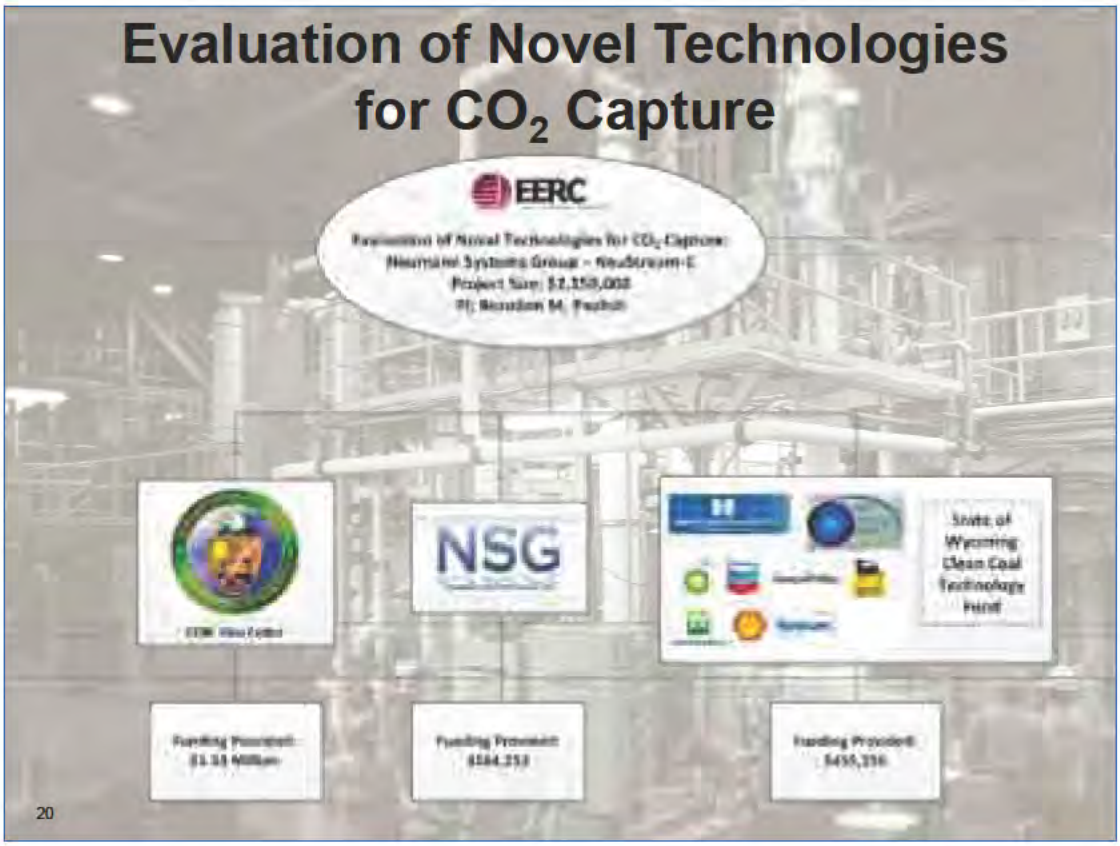

Cost of CO2 Avoided
Lost Revenue
Operating Costs - Other
Capital Recovery
Operating Costs - Utility
USD / Ton CO2 Avoided
MEA (Old Plant)
H3-1 (Old Plant)
Solvent C (Old Plant)
MEA (New Plant)
H3-1 (New Plant)
Solvent C (New Plant)
Oxy-Fired
Scenario
16
EERC . . . The International Center for Applied Energy Technology®
EERC



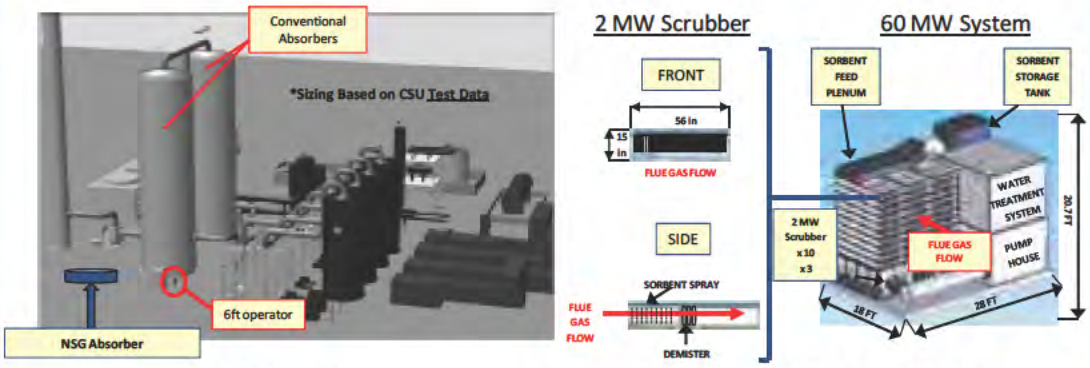
PCO_2C: Phase II

- The overall goal of Phase II is to further evaluate the most promising technologies from Phase I that may be ready for large-scale demonstration.
- Demonstrate/develop novel technologies (solid sorbents, enzymatic processes, ionic liquids).
- Determine ways (integration options) to reduce cost and power consumption.


Evaluation of Promising and Novel Technologies
Pilot-scale testing of CO_2 capture technologies
Over 10 test campaigns evaluating eight different technologies
• Several technologies will be further evaluated, and new novel approaches will be tested.
• Solvents (Huntsman, Hitachi, RS-2, and potentially GE) and Advanced Systems (NSG Contactor)
• Solid sorbents (NETL)
• Oxy-fired combustion (completed)
• Ionic liquids (ION Engineering) and enzyme-based processes
• Slurry-based approach (C-Quest)
19


Evaluation of Novel Technologies for CO_2 Capture
EERC
NSG
State of Wyoming Clean Coal Technology Fund
20

Multi-Pollutant Capture And Processing Systems



90% Smaller **Modular Design**

50% Lower CapEx
40% Lower OpEx

Through NSG Mechanical Advancement

Useful With Variety of Chemistries

21

1

DOE Regional Carbon Sequestration Partnership Program

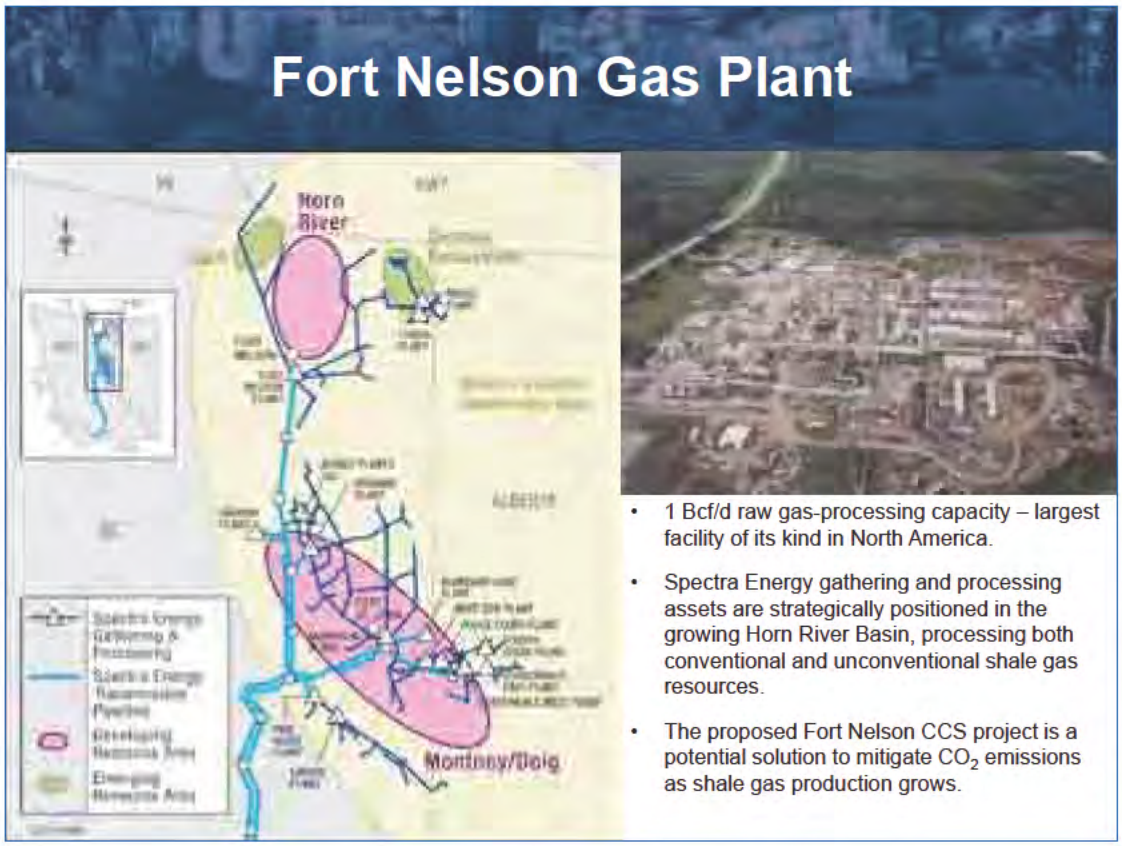
- Seven partnerships, all tasked with regional characterization and site-screening activities.
- Screening along with economic drivers have resulted in several large-scale demonstration projects.

EER

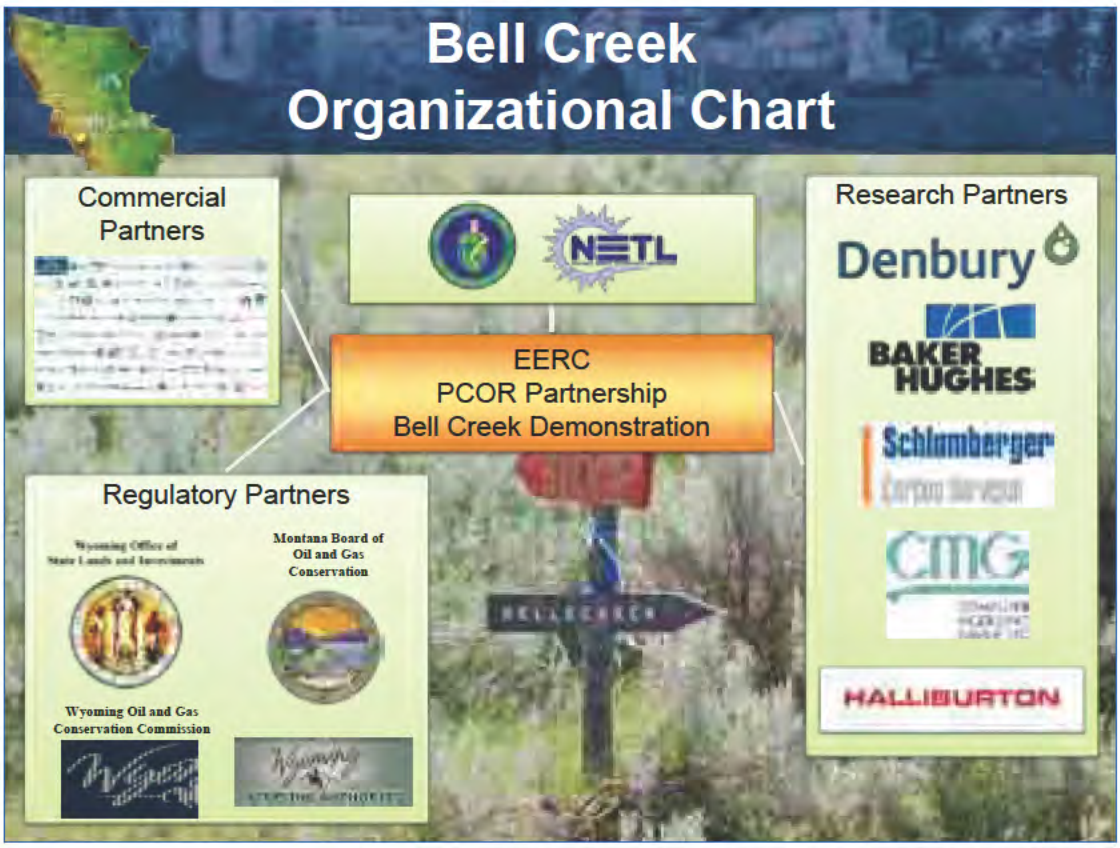
1:00–2:30 PM Session

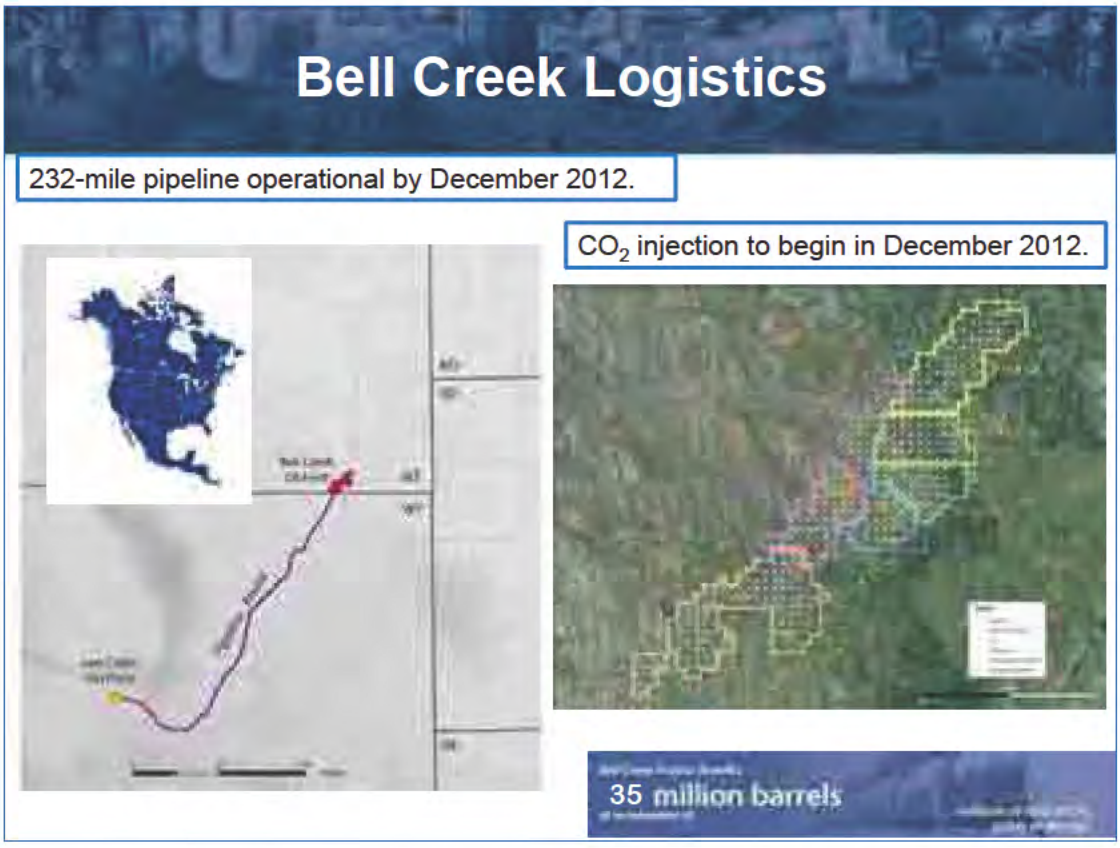
Commercial-Scale Demonstration Phase

- Two 1-million-ton/year-or-greater-scale demonstrations
  - Saline
  - Enhanced oil recovery (EOR)
- Ongoing and effective public outreach
- Continuing regional characterization
- Continued involvement in other carbon dioxide (CO_2) storage projects in the region.
- Continued involvement in carbon capture and storage (CCS) and CO_2/EOR regulations



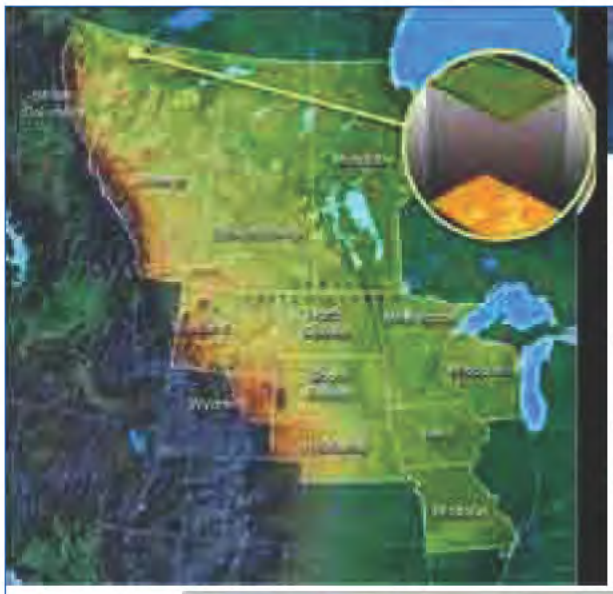
1:00–2:30 PM Session


Bell Creek
Organizational Chart
Commercial Partners
NETL
EERC
PCOR Partnership
Bell Creek Demonstration
Research Partners
Denbury
BAKER HUGHES
Schlumberger
CMG
HALLIBURTON
Regulatory Partners
Montana Board of Oil and Gas Conservation
Wyoming Oil and Gas Conservation Commission


Bell Creek Logistics
232-mile pipeline operational by December 2012.
CO_2 injection to begin in December 2012.
35 million barrels

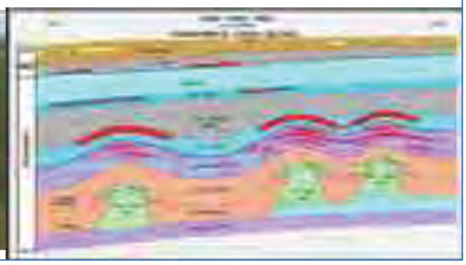
Additional Projects

- ✓ Regional Characterization
- ✓ Basal Cambrian
- ✓ Aquistore
- ✓ Zama
- ✓ Water Working Group (WWG)
- ✓ Outreach
- ✓ Regulatory Involvement



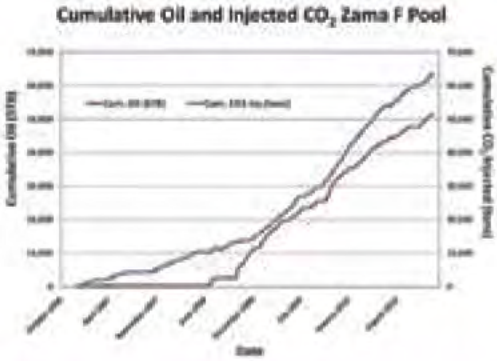
Zama EOR and CCS Project

- Operated by Apache Canada Ltd.
- Injection of acid gas is ongoing and will continue as an EOR scheme.
- Implement a cost-effective approach for MVA.
- Pinnacle reef structure.
- Similar lithology found in the Williston and Powder River Basins.



1:00–2:30 PM Session

Zama Operations and MVA



- Injection began December 15, 2006
- Over 60,000 tons CO_2 injected
- Over 50,000 incremental bbl oil produced

The Zama MVA program was developed using the current Alberta regulatory framework for acid gas injection. Characterization activities were added to fully describe the system and provide confidence in the safe and secure storage of injected fluids.

Conclusion

The PCOR Partnership region has huge CCS potential!

Contact Information

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Mike Holmes
Deputy Associate Director for Research
mholmes@undeerc.org

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1:00–2:30 PM Session

Scientist, Climate Center, Natural Resources Defense Council

GEORGE PERIDAS is a Scientist at NRDC's Climate Center, where currently he leads NRDC's efforts in Carbon Capture & Sequestration technology, regulation, and policy, and also plays an active role in the organization's state and federal climate and energy advocacy efforts. Prior to joining NRDC in October 2006, George worked as a Senior Consultant on energy markets for Pöyry. His areas of expertise include power, oil, natural gas, and renewables markets, as well as emissions trading. George received his M.Eng. and Ph.D. degrees in mechanical engineering from the University of Oxford and his M.Sc. in Environmental Science & Policy from Imperial College, London. He comes from Athens, Greece.

CCS in California

George Peridas,
Natural Resources Defense Council

4th November, 2011
Washington, DC

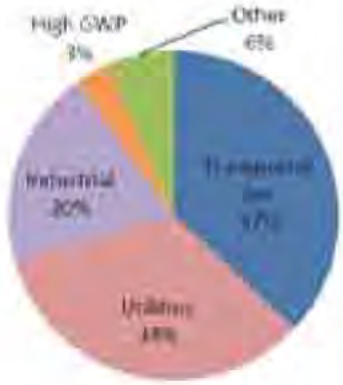
Outline

- Emissions and climate policies in CA
- Achieving the climate goals
- The potential role for CCS
- Policies and regulations
- Projects
- WestCarb NGCC/CCS study

Emissions and goals

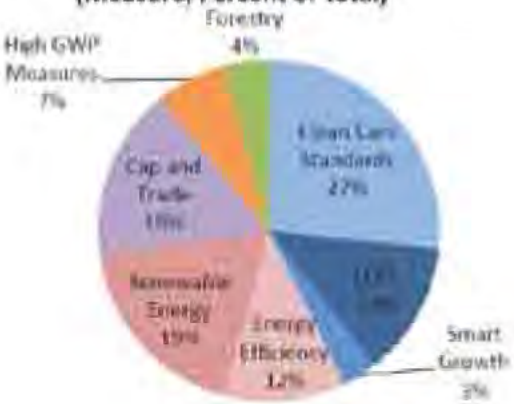
- AB 32: reduce to 1990 levels by 2020, and 80% below 1990 levels by 2050

California Emission Sources (2008)
(Sector, Percent of Total)



Source: CARB, California GHG Inventory for 2000-2008

AB 32 Emission Reduction Strategies
(Measure, Percent of Total)



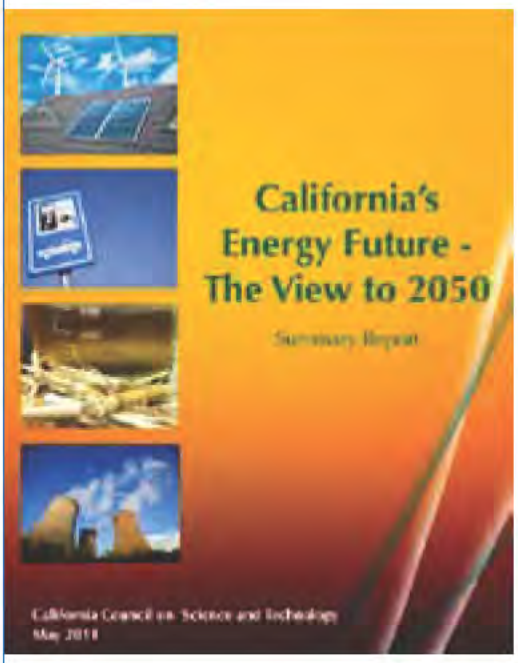
Source: CARB, Emissions Reductions from Scoping Plan Measures; 2020 GHG Emissions Forecast

AB32 milestones

Jan/May 2007	CPUC and CEC adopt SB 1368 regulations, establishing an emissions performance standard for new long-term commitments in baseload power
April 2008	CEC updates Title 24 building energy efficiency code
October 2008	CARB adopts mandatory GHG reporting regulations
November 2008	CPUC directs investor-owned utilities (IOUs) to help more than one million low income households become more energy efficient from 2009-2011
December 2008	CARB adopts Scoping Plan
April 2009	CARB approves Low Carbon Fuel Standard (LCFS)
September 2009	CPUC appr[illegible]10-2012 IOU [illegible]ergy efficiency progra[illegible] exp[illegible]ed to achieve savings equivalent to avoiding [illegible]ee [illegible] pla[illegible]
September 2009	CARB final[illegible] stand[illegible]
November 2009	CEC adopts landmark TV energy efficiency standards
March 2010	California's public utilities commit to energy efficiency programs that will achieve savings equivalent to avoiding two large power plants by 2020
September 2010	CARB sets regional GHG targets under SB 375
December 2010	CARB approves cap and trade regulation
March 2011	Legislature passes 33% Renewable Portfolio Standard
July 2011	In conjunction with CARB, federal agencies and major automakers, President Obama announces agreement to increase fuel economy standards for passenger vehicles to 54.5 MPG by 2025
October 2011	CARB adopts final cap and trade regulation
January 2012	Cap and trade program goes into effect
December 2013	CARB updates the Scoping Plan

On track!

How to get there?



- "California can achieve emissions roughly 60% below 1990 levels with technology we largely know about today if such technology is rapidly deployed at rates that are aggressive but feasible"
- "We could further reduce 2050 greenhouse gas emissions to 80% below 1990 levels with significant innovation and advancements in multiple technologies that eliminate emissions from fuels. All of these solutions would require intensive and sustained investment in new technologies plus innovation to bridge from the laboratory to reliable operating systems in relatively short timeframes"

CCST report in more detail

- Getting to 60%:
  - Four key actions:
    - Efficiency measures
    - Electrification
    - Decarbonizing electricity supply and zero-emissions load balancing
    - Decarbonizing the remaining required fuel supply where electrification is not feasible.
  - "If electric generation is predominantly intermittent renewable power, using natural gas to firm the power would likely result in greenhouse gas emissions that would alone exceed the 2050 target for the entire economy"
  - "CCS would modify an existing electricity pathway to provide a transition to the future, but relies on the large-scale development of a system of underground CO_2 storage"

1:00–2:30 PM Session

CCST report in more detail

- Achieving 60%:

Strategy	Assumed Plant Size	Total Plant Capacity Needed by 2050	Build Rate 2014-2050 (Plants/Year)
Nuclear	1.3 GW	44 GW	0.73
Bio/CCS	1.3 GW	34 GW*	0.80
Renewables Mix total		163 GW**	
- Wind	500 MW	59 GW	3.0
- Central Solar (CSP and PV)	400 MW	95 GW	1.3
- Distributed Solar PV	3 kW	25 GW	110,000
Biomass/CCS	300 MW	1.3 GW	0.77
CA Biofuels	30 Bgge/yr	3.3 Bgge/yr	2.8
Hydrogen		8.0 Bgge/yr	
- Natural Gas Reforming	0.7 Bgge/yr	0.8 Bgge/yr	40
- Central Plant	440 Bgge/yr	7.2 Bgge/yr	0.41

Table 2. Summary of supply build rates required.
*Gross capacity, assuming 10% parasitic loss from CCS (net capacity = 19 GW)
**Includes geothermal and hydropower not included in this table

CCST report in more detail

- Achieving 80%:
  - "CCS is likely to be an important part of several possible schemes to provide hydrogen, low-carbon fuels or offsets that allow continued fossil fuel use. For California, the utility of CCS in achieving a low carbon fuel portfolio could be as important as the utility of CCS for electricity production per se"

CCS Review Panel

- Appointed by CPUC, CEC and CARB to:
  - Identify, discuss, and frame specific policies addressing the role of CCS technology in meeting the State's energy needs and greenhouse gas emissions reduction strategies for 2020 and 2050
  - Support development of a legal/regulatory framework for permitting proposed CCS projects consistent with the State's energy and environmental policy objectives

CCS Review Panel (cont.)

- Among the key recommendations (Dec. 2010):
  - Recognize CCS (appropriately regulated) as a mitigation measure and devise protocol
  - Apportion regulatory roles to specific agencies
  - Consider a trust fund for post-injection stewardship
  - Evaluate incentives for early projects and consider implementing those that are most cost-effective
  - Others: pipeline siting, pore space ownership, outreach, sharing of burdens and benefits

Projects

- HECA I:
  - Carson: bad choice of location
- HECA II:
  - Too expensive
- HECA III:
  - New siting challenges?
- Martinez refinery:
  - Plans shelved in favor of tar sands project
- Other projects?

Gas in CA

- Accounts for ~50% of generation
- NGCC plants among the largest point sources
- High capacity factors, high remaining life

Credit: WestCarb; Rich Myhre, BKi

WestCarb NGCC/CCS study

- Partners: CEC, PG&E, Stone&Webster, LLNL, LBNL, BKI, NETL
- Screen candidate CCS technologies for new and existing NGCC plants
- Examine: permitting, HSE, water use
- Screen CO_2 storage options and build static geomodels
- Build engineering-economic models and evaluate selected CCS technology and NGCC unit combinations
- Develop a conceptual design for a pilot-scale CCS test on a California NGCC unit or cogeneration unit

Credit: Rich Myhre, BKi

References

- CARB Emissions Trading Program (factsheet): http://www.arb.ca.gov/newsrel/2011/cap_trade_overview.pdf
- California's Energy Future – The View to 2050 (CCST): http://www.ccst.us/publications/2011/2011energy.php
- CA CCS Review Panel: http://www.climatechange.ca.gov/carbon_capture_review_panel/index.html
- Engineering-Economic and Geologic Assessment of CCS Application to California NGCC Power Plants: http://www.westcarb.org/pdfs/2011_CCS_NGCC_study_Myhre.pdf

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2:45–4:15 PM Session

Deploying CCS on Natural Gas: Policy and Regulatory Landscape

Vice President,
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Policies to Advance the Business Case for Natural Gas Combined Cycle Power Plants with Carbon Capture and Storage

Prepared by

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Prepared for

American Clean Skies Foundation

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NOVEMBER 2011

2:45–4:15 PM Session

Policies to Advance the Business Case for NGCC with CCS

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Introduction

Carbon capture and storage (CCS) deployed on natural gas combined cycle (NGCC) plants is an important technological option to reduce greenhouse gas (GHG) emissions in the United States. The timeframe for deployment of the technology depends on the aggressiveness with which the U.S. addresses climate change and the cost effectiveness of NGCC with CCS relative to other GHG reduction strategies for the electric sector. The argument for CCS on natural gas-fired units echoes the argument for CCS on coal-fired units: there is a large domestic resource of natural gas, there are a large (and growing) number of natural gas-fired power plants supplying electricity in the U.S., and natural gas combustion results in greenhouse gas emissions. The challenges to CCS use on natural gas-fired units are similar to the challenges to CCS use on coal-fired units: integrated CCS has not been proven at scale on an electric generating unit and CCS is expensive relative to other forms of electricity – particularly relative to generation of electricity from combustion of fossil fuels in the absence of a price on carbon.

The goal of policies to support NG-CCS (and CCS technology develop in general) should be to accelerate the demonstration and deployment of the technology with the expectation that there will be a mandate to reduce GHG in the future and having the option to deploy CCS on natural gas in the future will reduce overall (societal) costs of compliance.

This focus is reflected in the Administration goal of five to ten commercial demonstration plants as outlined by President Obama in a Presidential Memorandum that created the Interagency Task Force on CCS:

> *The Task Force shall develop within 180 days of the date of this memorandum a proposed plan to overcome the barriers to the widespread,* ***cost-effective deployment of CCS within 10 years, with a goal of bringing 5 to 10 commercial demonstration projects online by 2016.*** *The plan should explore incentives for commercial CCS adoption and address any financial, economic, technological, legal, institutional, social, or other barriers to deployment.* [1]

Perspectives on CCS Deployment

The timeframe for CCS deployment is challenging to predict because its use is predicated on (1) the timing and aggressiveness of GHG reductions, (2) the demonstration of the technology at a commercial scale, and (3) the degree of financial support for early movers. At one end of the spectrum, modeling suggests reduction pathways in the range of 80 percent below 2005 levels by 2050 combined with significant demonstration and early mover incentives and a focus on domestic emission reductions could encourage CCS on natural gas-fired power plants before 2020. At the other end of the spectrum, modeling suggests reduction pathways in the range of 50 percent below 2005 emissions by 2050 might not require deployment of CCS on natural gas-fired power plants to the closing years of this half century.

[1] The White House Office of the Press Secretary, "Presidential Memorandum: A Comprehensive Federal Strategy on Carbon Capture and Storage," February 3, 2010. http://www.whitehouse.gov/the-press-office/presidential-memorandum-a-comprehensive-federal-strategy-carbon-capture-and-storage

Policies to Advance the Business Case for NGCC with CCS

Modeling of the American Power Act of 2010 (APA), a comprehensive climate bill released by Senators Kerry, Graham, and Lieberman but never voted on by the Senate, provides an example of some of the more aggressive scenarios.[2] The bill, based on a bill that passed the House in June 2009, the American Clean Energy and Security Act of 2009 (H.R. 2454, sometimes call the Waxman-Markey Climate Bill), included a cap on GHG emissions and significant incentives for the development and deployment of CCS. The primary incentives took the form of bonus allowances based on tons of carbon dioxide (CO_2) sequestered. The Energy Information Administration's (EIA's) analysis of APA included a number of different economic and technology scenarios. Under the most aggressive domestic reduction scenario, which limited the use of international offsets, the first natural gas-fired power plants with CCS were projected to come online in 2019, three years behind the first coal-fired power plants with CCS. However, the baseline scenarios used natural gas assumptions that did not account for expanded natural gas supply. Under a scenario using high natural gas resource assumptions, reflecting shale gas potential, natural gas-fired power plants with CCS were not projected to start coming online until 2030. The 2030 estimate is consistent with the basic model run which included the EIA reference assumptions and implementation of the bill as designed. Figure 1 shows the coal with CCS deployment estimates (dotted lines) and the NGCC with CCS deployment estimates (solid lines) under four of the scenarios modeled by EIA.

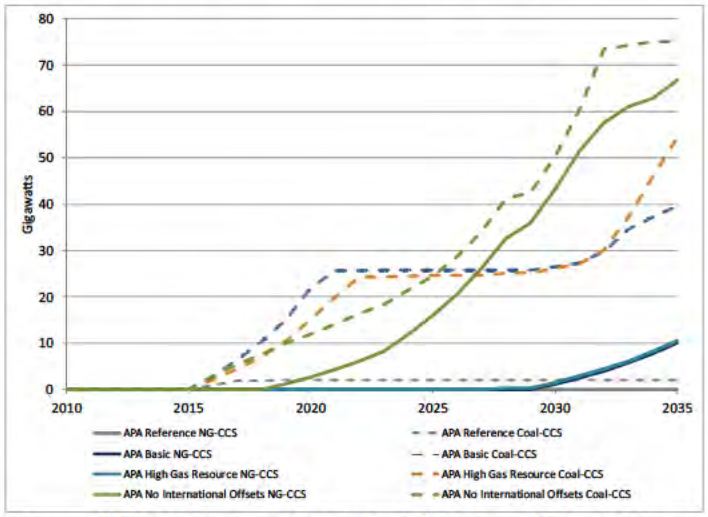

Figure 1. EIA Projections for Coal with CCS and Natural Gas with CCS Under the American Power Act (EIA 2010)

In 2011, MIT Energy Initiative released the latest of a series of reports on the future of energy in the U.S. In its *Future of Natural Gas* report, the researchers developed a "Price-Based Climate Policy" scenario that projected policies that gradually reduced U.S. GHG emissions to 50 percent below 2005 levels by 2050. Under the scenario, natural gas replaces other fossil fuels used for

[2] Energy Information Administration (EIA). *Energy Market and Economic Impacts of the American Power Act of 2010*. Report # SR-OIAF/2020-01. July 16, 2010. http://205.254.135.24/oiaf/servicerpt/kgl/index.html

electricity generation by 2035 and a small amount of CCS is required on natural gas units after 2045.[3] The MIT study authors have noted that all fossil-based electricity would have to be gradually decarbonized using CCS to meet more aggressive post-2050 targets (assuming continued use of fossil fuels). They note that this reality reinforces the need to remove barriers to CCS:

> *Barriers to the expansion of nuclear power or coal and/or gas generation with CCS must be resolved over the next few decades so that over time these energy sources will be able to replace natural gas in power generation. Without such capability, it would not be possible to sustain an emissions mitigation regime.*[4]

In 2010, the California Energy Commission, the California Public Utilities Commission, and the Air Resources Board formed a panel to review CCS policy and develop recommendations for legislation and regulations regarding CCS in California. While it did not establishing a specific deployment scenario, the California CCS Review Panel was particularly interested in CCS combined with natural gas combined cycle plants because of the need to reduce emissions from NGCC plants to meet California's goal of 80 percent reduction below 1990 levels by 2050. The panel cited a number of global studies, including the Intergovernmental Panel on Climate Change (IPCC), International Energy Agency (IEA) and the National Research Council (NRC), that emphasized the need for CCS to meet mid-century GHG reduction targets.[5]

The Electric Power Research Institute (EPRI) has developed a series of technology deployment scenarios for the electric sector over the past five years known as the EPRI Prism. The Prism was designed to provide an engineering judgment of the possible CO_2 emission reductions from the electric sector given current and developing technologies. The newest iteration of the model (Prism 2.0) includes economic modeling and expanded demand-side details by region and technology. EPRI makes coal with CCS and natural gas with CCS available in the model starting after 2020. In a "test drive" of the model with CO_2 prices starting at $30 per ton in 2015 and increasing five percent per year through 2050, natural gas with CCS and coal with CCS squeeze out uncontrolled coal by 2040 and uncontrolled gas by around 2050. An additional insight from the model is that technology selection varies significantly by region. As shown in Figure 2, with a carbon constraint, the EPRI Prism 2.0 projects gas with CCS in the west, east, and south but limited application in the Midwest.[6]

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[3] MIT Energy Initiative. *Future of Natural Gas: An Interdisciplinary MIT Study*. June 2011. http://web.mit.edu/mitei/research/studies/natural-gas-2011.shtml
[4] Ibid. At p 70.
[5] California Carbon Capture and Storage Review Panel. *Findings and Recommendations by the California Carbon Capture and Storage Review Panel*. December 2010. http://www.climatechange.ca.gov/carbon_capture_review_panel/documents/2011-01-14_CSS_Panel_Recommendations.pdf
[6] Hannegan, Bryan. *Prism 2.0: Preliminary Insights from EPRI's Regional Model*. EPRI Summer 2010 Seminar. August 2, 2010.

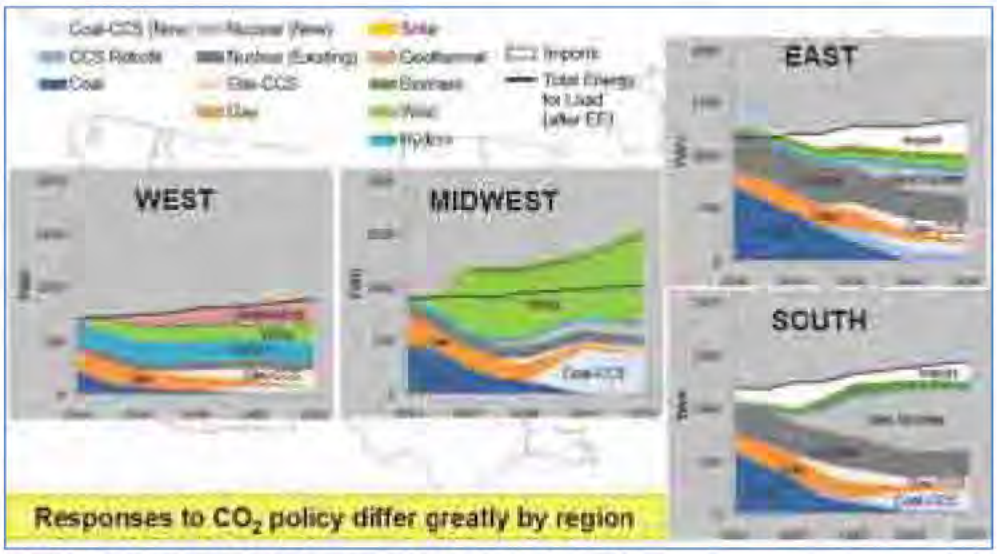

Figure 2. Preliminary EPRI Prism 2.0 Regional Analysis[7]

While each of these studies has different assumptions around technology availability, incentives, and required emission reductions, 2020 is likely the earliest deployment date for commercial-scale NGCC with CCS. Given the current lack of enthusiasm for GHG reduction requirements in the U.S., a case could be made that NGCC with CCS will not be significantly deployed until after 2030.

Barriers to NGCC-CCS Deployment

As with any long-lived asset, power plant construction involves making assumptions about future conditions and becoming comfortable with uncertainties. Before starting construction, planners have to map out expected fuel prices and electricity demand to justify the costs associated with construction. As they evaluate potential costs, investors have to consider the appropriate generation technology, regulatory approval, expected technology performance (efficiency and availability), the location of the power plant (including any local stakeholder concerns), potential construction cost and time overruns, and current (and potential future) environmental regulations. Existing electricity markets – both regulated and deregulated – have developed ways to handle these risks. However, even within mature markets, projects are often announced and cancelled before construction begins.

The addition of CCS to a power plant adds a number of risks that are not fully accounted for in today's electric power markets including uncertainties around: long-term GHG regulations, new technology performance, transportation and storage permitting and liability, and long-term stewardship.

[7] Hannegan, Bryan. *Prism 2.0: Preliminary Insights from EPRI's Regional Model*. EPRI Summer 2010 Seminar. August 2, 2010.

- Uncertainty about the long-term GHG regulatory pathway. Methods of pricing environmental externalities through command-and-control regulation, cap-and-trade systems, or a carbon tax could create a demand for CCS. Lack of certainty encourages waiting and increases the public cost of demonstration.
- New technology risk (first mover). Compounding the lack of a clear mandate to reduce GHGs, a new power plant with CCS is going to have to deal with risks associated with integrating technologies that have limited history of integration – particularly at scale. Shareholders and customers (i.e., public utility commissions) have little incentive to subsidize the development of a technology when the benefits will be diffuse and when there is significant uncertainty about when it will be needed.
- Transport and storage risks. The large volume of CO_2 and the need for pipeline transport off site makes it more challenging than other forms of air pollution that power plants have traditionally addressed. Power companies will have to establish relationships with oil and gas companies that have a comfort level with the transport of CO_2 and the injection and monitoring techniques associated with storage and new service companies will have to be formed. Natural gas-fired plant owners and operators do have significant experience dealing with large volumes of gas in pipelines.
- Long-term stewardship. Long-term risk associated with CO_2 leakage is difficult for companies to assess (particularly on top of the regulatory and technology uncertainties).

GHG Regulatory Uncertainty

The biggest impediment to CCS demonstration and deployment is the lack of a sufficiently stringent program to reduce GHG emissions (i.e., a price on carbon). A requirement to reduce GHG emissions, or a requirement to pay a fee per ton of GHG emissions, would create a market for lower carbon technologies. When the penalty for emitting the carbon is great enough, technologies that produce electricity without the associated carbon emissions will become more economically attractive. Without a requirement to control GHG emissions, fossil fuel-fired generation with CCS will always be more expensive than uncontrolled fossil generation. This makes CCS a non-starter in the absence of GHG control requirements.

Figure 3 summarizes a number of studies of the economics of NGCC with CCS completed between 2007 and 2011. On average, the studies suggest that CCS will add about $30 per megawatt hour (MWh) to the cost of electricity (COE) from a NGCC power plant, with a high estimate of an additional $43 per MWh and a low estimate of an additional $25 per MWh (all in 2007 dollars). The majority of these costs are associated with the capture technology and the energy penalty associated with capturing and compressing the CO_2, transportation and storage costs make up about 10 percent of the costs associated with CCS.

Policies to Advance the Business Case for NGCC with CCS

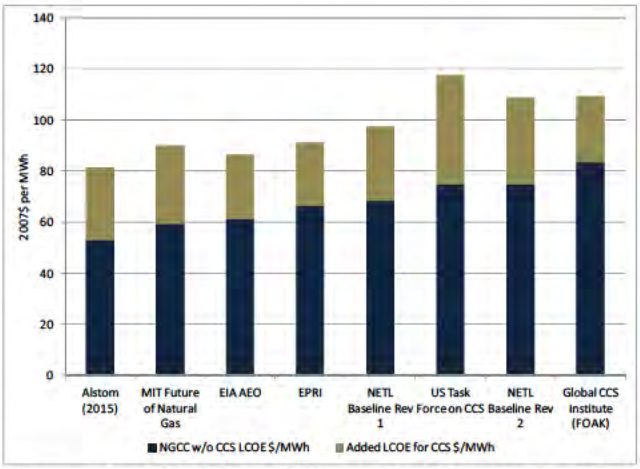

Figure 3. Levelized Cost of Electricity Estimates for NGCC Power Plants with and without CCS (All Estimates Converted to 2007 Dollars)[8]

Looking at the EIA projections for the American Power Act featured in Figure 1, Figure 4 reinforces the need for regulation of GHGs to drive demand for NGCC with CCS. Only with a carbon constraint do electric power prices approach the level needed. The EIA 2011 Annual Energy Outlook projects the cost of generation in the U.S. to average below $60 per MWh (in 2007 dollars) through 2035.[9]

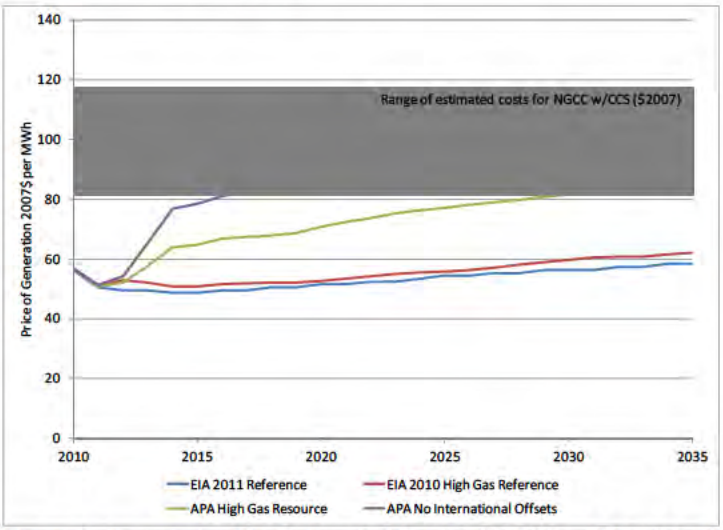

Figure 4. Comparing the Estimated Costs of NGCC with CCS to the Estimated Price of Generation Under Reference and GHG Controlled Cases

[8] See Appendix A for references, additional information.
[9] U.S. Energy Information Agency (EIA), *Annual Energy Outlook 2011*. April 26, 2011. http://www.eia.gov/forecasts/aeo/

Without a clear pathway toward a significant price on GHG emissions in the U.S., either explicitly through a cap-and-trade system or a tax or implicitly through a regulatory requirement, there will not be a long-term market for CCS. In the absence of a clear market, it is challenging to develop a project without significant additional incentives.

In the U.S., there are currently four commercial-scale power plant projects with CCS that are at various stages of planning and development; five projects that have been put indefinitely on hold; and one project, FutureGen 2.0, that recently lost the support of the power plant owner.[10] Table 1 provides some information on the technologies and federal funding amounts associated with these projects. While there are multiple reasons any specific project is put on hold, the circumstances around the projects that were either officially or unofficially put on hold in the past year (American Electric Power's Mountaineer Project, Basin Electric's Antelope Valley Project, and Tenaska's Taylorville Project) reinforce the idea that the financing of first-of-a-kind projects becomes more difficult in the absence of a clear long-term market.

Table 1. Status of U.S. Commercial-Scale CCS Projects on Coal-Fired Power Plants

Project	Technology	Federal Funding	Status
AEP Mountaineer	Pulverized coal (PC) with post-combustion capture	$334 million (CCPI R3)	On hold
Basin Electric Power Coop	PC with post-combustion capture	$100 million (CCPI R3)	On hold
Conoco-Phillips Sweeny Gasification	Integrated gasification combined cycle (IGCC) with capture	$3 million for project development	On hold
Tenaska Trailblazer	PC with post-combustion capture		On hold
Tenaska Taylorville	IGCC with capture	$2.58 billion loan guarantee and $417 million ITC	On hold
Future Gen 2.0	Oxyfuel combustion with capture	$1 billion	Unclear
Hydrogen Energy California	IGCC with capture	$308 million (CCPI R3)	Restructured under new ownership
Mississippi Power Kemper County	IGCC with capture	$270 million (CCPI R2) + $133 million in ITC	Broke ground
NRG WA Parish	PC with post-combustion capture	$355 million (CCPI R3)	Moving forward
Summit Power Texas Clean Energy Project	IGCC with capture	$450 million ($350 million from CCPI R3 and a separate $100 million grant)	Working to secure financing and long-term off-take agreements

AEP Mountaineer. Working with a number of collaborators including Alstom, DOE's National Energy Technology Laboratory, and Battelle Memorial Institute, American Electric Power

[10] MIT Energy Initiative: Carbon Capture & Sequestration Technologies. "Power Plant Carbon Dioxide Capture and Storage Projects." Accessed October 2011. http://sequestration.mit.edu/tools/projects/index.html
Associated Press. "FutureGen in talks over Ameren's role in project." November 12, 2011. http://www.chicagotribune.com/news/chi-ap-il-futuregen-ameren,0,6957365.story

successfully completed a CCS pilot project on a slip-stream equivalent to 20 MW of generating capacity from its 1.3 GW Mountaineer Station in New Haven, West Virginia. The second phase of the project was to scale the pilot project up to 235 MW at the same power plant. DOE had awarded the project up to $334 million to cover half of the scale-up project.[11] However, after not being able to secure cost recovery for the project from state regulators in West Virginia and Virginia, AEP terminated its agreement with DOE and placed its CCS plans on hold.[12]

The decisions by the regulatory bodies in West Virginia and Virginia reflect one of the challenges associated with building a demonstration plant: while the benefits of a commercial-scale project will be widely realized, the costs will be borne by the company building the plant and, in turn, the customers of the power plant. As the Virginia State Corporation Commission concluded:

> *It is reasonable for AEP to evaluate and explore options regarding potential federal legislation or regulation regarding GHG emissions. We do not find, however, that it was reasonable for [Appalachian Power Company (APCo)] to incur the Mountaineer CCS project costs and then seek recovery from Virginia ratepayers. For example: (i) although AEP asserts that this demonstration project will benefit customers of all of AEP's operating companies and of all utilities in the United States, APCo's ratepayers (and not shareholders) are being asked to pay for all of the costs incurred by AEP for this project; and (ii) as stated by Consumer Counsel, "AEP is undertaking no other [CCS] initiatives at any of its other subsidiaries' plants," and "APCo and its customers are being asked to shoulder the entire financial burden and risk associated with AEP's [CCS] research and development." Accordingly, we deny the Company's request for cost recovery of the Mountaineer CCS demonstration project under the facts presented herein.*[13]

In a press release announcing the decision, Michael Morris, AEP chairman and chief executive officer said:

> *[A]s a regulated utility, it is impossible to gain regulatory approval to recover our share of the costs for validating and deploying the technology without federal requirements to reduce greenhouse gas emissions already in place. The uncertainty also makes it difficult to attract partners to help fund the industry's share.*[14]

Separately, project partner, Alstom, reinforced these points:

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[11] MIT Energy Initiative: Carbon Capture & Sequestration Technologies. "Power Plant Carbon Dioxide Capture and Storage Projects." Accessed October 2011.
http://sequestration.mit.edu/tools/projects/index.html
[12] AEP. "AEP Places Carbon Capture Commercialization On Hold, Citing Uncertain Status of Climate Policy, Weak Economy," Press Release. July 14, 2011.
http://www.aep.com/newsroom/newsreleases/?id=1704
[13] Commonwealth of Virginia State Corporation Commission. Application of Appalachian Power Company, Case No. PUE-2009-00030. July 15, 2010.
[14] AEP. "AEP Places Carbon Capture Commercialization On Hold, Citing Uncertain Status of Climate Policy, Weak Economy," Press Release. July 14, 2011.
http://www.aep.com/newsroom/newsreleases/?id=1704

> *State and federal policy makers must recognize the long-term implications of failing to adopt policies that establish the economic certainty needed to drive development of low carbon energy technologies. In addition, policy makers should fund large scale demonstration projects and allow utilities to recover investments in such projects, which are essential if the industry is to move forward in de-carbonizing electricity in the most cost-effective manner possible.*[15]

Basin Electric. Basin Electric's Antelope Valley project was a proposed 120-MW slipstream from the 450-MW Antelope Valley Station in Beulah, ND. Basin Electric, working with HTC Purenergy, Burns and McDonnell, and Doosan Babcock proposed to demonstrate an ammonia-based post-combustion capture technology developed by HTC Purenergy. Despite a $100 million grant from DOE and a $300 million loan from the U.S. Department of Agriculture and projected revenue from the sale of CO_2 for enhanced oil recovery, the project was indefinitely put on hold in December 2010. Ron Harper, the chief executive officer and general manager of Basin Electric cited three factors in making the decision: the lack of a mature EOR market in North Dakota, uncertainty around environmental legislation, and the lack of a long-term U.S. energy strategy.[16]

Tenaska. As designed, Tenaska's Taylorville Energy Center project would be a 602-MW (net) integrated gasification combined cycle project. While not officially on hold, a bill that would have given Tenaska approval to recover costs from ratepayers was rejected by the Illinois Senate in January 2011.[17]

During a hearing held by the U.S. House of Representatives Natural Resources Subcommittee on Energy and Mineral Resources in June 2008, Tenaska's Gregory Kunkel, VP of Environmental Affairs, discussed the importance of long-term certainty in the context of another CCS project, the Trailblazer project in Sweetwater, TX:

> *Perhaps the most important thing Congress could do to facilitate the development of Trailblazer or similar carbon capture and storage projects, is to provide regulatory certainty, and in particular, a regulatory framework within which a market can develop that values greenhouse gas emission reductions. Without regulatory certainty and recognition of the value of emission reductions, developers are confronted with making multibillion dollar decisions in a policy vacuum. No developer can operate effectively while having to speculate on regulatory outcomes, especially outcomes so fundamental to the success of the enterprise.*
>
> *Accordingly, we have developed Trailblazer in anticipation of federal climate change legislation that would support, through placing a price on greenhouse gas emissions*

[15] Alstom. "Alstom Supports American Electric Power (AEP) Decision on Next Phase of Carbon Capture and Sequestration (CCS) Project," Press Release. July 14, 2011. http://www.alstom.com/us/news-and-events/press-releases/alstom-supports-aep-on-ccs-technology/
[16] Basin Electric. "Basin Electric Postpones CO2 Capture Project," Press Release. December 16, 2010. http://www.basinelectric.com/News_Center/Publications/News_Releases/Basin_Electric_postpones_CO2_capture_project.html
[17] Tenaska. "Illinois Senate Fails to Pass Taylorville Energy Center Legislation," Press Release. January 12, 2011. http://www.cleancoalillinois.com/press-110112.html

> *and other means, the significant capital and operating costs of carbon capture technology. Without climate legislation, it appears that revenues from enhanced oil recovery CO_2 sales will be insufficient to cover all carbon capture costs. With proposed climate legislation, projected compliance cost savings and other effects of climate change legislation, combined with EOR revenues, would provide the needed economic incentives to build and operate Trailblazer.* [18]

All of these projects had significant federal and state government support but that support was not enough to overcome the added costs of technology demonstration combined with long-term uncertainty.

New Technology (First Mover Risks)

The absence of a significant long-term market for baseload low-carbon electricity generation technologies increases the risks of investing in a demonstration plant and likely increases the costs of demonstration. Construction of any power plant requires the integration of complex technologies and carries with it the risk of project overruns and unexpected delays. Those risks are magnified when a project is demonstrating new technologies. Not only will designers and engineers have to deal with unexpected issues that arise during construction of large-scale systems but the entire supply chain will have to scale up technologies that may have only been proven at bench scale. Without timeline for construction beyond the current round of demonstration plants, developers and supply chain companies will be operating in an atmosphere where the project is likely to be one-of-a-kind. Such an environment increases the risk and cost of construction.

Despite the uncertainties, a number of commercial-scale demonstration projects continue to move forward. Two that have secured long-term revenue streams and have or are close to breaking ground are Southern Company's Kemper County IGCC Project in Kemper County Mississippi and Summit Power's Texas Clean Energy Project (TCEP) IGCC project in Ector County, Texas. Both of the projects have secured DOE grants and have announced long-term CO_2 purchase agreements for use in EOR.

The major difference between the two projects is that the Kemper County IGCC Project will be operated by Mississippi Power in a market regulated by the Mississippi Public Service Commission while the TCEP IGCC project will operate as a merchant generator. The Kemper County IGCC Project received approval from the Mississippi Public Service Commission to include cost recovery in the rate base starting in 2012 up to a total project cost of $2.88 billion.[19]

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[18] Kunkel, Gregory P. *Testimony before the U.S. House of Representatives Natural Resources Subcommittee on Energy and Mineral Resources*. June 12, 2008. http://www.tenaskatrailblazer.com/pdfs/080612-Tenaska-Kunkel-Testimony.pdf

[19] Public Service Commission of the State of Mississippi. *In Re: Petition of Mississippi Power Company for a certificate of public convenience and necessity authorizing the acquisition, construction, and operation of an electric generating plant, associated transmission facilities, associated gas pipeline facilities, associated rights-of-way, and related facilities in Kemper, Lauderdale, Clarke, and Jasper Counties, Mississippi*, Docket No. 2009-UA-14. May 26, 2010.

The TCEP IGCC project announced a 25-year power purchase agreement for 200 MW of power (from an expected electric power capacity of 214 MW) with CPS Energy, the municipally-owned natural gas and electric utility in San Antonio, Texas.[20] As an additional source of revenue, TCEP has also announced a long-term contract to sell over 700,000 tons of urea fertilizer annually that will be produced during the gasification process. In public statements, Summit Power officials have indicated that the business plan for TCEP does not require a federal price on carbon.[21]

Transport and Storage

Beyond the power plant, there are significant uncertainties associated with the construction and availability of pipelines and storage locations for CO_2. While there is a mature network of CO_2 pipelines in the U.S. and the estimated costs of transportation and storage are a small part of the cost of CCS, developers considering CCS will have to identify storage locations, such as saline formations or EOR opportunities, and determine the extent of piping that might be required to move the CO_2 from the power plant to the storage location. Early integrated projects in the U.S. are primarily focused on EOR opportunities, in part because of the existence of CO2 pipelines and experience with the storage formations. A number of companies with pipeline and EOR experience, such as Denbury Resources and Kinder Morgan, have been engaged in CCS demonstration projects.

Given the extensive technical and regulatory experience associated with pipeline transport of CO_2, it is unlikely the construction of CO_2 pipelines will be a significant barrier to CCS deployment. However, pipeline siting and availability considerations could be challenging for early projects that are not located near a storage location. In advance of CCS development, there are areas where state level rules and regulations could be streamlined to ease the development of CO_2 pipelines. For example, in some states oversight of CO2 pipelines is divided between different agencies.

On the storage side, there are a number of significant CO_2 storage projects in the U.S. and globally that have been demonstrating the storage of CO_2 at scale in saline formations, depleted gas reservoirs, and as a part of EOR. As these projects advance and continue to collect data, the geologic storage of CO_2 will be better understood and confidence in long-term storage will increase.

To further reduce the uncertainty associated with storage, EPA has finalized rules through the Underground Injection Control program to protect drinking water sources during the injection of CO_2 for storage in geologic formations. EPA has also finalized rules for the reporting of emissions from CO_2 storage location through the GHG Reporting Program that provide a starting point for CO_2 monitoring and verification. These rules help to establish the framework

[20] Summit Power. "Texas Clean Energy Project to Sell Power to CPS Energy in 25-year PPA," Press Release. June 20, 2011. http://www.summitpower.com/in-the-news/texas-clean-energy-project-to-sell-power-to-cps-energy-in-25-year-ppa/

[21] Goozner, Merrill. "Clean Coal: Lost Jobs, Wasted Money as Feds Dither," *The Fiscal Times*. September 29, 2011. http://www.thefiscaltimes.com/Articles/2011/09/29/Clean-Coal-Lost-Jobs-Wasted-Money-as-Feds-Dither.aspx?p=1

within which future projects will operate. In addition, the California Carbon Capture and Storage Review Panel identified the following regulatory gaps:

- Rules to protect non-groundwater environmental and mineral rights;
- Legal requirements regarding atmospheric emissions of CO_2;
- Appropriateness of the monitoring and verification requirements under the GHG Reporting Program for GHG reduction programs.[22]

A significant source of uncertainty in the development of CCS is ownership of pore space for CO_2 storage. The rules associated with the ownership of pore space vary from state to state. Some states having a history of mineral severance, with established rules and procedures for separating subsurface rights from surface rights, while other states have no such experience and ownership remains with the surface owner.

In anticipation of CCS development, Wyoming and North Dakota have passed legislation to clarify the issues of pore space ownership. Wyoming assigned ownership of all pore space (defined as the subsurface space which can be used as storage space for carbon dioxide or other substances) to the surface owner. Wyoming further clarifies that historic agreements conveying mineral rights do not convey ownership of pore space "unless the agreement explicitly covers that ownership interest." North Dakota similarly defines pore space and clarifies that surface owners retain pore space ownership. Unlike Wyoming, North Dakota does not provide for the severance of the pore space from surface ownership. In both statutes, the states create a system whereby consent of pore space owners is necessary to begin CO_2 sequestration. In Wyoming, 80 percent of owners must consent, in North Dakota, 60 percent of owners must consent.[23]

Long-term Stewardship Risks

Once CO_2 is injected into a formation for long-term sequestration, the intent of all parties will be for it to remain underground indefinitely. There are a number of concerns associated with long-term sequestration including who is responsible for potential risks to health, safety, and the environment and who is responsible for keeping CO_2 out of the atmosphere under a cap-and-trade or other regulatory regime. The challenge for legislators and regulators developing frameworks to address these types of liability is to sufficiently reduce any project risk to make the projects financially attractive while maintaining a level of responsibility that encourages owners and operators to operate in a way that promotes safe long-term sequestration.

Stakeholders at the state and federal level have started to develop frameworks to address the challenges associated with long-term stewardship and liability. For example, Louisiana, Montana, North Dakota, and Oklahoma have developed a model where the operator of a geologic sequestration site can transfer title and liability to the State after demonstrating that the site is stable. FutureGen Alliance, the industrial coalition formed to support the original DOE-sponsored FutureGen project to build an integrated CCS facility, included a request for

[22] California Carbon Capture and Storage Review Panel. *Findings and Recommendations*, December 2010.
[23] Vann, Adam, James E. Nichols, Paul W. Parfomak. *Legal Issues Associated with the Development of Carbon Dioxide Sequestration Technology*, Congressional Research Service, March 19, 2010.

states to indemnify the project in its request for proposal. The two states with sites in contention at the end of the process, Texas and Illinois, both passed legislation that would provide indemnification for the project. While the language in the legislation was specific to the FutureGen project and not applicable to other projects, this step suggests that states are willing to consider indemnifying certain projects.

At the federal level, a number of bills have been introduced into Congress in recent years that provide funding for large-scale CCS demonstration projects and also provide liability protection and federal indemnification for funded projects. The most recent draft of the legislation (S. 699) was introduced by Senator Bingaman in March 2011 and reported out of committee in July. While it is unlikely that Senator Bingaman's bill will be voted on by the Congress, the bill will likely be the framework for future attempts to address liability concerns through legislation. Appendix B includes a summary of S. 699.

Any approach to addressing long-term liability raises questions about the timeframes associated with monitoring and tracking CO_2. If a state or the federal government is going to indemnify a company that sequesters CO_2, when does that indemnification start? If a contract is structured so that the seller has to cover any potential leakage, how long into the future does the seller have to monitor the location? Is the owner or operator of a site responsible for leakage that could occur in 100 years, 1,000 years, or even 10,000 years?

While there are not clear answers to these questions, there is general agreement that the risk profile of a site declines significantly after injection ends. During injection, CO_2 is displacing fluids and creating a pressure front within a geologic formation. If there are unexpected leakage pathways or if there is unanticipated movement of the CO_2, it will likely happen during injection. Once injection ceases, geologists expect the risk of unexpected movement to decrease and the CO_2 to remain trapped by primary trapping mechanisms such as a cap rock. Over longer time frames, geologists expect the risk profile to decrease even further as the CO_2 becomes even more encumbered through secondary mechanisms such as dissolution into the fluid in the formation, capillary trapping in the formation pore space, and mineralization. If this model for risk is correct, the need for monitoring and verification should drop considerably during the post-injection period. A long-term stewardship framework will most likely be built on the testing and verification of this risk profile.

Developing a Business Case for NG-CCS

The business case for CCS on natural gas combined cycle plants is based on getting a reasonable return on the investment in a natural gas combined cycle unit with CCS. In a regulated market, this means the public utility commission allows the company to build these additional risks into the rate. In a deregulated market, this means the wholesale market is priced in a way to allow cost recovery for these additional risks.

To address the additional risks and encourage deployment of CCS on natural gas combined cycle units, policymakers can use mechanisms that either shift the supply curve or shift the demand curve. To reduce the cost of the technology and shift the supply curve, policymakers can fund research, development, and demonstration (RD&D) and facilitate knowledge transfer through

sponsorship or organization of conferences and trade publications. To shift the demand curve, policymakers can develop regulations that create a market for the technology such as cap-and-trade systems, standard setting, or portfolio standards.

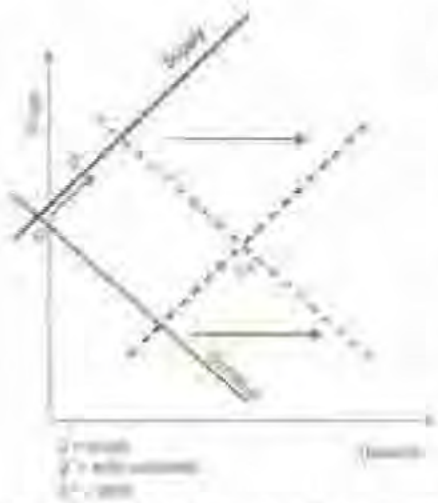

Figure 5. Idealized Supply and Demand Curve

Ideally, policymakers will use a continuum of policies that lower the cost of the technology while creating a long-term market. Figure 5 shows an idealized supply and demand curve. If the current state of the technology is at point Q (i.e. the equilibrium point is no demand), subsidies can make it economically attractive to demonstration the technology (moving along the supply curve to Q'). The goal of these subsidies should be to move the supply curve through learning-by-doing. Moving the supply curve means that a greater number of CCS power plants will be deployed at a given price. At the same time, policy makers should be creating a market for the technology to shift the demand curve and encourage a new equilibrium point (Q*) where more of the technology is deployed at a lower price.

Lowering Costs (Moving the Supply Curve)

Lowering the cost of CCS deployment could come in many forms: funding research in the hopes of technology breakthroughs, lowering the risks associated with the technology by subsidizing early demonstration projects, increasing regulatory certainty associated with CO_2 storage and long-term assurance, and encouraging stakeholder collaboration.

Considerable federal dollars have been committed to demonstration projects. The American Recovery and Reinvestment Act (ARRA) of 2009 included $3.4 billion to DOE for the Fossil Energy Research and Development program. The funding was directed to a number of different initiatives:

- $1 billion for fossil energy research and development programs, which was later committed to funding the revised FutureGen Project (FutureGen 2.0);
- $800 million for the Clean Coal Power Initiative Round III (CCPI R3) Funding Opportunity Announcement;
- $1.52 billion for a competitive solicitation for industrial carbon capture and energy efficiency improvement projects, including beneficial CO_2 reuse;
- $50 million for site characterization activities in geologic formations;
- $20 million for geologic sequestration training and research grants; and
- $10 million for program direction funding.

Before receiving money under ARRA, CCPI R3 had $600 million in existing funding. Bringing the total available under CCPI R3 to $1.4 billion. Five awards were made under CCPI R3:

- $100 million to Basin Electric Power Coop for post-combustion capture;
- $308 million to Hydrogen Energy International LLC for IGCC with CCS;
- $334 million to American Electric Power for post-combustion chilled ammonia capture;
- $350 million to Summit Texas Clean Energy for IGCC with pre-combustion capture; and
- $295 million to Southern Company for retrofit post-combustion capture. Southern Company declined the grant in February 2010. Recently, DOE announced that an NRG Energy-led project would receive $355 million for a 240 MW post-combustion demonstration project in Texas.

However, the lack of demand-focused policies decreases the effectiveness of the technology push policies. As discussed above, since late 2010, the Basin Electric and AEP projects have been put on hold. The Hydrogen Energy project has been significantly restructured and recently unveiled a new project plan under new leadership from SCS Energy.[24] In November 2011, the NRG Energy project was expanded from 60 MW to 240 MW with a goal of increasing EOR revenues to make up for the lack of a carbon price. As a part of the project, NRG Energy will construct a new 80-MW gas-fired combustion turbine to generate heat for the capture process. While the combustion turbine will be a significant capital expense, NRG Energy's goal is to reduce the parasitic losses to the coal plant.[25]

DOE has had significant success encouraging knowledge sharing and stakeholder interaction through the Regional Carbon Sequestration Partnerships and annual conferences. EPA has been working to address regulatory uncertainties through the UIC rule and the GHG Reporting Program requirements.

Increasing Demand for NG with CCS

Increasing the demand for CCS could come in the form of tax incentives and loan guarantees; a national, regional, or state program developed through legislation (cap-and-trade program, portfolio standard, carbon tax); or a national or state regulatory program (greenhouse gas standards).

Existing federal programs designed to encourage a market for CCS are in the form of tax incentives and loan guarantees. The Emergency Economic Stabilization Act of 2008 established tax incentives for CCS and EOR. The incentives provided a $20 credit per metric ton CO_2 captured, transported, and securely stored for geologic sequestration and $10 credit per metric ton CO_2 for EOR with secure geologic storage. Qualified facilities must capture at least 500,000 tons of CO_2 per year. The credit is capped after the first 75 million tons. Additionally, the Act established a 30% investment tax credit for advanced coal-based generation technology projects. Total awards are capped at $1.25 billion and qualified projects can be IGCC or pulverized coal with CCS and must sequester at least 65% of total CO_2 emissions.

[24] SCS Energy. "SCS Energy Close Deal to Acquire HECA Project in Kern County," Press Release. September 28, 2011.
[25] Bandyk, Matthew. "NRG expanding carbon capture project in Texas," *SNL Energy*. November 30, 2011.

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[24] SCS Energy. "SCS Energy Close Deal to Acquire HECA Project in Kern County," Press Release. September 28, 2011.
[25] Bandyk, Matthew. "NRG expanding carbon capture project in Texas," *SNL Energy*. November 30, 2011.

The Energy Policy Act of 2005 authorized loan guarantees for projects using innovative technologies to reduce GHG emissions from coal-based energy sources. DOE published a solicitation in Sept 2008 for up to $8 billion of loan guarantees in support of debt financing for integrated CCS systems and advanced coal gasification.

As discussed above, the biggest impediment to deployment of CCS on power plants is the lack of certainty around future greenhouse gas regulation. The projects in Table 1 were proposed in an environment where early-mover CCS projects had the potential to earn significant revenues through comprehensive climate legislation. In addition to putting a price on GHG emissions, the American Clean Energy and Security Act of 2009, as passed by the House, established a bonus allowance program to support the commercial deployment of CCS technologies. The program included a number of elements that balanced the need to provide near-term incentives while signaling that the support would phase out over time; however its focus was on coal-based power.

The bonus allowance program was limited to 72 GW of total cumulative generating capacity (including industrial applications). To be eligible a project had to implement CCS technology at an EGU with a nameplate capacity of 200 MW or more that derived 50 percent of its annual fuel input from coal, petroleum coke (a byproduct of the refining process), or any combination of the two fuels and captures and sequesters at least 50 percent of emitted CO_2 on an annual basis. The Act also included restrictions on bonus allowance eligibility for facilities initially permitted after January 1, 2009 and before January 1, 2020 if they do not capture 50 percent of CO_2 when they commence operation. The companion bill in the Senate, which never made it to the floor for a vote, would have refined these conditions to incentivize early deployment but limit the bonus pool after 2020.

Review of GHG Control Programs

Despite the absence of comprehensive Federal legislation to control GHG emissions, GHG emissions are regulated at the state level by the states participating in the Regional Greenhouse Gas Initiative (RGGI) and California. However, the stringency of these programs is not yet sufficient to drive development of CCS.

EPA has also started regulating GHG emissions from the electric sector as part of the facility permitting process (requiring the use of best available control technologies (BACT) for regulated pollutants) and is expected to release new source performance standards (NSPS) for GHG emissions from power plants in the coming months.

Regional Greenhouse Gas Initiative

The RGGI regional budget was established using a baseline of 2000 to 2004, which was then increased to account for the expected growth in emissions until the program launched in 2009. The budget was apportioned among the states. Since the cap was set, emissions in the RGGI region have declined significantly due to a variety of energy market dynamics. In 2010, emissions were approximately 27 percent below the regional cap. The discrepancy is the result of increased natural gas generation because of lower relative natural gas prices; increased

generation by non-emitting resources, such as nuclear, renewable, and hydro plants, along with lower electricity demand due to the recession and energy efficiency efforts.[26]

With emissions projected to remain well below the regional cap for the foreseeable future, the cost of RGGI allowances is expected to remain at the auction reserve price of $1.86 per ton. The announcement in May 2011 by Governor Chris Christie of New Jersey that the state would leave RGGI at the end of 2011 and uncertainty regarding the continued participation of New Hampshire, Maine, and New York has further weakened demand for allowances. Given these dynamics, as it is currently designed, RGGI will not create a market demand for CCS on natural gas plants.

RGGI states are allowed significant leeway in how they allocate the value associated with their CO_2 emission allowances. Under the original RGGI Memorandum of Understanding, the states agreed that they would use at least 25 percent of the allowance value for a "consumer benefit or strategy energy purpose." Since the states elected to auction the vast majority of allowances, they have received substantial revenues, but most of the funds have been directed toward energy efficiency and renewable energy programs, rather than supporting the development of new low-carbon technologies.[27]

New York is the only state that allocated any RGGI auction revenues to support research, development, and deployment of CCS technologies. The state has allocated about $1 million for the TriCarb Consortium for Carbon Sequestration, which is working to identify potential geologic sequestration sites in Rockland County, New York.[28]

California

In 2006, California passed SB1368, which required the California Energy Commission (CEC) and Public Utilities Commission (CPUC) to establish an Emissions Performance Standard (EPS) for baseload generating resources. The EPS applies to distribution utilities and is designed to prevent these entities from making long-term investments in high-emitting baseload power plants. Long-term investments covered by the EPS include: construction of new units, expansion or purchase of equity share in existing units, and signing new long-term power purchase agreements.[29]

The EPS was set at 1,100 pounds of CO_2 per MWh. While this emission rate precludes long-term investments in coal-fired power plants without CCS, it is readily achievable by new natural gas

[26] Environment Northeast. *RGGI Emissions Trends Report*. May 2011. http://www.env-ne.org/resources/open/p/id/1109/from/331
[27] Regional Greenhouse Gas Initiative. *Memorandum of Understanding*. December 2005. http://www.rggi.org/docs/mou_final_12_20_05.pdf
[28] New York State Energy Research and Development Authority. *Operating Plan for Investments in New York Under the CO_2 Budget Trading Program and CO_2 Allowance Auction Program*. June 2010. http://www.nyserda.org/RGGI/RGGI_Report_June.pdf
[29] California Energy Commission. Emissions Performance Standard. http://www.energy.ca.gov/emission_standards/index.html

combined cycle units. There are currently no plans to revise the EPS to a level that would drive investment in CCS for gas-fired power plants.[30]

California is scheduled to launch the first phase of its cap-and-trade program on January 1, 2013. At the outset, the program will cover the electric sector, including electricity imports, and large industrial sources. Unlike RGGI, the California cap is expected to be relatively stringent and could begin forcing reductions immediately.

In addition to the potential demand for reductions, the program starts with an allowance price floor of $10 per ton in 2013. The price floor then increases by 5 percent plus inflation each subsequent year. Assuming that the program exists as currently proposed, the minimum allowance price would reach nearly $18 per ton in real 2013 dollars by 2025.[31] The combination of the increasing price floor and potential demand for reductions could create an attractive environment for natural gas CCS in the medium-term.

California has a long-term target to reduce GHG emissions by 80 percent below 1990 levels by 2050. Achieving this goal will require contributions from all sectors of the economy, and the electric sector can be expected to provide some of the greatest reductions, given the relative abundance of low emission technologies, as compared with other sectors. The December 2010 study by the California Carbon Capture and Storage Review Panel acknowledges that in order to realize the state's long-term target emissions natural gas plants will eventually have to reduce their emissions or be phased out.

The review panel identified project financing as a key barrier to development and made the following recommendations[32]:

- *It should be State policy that the burdens and benefits of CCS be shared equally among all Californians. Toward this end, the permitting authority shall endeavor to reduce, as much as possible, any disparate impacts to residents of any particular geographic area or any particular socioeconomic class.*
- *The State legislature should establish that any cost allocation mechanisms for CCS projects should be spread as broadly as possible across all Californians.*
- *The State should evaluate a variety of different types of incentives for early CCS projects in California and consider implementing those that are most cost-effective.*

CCS as part of the Best Available Control Technology (BACT) selection process

Based on its interpretation of the Clean Air Act (CAA), as of January 2, 2011, EPA requires owners and operators of new or modified power plants to include control of GHG emissions in

[30] Van Atten, Chris. "Choices in Air Pollution Regulation: A Review of Alternative Air Emissions Policy Structures for the Electric Sector," *Report for the American Clean Skies Foundation*. February 23, 2011. http://www.cleanskies.org/wp-content/uploads/2011/05/AEPS_ACSF_22Feb2011.pdf
[31] California Air Resources Board, *California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms*, October 2011. http://www.arb.ca.gov/regact/2010/capandtrade10/ctfro.pdf
[32] California CCS Review Panel, *Findings and Recommendations by the California Carbon Capture and Storage Review Panel*, December 2010. http://www.climatechange.ca.gov/carbon_capture_review_panel/documents/2011-01-14_CSS_Panel_Recommendations.pdf

prevention of significant discharge (PSD) and Title V air quality permit applications. PSD permits require applicants to identify BACT for regulated pollutants. In November 2010, EPA released guidance on the process for identifying and selecting technologies as BACT (the guidance was updated in March 2011).[33]

In the guidance, EPA recommends, but does not require, the use of the Agency's five-step "top-down" BACT process that is currently used for other PSD pollutants. The top-down process involves determining all available control options, ranking them by effectiveness, and then examining them individually, beginning with the most effective. The resulting control option is chosen as BACT unless the permit applicant satisfactorily demonstrates that it should be disqualified from consideration based on technical considerations or its energy, environmental, or economic impacts. If the top-ranking option is disqualified, the next most effective control option is considered, and so on, until an option has been selected as BACT.

In summary, the five-step BACT process is:

1. Identify all available control technologies.
2. Eliminate technically infeasible options.
3. Rank remaining technologies.
4. Evaluate most effective controls.
5. Select BACT.

EPA notes that while the guidance discusses some preliminary views on specific issues relating to determining BACT for GHGs, it does not give any final determinations of BACT for a particular source. The process requires a case-by-case analysis.

Within the guidance, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO_2-emitting facilities, including fossil fuel-fired power plants. EPA says that CCS "merits initial consideration"[34] and should be included in Step 1 of the BACT determination, although it may be excluded in later steps as a result of considerations such as feasibility and cost.

EPA specifically discusses the technical feasibility of CCS, noting, "[w]hile CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases."[35] EPA recognizes that there are significant logistical hurdles and technical hurdles that may be involved in installing and operating a CCS system that may lead to its disqualification in Step 2. If other sources in the category have already applied CCS technology, or if the source is located in an area where transportation and sequestration opportunities already exist, a detailed analysis would probably be needed to exclude CCS in Step 2.

EPA also discusses CCS with respect to economic concerns, noting, "at present CCS is an expensive technology"[36] and based on its current costs, it will often be eliminated in Step 4 of the

[33] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011 (Update). http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf
[34] Ibid at p. 33.
[35] Ibid at p. 36.
[36] Ibid at p. 42.

analysis, if not before. However, EPA notes that there may be cases where the economics of CCS are more favorable, and research and development may render CCS more cost-effective.

In the initial permits for NGCC units that include GHG emissions, the focus has been on maximizing the efficiency of the unit through advance turbine technology. Consideration of CCS has followed EPA's guidance and the technology has not emerged as BACT. Given the slow pace of CCS development in the U.S., it is unlikely that the PSD or Title V permitting process, as currently structured, will drive use of CCS on natural gas units.

CCS as part of the New Source Performance Standard (NSPS) process

EPA is currently developing NSPS for GHG emissions from electric generating units under the CAA. Since GHG emissions are not regulated as toxic air emissions and EPA has not set a national ambient air quality standard for GHG emissions, the CAA requires EPA to set standards for existing as well as new and modified sources under the NSPS program. Once proposed, the new source standards will set a floor (i.e., the minimum standard new sources must meet) for GHG BACT.

EPA's schedule for proposing GHG NSPS is driven by a settlement agreement with a number of environmental litigants. Originally, EPA agreed to propose standards for new, modified, and existing sources by July 26, 2011 and finalize standards by May 26, 2012. That schedule has slipped a number of times. EPA and the litigants are expected to reach an agreement on a new schedule by the end of November 2011.

The standards for new and modified sources are intended to "reflect the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[37] This provides EPA with significant discretion in determining an appropriate standard. The standards are traditionally set at the unit level and states do not have the flexibility to approve less stringent standards.

The CAA provides EPA with considerable flexibility in establishing standards for existing sources. EPA is required to establish emission guidelines for states that provide a procedure for states to issue performance standards. States are required to develop implementation plans to regulate existing sources in a way that complies with the guidelines. A number of observers have speculated that states could propose the use of new or existing cap-and-trade programs as the basis for compliance with the emission guidelines.[38]

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[37] EPA. *Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act*, 2010. http://www.epa.gov/airquality/pdfs/111background.pdf

[38] See for example the February 2011 Working Paper, *What's Ahead for Power Plants and Industry? Using the Clean Air Act to Reduce Greenhouse Gas Emissions, Building on Existing Regional Program* by Franz T. Litz and Nicholas M. Bianco of World Resources Institute and Michael B. Gerrard and Gregory E. Wannier of Columbia Law School, http://www.law.columbia.edu/null/download?&exclusive=filemgr.download&file_id=542077

It is unclear what standards EPA will propose under GHG NSPS. From the perspective of creating markets for CCS, EPA could determine that CCS is the best system of emission reduction for new fossil fuel-fired power plants. However, such a determination would be a departure from the focus on energy efficiency found in the GHG BACT guidance and would raise questions about how EPA considered costs in setting the standard. If EPA allows existing state or regional programs to be used to meet emission guidelines, those programs would have to be significantly more stringent than existing programs to drive the installation of CCS on existing power plants.

Impact of Incentives on Financing a Model NGCC Plant

Absent a GHG program that is sufficiently stringent to create a market for CCS technologies, the demonstration and deployment of CCS on NGCC power plants will depend on incentives such as grants and tax credits. As a way of reviewing the impact of subsidies on CCS deployment on NGCC power plants, MJB&A developed a financial model using technical and cost assumptions for NGCC with and without CCS. The data were based on analysis done by the Department of Energy's National Energy Technology Laboratory (NETL) for its series of reports *Cost and Performance Baseline for Fossil Energy Plants*.[39]

Table 2 summarizes NETL's assumptions. Note that the two units have different net power outputs (555 MW for the non-capture unit compared to 474 MW for the capture unit) but NETL designed them to consume natural gas at the same rate (167,333 pounds per hour). MJB&A assumed a three-year construction period followed by 32 years of operating life for each plant for a total project period of 35 years.

Table 2. DOE NETL Technical and Cost Assumptions for NGCC and NGCC with CCS

Parameter	Unit	NGCC (Advanced F Class)	
		No Capture	With Capture
Capture Rate	%	0%	90%
Capacity Factor	%	85%	85%
Gross Power Output	kWe	564,700	511,000
Auxiliary Power Requirement	kWe	9,620	37,430
Net Power Output	kWe	555,080	473,570
Natural Gas Flowrate	lb/hr	167,333	167,333
HHV Thermal Input	kW(th)	1,105,812	1,105,812
Net Plant HHV Efficiency	%	50.2%	42.8%
Net Plant HHV Heat Rate	Btu/kWh	6,798	7,968
Total Plant Cost	2007$/kW	584	1,226

The list of model inputs shown in Table 3 was developed using NETL's technology and cost assumptions and other assumptions based on MJB&A's own energy market analysis. As a way

[39] DOE NETL, *Cost and Performance Baseline for Fossil Energy Plants: Volume 1 – Bituminous Coal and Natural Gas to Electricity (Rev. 2)*, November 2010.

to understand how to make NGCC with CCS financially viable, MJB&A analyzed the levelized cost of electricity (LCOE) and then developed estimates of the revenue generation from electricity sales as well as potential subsidies. A key difference to the NETL work is their significantly higher base case fuel cost assumption – $6.55 per MMBtu compared to $5.00 per MMBtu in this analysis. Analysis of potential revenues was beyond the scope of the NETL analysis.

Table 3. Model Revenue and Expense Assumptions

Discounted cash flow components (2007$)	Unit	No Capture Year 0	With Capture Year 0
Revenues (revenue sufficiency)			
Inflation - electricity price	%	3.0%	3.0%
Wholesale electricity price	$/kWh	0.045	
Expenses			
Inflation rate - variable costs	%	3.0%	3.0%
Fuel cost	$/MMBtu	5.00	
Fixed O&M	$/kW-yr	26.3	49.9
Variable O&M	$/kWh	0.00130	0.00260
Capital cost	$	404,889,900	764,967,000
CO_2 TS&M	$/ton	0	8.09
Capex period	years	3.00	3.00
Distribution of capex	%/year	10, 60, 30	10, 60, 30
Escalation of capital costs	%	3.6%	3.6%
Equity cost[40]	%	12.0%	12.0%
Debt cost	%	4.5%	4.5%
Tax rate[41]	%	38.0%	38.0%
Debt %	% of total capital	50%	50%
WACC	%	8.3%	8.3%
Depreciation period	years	20	20

Table 4 summarizes the results of MJB&A's levelized costs and benefits analysis. The goal is to compare levelized costs and revenues, and determine how much subsidy revenue is needed to cover the costs.[42] In a scenario where wholesale electricity prices average 4.5 cents per kilowatt-hour (kWh) and increase at three percent annually over the life of the facility, the plants will

[40] Equity cost reflects the financial returns expected by equity investors in a CCS project. Equity cost is also referred to as a "hurdle rate" for investors. If an investor does not expect to earn his required rate of return, then he will not make his capital available to a project. Equity costs, therefore, must be reflected in the project economics, since they are needed in order to attract equity investors. Equity and debt costs together make up the weighted average cost of capital (WACC).
[41] Projected tax liabilities reflect estimated state and federal corporate marginal tax rates. A developer's unique tax situation may cause his actual tax rate to deviate from expected levels, but we assume that the project is taxed at the normal corporate rate.
[42] The levelized cost analysis includes capex and operating costs for the life of the project, as well as taxes and capital costs for both equity and debt, and therefore reflects developers' required rate of return.

earn levelized revenues of about $69 per megawatt-hour (MWh) or about 6.9 cents per kWh. This compares to an LCOE of about $68 per MWh for the no capture plant and about $95 per MWh for the plant with capture. In this scenario, the plant without capture would be economic while the plant without capture would not. Note that the LCOE difference between the capture and no capture plants ($27 per MWh) is in line with the estimates shown in Figure 3. At a fuel cost of $6.55 per MMBtu, as was used in the NETL analysis, the MJB&A no capture and capture estimates would be $84 and $115, respectively.

Table 4. Levelized Costs and Benefits for Model Plants

Component	No Capture ($/MWh)	Capture ($/MWh)
Net Levelized Costs	67.6	95.0
Capital costs	7.2	16.0
Fuel costs	52.9	65.7
F&VOM	7.5	10.1
Transport, Storage and Monitoring	0.0	3.1
Net Levelized Benefits From Electricity Sales	68.8	68.8

To review the impacts of grants and incentives based on CO2 stored on the financing of the capture project, MJB&A added a grant equal to 50 percent of the capital cost of the plant with carbon capture. For the model plant, this is equivalent to a $382.5 million grant, which is in line with the grants awarded to the two projects moving ahead ($403 million in the form of a grant and an investment tax credit to the Kemper County IGCC project and $450 million in grants to the Summit Power TCEP). Additionally, we looked at the impact of a credit equivalent to $20 per metric ton of CO2 (increasing with inflation at three percent annually) stored over the operating life of the project. Annually, MJB&A projected the model plant with CCS to capture and store 1.34 million metric tons of CO2, or about 44 million metric tons over the assumed 32-year operating life. The current geologic sequestration tax credit is capped at 75 million metric tons for *all* U.S. projects, which means that the modeled project on its own would use over half of the available tax credit. The actual benefit from that tax credit is therefore severely limited and it is unlikely that a single project would be able to absorb such a large share of the available tax credit. If current CCS projects continue to move forward and the use of CO2 for EOR expands, the tax credit pool will soon be depleted.

Figure 6 shows the results of MJB&A's analysis. With revenue from electricity sales starting at 4.5 cents per kWh, a grant equivalent to 50 percent of the capital requirement, and a tax incentive equal to $20 per metric ton of CO2 stored over the operating life of the plant, the CCS project is still not able to cover its costs.

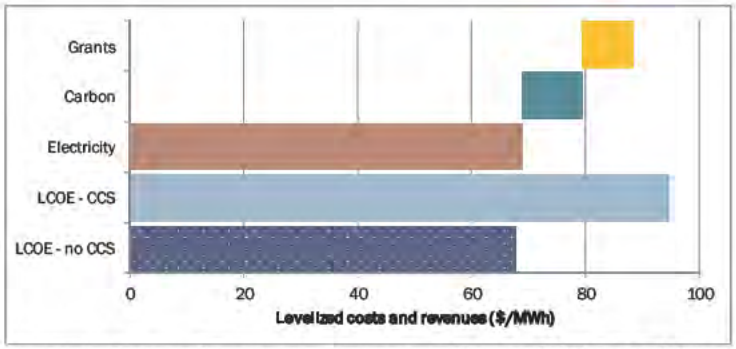

Figure 6. Cost and Revenue Comparison for Model NGCC Plants

As a way of exploring the sensitivity of LCOE to changes in CO2 credit value (carbon price); natural gas price; the weighted average cost of capital (WACC); operating and maintenance (O&M) costs; and transportation, monitoring and storage (TM&S) costs, MJB&A created high- and low-case scenarios for each variable. Figure 7 shows the results of this analysis. In Figure 7, the numbers in bold represent the base case assumptions described above; the values on either side of the bars represent low and high scenario assumptions. Carbon revenues, shown as negative, would offset the costs. The larger the rectangle, the more significant the values are to the LCOE. Within a reasonable range of assumptions, both the CO2 price and the fuel cost can significantly impact the LCOE of a project. As with any power plant, a CCS plant would benefit from entering into a long-term contract as a way of reducing fuel price risk. On the incentive side, with reasonable assumptions a significant long-term price on carbon has greater potential to help a project than loan guarantees or other mechanism that lower the cost of capital.

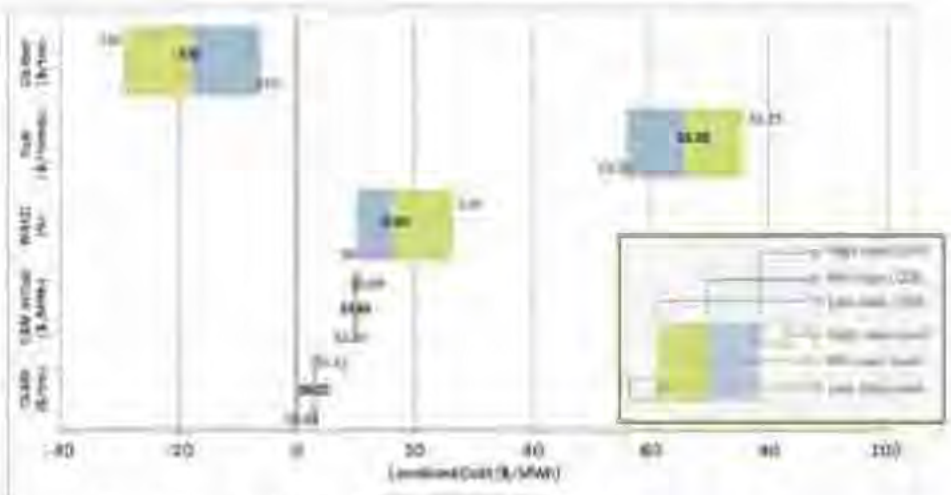

Figure 7. Sensitivity of LCOE to Changes in Key Variables

A volumetric, performance-based incentive like a long-term CO2 price would also be attractive because it rewards the desired action (i.e., storage of CO2) and not simply the construction of a plant.

For the model plant, a CO2 price of $50 per metric ton stored would be required to make the plant economically attractive. This price is lower than normally suggested in the literature but it represents payment for CO2 stored as opposed to CO2 avoided. Capture plants have to combust more fuel to generate the same amount of electricity. As a result, the baseline emissions, before capture, are higher on a per kWh basis, making the total captured greater than the total avoided. Under a comprehensive climate change policy, dollars per CO2 avoided would be the appropriate metric for compensation. The MJB&A model suggests a breakeven net CO2 production cost of $78 per metric ton. A probabilistic analysis completed by Professor Ed Rubin at Carnegie Mellon University suggests that a price in excess of $100 per metric ton would be required to induce CCS given the uncertainties around technology and policy.[43]

Conclusions

Deploying CCS at the scale required to impact climate change will require policy drivers as well as technological development. A key hurdle is the demonstration of CCS at a commercial scale power plant. Such a demonstration would increase confidence in the technologies and reduce costs through learning. While companies have successfully demonstrated the component technologies commercially (e.g., capture and separation to generate food-grade CO_2, transport of CO_2 from natural sources to oil wells in West Texas, and injection into geologic formations after stripping CO_2 from natural gas at the Sleipner Project in the North Sea), no one has constructed a full scale power plant with integrated CO_2 capture, transport, and geologic sequestration.

Over the past year, a number of integrated commercial-scale power plants with CCS have been put on hold. This trend was anticipated by the final report of the Interagency Task Force on Carbon Capture and Storage. The CCS Task Force concluded:

> *The lack of comprehensive climate change legislation is the key barrier to CCS deployment. Without a carbon price and appropriate financial incentives for new technologies, there is no stable framework for investment in low-carbon technologies such as CCS. Significant Federal incentives for early deployment of CCS are in place, including RD&D efforts to push CCS technology development, and market-pull mechanisms such as tax credits and loan guarantees. However, many of these projects are being planned by the private sector in anticipation of requirements to reduce GHG emissions, and the foremost economic challenge to these projects is ongoing policy uncertainty regarding the value of GHG emissions reductions.*[44]

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[43] Rubin, Edward, *The Cost of CCS for Natural Gas-Fired Power Plants*, Presentation to the Natural Gas CCS Forum, Washington, DC. November 4, 2011. http://www.cleanskies.org/wp-content/uploads/2011/11/ERubin_CCSandGasForum_1142011.pdf
[44] Interagency Task Force on Carbon Capture and Storage, August 2010. http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf

Policies to Advance the Business Case for NGCC with CCS

In a time of fiscal constraints and policy uncertainty, the greatest challenge to demonstrating CCS on a commercial scale may be finding the funding to overcome the significant financial obstacles. One approach that is currently gaining currency at DOE and elsewhere, is utilizing CO_2 for enhanced oil recovery.[45] However, at the reported contract prices for CO_2 for EOR (ranging from $20 to $40) additional sources of funding will be needed to make a commercial-scale power plant project viable.

In the absence of commercial-scale demonstration, policymakers should provide continued support for R&D to reduce the costs associated with CCS and should support initiatives to remove the legal and regulatory barriers to CCS, including work to reduce uncertainty around transport, storage, and liability.

One significant takeaway from ongoing efforts is a relative lack of focus on CCS for natural gas. Globally, the most advanced project is the Mongstad Project in Norway.[46] Domestically, the California Energy Commission in collaboration with WESTCARB, Pacific Gas & Electric, and Lawrence Livermore National Laboratory has initiated a study of the potential for NGCC with CCS in California.[47] That study is funded by DOE and is expected to get underway by the end of 2011, with results in 2012.[48]

When compared to coal-fired power plants, NGCC power plants have significantly lower GHG emissions per unit of electricity generation relative to coal-fired power plants.[49] However, to meet stringent mid-century GHG reduction targets, emissions from NGCC power plants will have to be dramatically reduced. As the National Petroleum Council concluded in its recent *Prudent Development* report:

> *However, under a more aggressive 80% GHG reduction target, natural gas, even with its relatively lower carbon intensity, cannot meet the carbon constraints alone without low to zero-emitting technologies such as CCS. Hence, it is imperative that research, development, and demonstration (RD&D) efforts related to lower-carbon technologies, including CCS, continue if a steep, long-term target is established and substantial natural gas use is to be maintained over the longer term.*[50]

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[45] See, for example, the National Enhanced Oil Recovery Initiative (http://www.pewclimate.org/initiatives/eor) and DOE NETL's recent report on "Next Generation" CO2-EOR opportunities (http://www.netl.doe.gov/energy-analyses/pubs/NextGen_CO2_EOR_06142011.pdf)
[46] MIT Carbon Capture & Sequestration Technologies. *Statoil Mongstad Fact Sheet: Carbon Dioxide Capture and Storage Project*. Updated November 16, 2011. http://sequestration.mit.edu/tools/projects/statoil_mongstad.html
[47] Gravely, Mike. *Assessment of Natural Gas Combined Cycle (NGCC) Plants with CO2 Capture and Storage,* Presentation to California Energy Commission. January 14, 2010. http://www.energy.ca.gov/contracts/2010-01-14_westcarb/presentations/01_Mike_Gravely_CEC.pdf
[48] MJB&A conversation with participants from Pacific Gas & Electric. October 2011.
[49] Staple, Gregory C. and Joel N. Swisher. *The Climate Impact of Natural Gas and Coal-fired Electricity: A Review of Fuel Chain Emissions Based on Updated EPA National Inventory Data*. April 19, 2011. http://www.cleanskies.org/wp-content/uploads/2011/06/staple_swisher.pdf
[50] National Petroleum Council. *Prudent Development – Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*. Final Report Approved September 15, 2011. http://downloadcenter.connectlive.com/events/npc091511/Carbon-091511.pdf

Policies to Advance the Business Case for NGCC with CCS

One of the additional challenges associated with CCS on natural gas is reflected in many of the economic assumptions that go into modeling CCS on NGCC. While most of the economic scenarios use baseload capacity factors (those in Figure 3 assume capacity factors associated with baseload operation (>75 percent). In 2009, the average capacity factor of NGCC plants in the U.S. was only 42.2 percent.[51] While an important research topic is looking at the potential to optimize capture technologies for load-following or cycling natural gas power plants, opportunities for early, cost effective deployment will be on NGCC units that have high capacity factors.

Using EIA data, MJB&A estimates that only six natural gas fired power plants in the U.S. had capacity factors of more than 70 percent in 2010 (those six power plants had a total of 19 combined cycle units on site). Only one of those power plants had a capacity factor greater than 75 percent. Only 15 power plants and 55 units had a capacity factor of at least 65 percent (see Appendix C for a list). The 15 natural gas-fired power plants with capacity factors of more than 65 percent were located in seven states: California, Connecticut, Florida, Louisiana, New York, Oklahoma, Oregon, and Texas. California and Texas combined for almost half the total, four in California (with 14 units) and three in Texas (with 13 units). Figure 8 shows the number of plants with more than 250 MW of installed NGCC capacity associated with various ranges of estimated utilization in 2010.

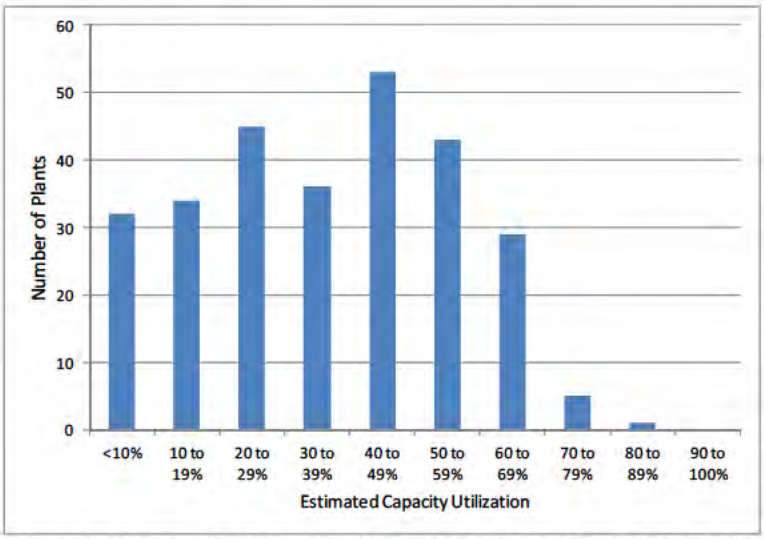

Figure 8. Estimated Utilization of Natural Gas Combined Cycle Capacity at Plants with Greater than 250 MW of Combined Cycle Capacity (MJB&A using EIA Form 860 and 923 data)

[51] U.S. Energy Information Agency (EIA). "Average Capacity Factors by Energy Source", *Electric Power Annual with data for 2009*. November 23, 2010 (April 2011 Update). http://www.eia.gov/cneaf/electricity/epa/epat5p2.html

Policies to Advance the Business Case for NGCC with CCS

Moving forward, an important research area for CCS on NGCC will be finding ways to optimize capture for conditions where the power plant has a low utilization and cycles on and off based on demand.

Appendix A: Summary of Recent Studies of NGCC-CCS Economics

Parameter	Units	Alstom (2015)	MIT Future of Natural Gas	EIA AEO	EPRI	NETL Baseline Rev 1	US Task Force on CCS	NETL Baseline Rev 2	Global CCS Institute (FOAK)
Study year	Year	2011	2010	2011	2009	2007	2010	2010	2011
Cost year	Year	2011	2005	2009	2007	2007	2009	2007	2010
Natural gas price	$/MMBtu				7.00	6.75		6.55	
Capacity factor	%			87%	80%	85%		85%	
Net plant efficiency w/o capture, HHV	%			53.1%	46.7%	50.8%		50.2%	
Net plant efficiency w/capture, HHV	%			45.4%	39.7%	43.7%		42.8%	
Natural Gas Price	$/Mbtu				7	6.75		6.55	
NGCC w/o CCS COE	$/MWh	58	56	63	66	68	77	75	88
NGCC w/CCS COE	$/MWh	88	85	89	91	97	121	109	115
Added COE for CCS	$/MWh	31	29	26	25	29	44	34	27
Cost of CO_2 Avoided	$/tonne CO_2	111			74	92	115	106	107

Sources

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Global CCS Institute: Schlumberger and WorleyParsons. *Economic Assessment of Carbon Capture and Storage Technologies: 2011 Update*, Global CCS Institute. March 8, 2011. http://cdn.globalccsinstitute.com/sites/default/files/publications/12786/economic-assessment-carbon-capture-and-storage-technologies-2011-update.pdf

Appendix B: Summary of S. 699

On March 31, 2011, Senator Jeff Bingaman (D-NM) introduced S. 699, the Department of Energy Carbon Capture and Sequestration Program Amendments Act of 2011. The bill has six cosponsors: Senators John Barrasso (R-WY), John Hoeven (R-ND), Lisa Murkowski (R-AK), John Rockefeller (D-WV), Jon Tester (D-MT), and Mark Udall (D-CO). S. 699 was reported out of the Senate Committee on Energy and Natural Resources in July 2011 but is not currently scheduled to be considered by the full Senate.

S. 699 would amend the Energy Policy Act of 2005 to create a large-scale carbon storage program. As a part of the program, the Secretary of Energy would be authorized to provide financial and technical assistance to up to ten large-scale demonstration projects, where large-scale is defined as a project that results in the injection of over 1 million tons of CO_2 annually into geologic formations. However, the bill does not provide funding for the program.

To encourage the development of projects, the bill authorizes the Department of Energy to provide projects with liability projection and federal indemnification up to $10 billion. The bill includes post-injection closure and monitoring requirements that extend to ten year after the CO2 plume has stabilized following the end of injection activities. After fulfilling the requirements, the bill would allow participating owners to transfer long-term monitoring and responsibility to the Department of Energy.

Appendix C. Natural Gas-Fired Power Plants with Capacity Factors Greater than 65 % in 2010, By State

Plant Name	State	Combined Cycle Capacity (MW)	No. of Units	Estimated Utilization of Total CC Capacity At Location	Classification
Cosumnes	CA	530	3	74%	Regulated Utility
Pastoria Energy Facility LLC	CA	779	5	73%	IPP
Sunrise Power LLC	CA	605	3	68%	IPP
Palomar Energy	CA	559	3	67%	Regulated Utility
Milford Power Project	CT	578	2	71%	IPP
Lansing Smith	FL	620	3	69%	Regulated Utility
Manatee	FL	1,225	5	68%	Regulated Utility
Louisiana 1	LA	406	5	67%	IPP
Astoria Energy	NY	520	3	72%	IPP
Brooklyn Navy Yard Cogeneration	NY	322	4	68%	IPP
McClain Energy Facility	OK	469	3	85%	Regulated Utility
Klamath Cogeneration Plant	OR	502	3	68%	IPP
Gregory Power Facility	TX	432	3	72%	IPP
Deer Park Energy Center	TX	996	5	66%	IPP
Channelview Cogeneration Plant	TX	918	5	65%	IPP

Vice President of Environmental Health and Safety, Calpine Corporation

DONALD NEAL joined Calpine Corporation in 2000 and has served as Vice President of Environmental Health and Safety since 2006. He is responsible for all aspects of Calpine's EHS programs including policy and standards, compliance, regulatory affairs, SEC and Sarbanes Oxley reporting, and strategic planning. Mr. Neal has over 28 years of experience with EHS issues and was recently appointed to EPA's Clean Air Act Advisory Committee. Prior to joining Calpine, he worked at Earth Tech, where he assisted power plant developers with licensing and evaluating existing assets for potential acquisition. He also was a Senior Consultant with Arthur D. Little, Inc., where he assisted industrial clients with developing and implementing EHS management systems. Mr. Neal has a Master of Science in Biology from the University of Massachusetts.

CALPINE

A Generation Ahead today

CCS – An Electric Generator Perspective

Natural Gas CCS Forum
November 4, 2011

Donald Neal, VP EHS

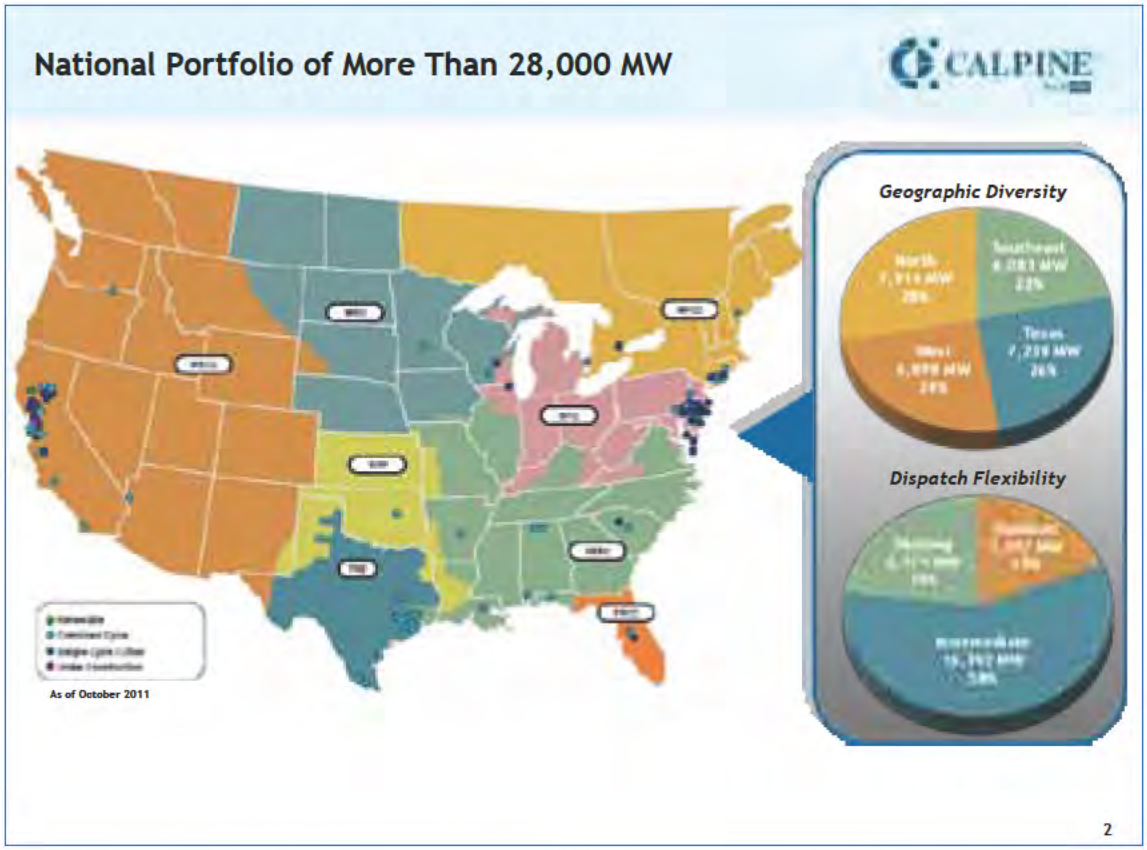
Agenda

CALPINE

- Calpine Corporation description
- Russell City Energy Center GHG Permit and BACT
- Recent developments in GHG BACT
- Calpine's view on CCS

1

2:45–4:15 PM Session


National Portfolio of More Than 28,000 MW
CALPINE
Geographic Diversity
Dispatch Flexibility
As of October 2011
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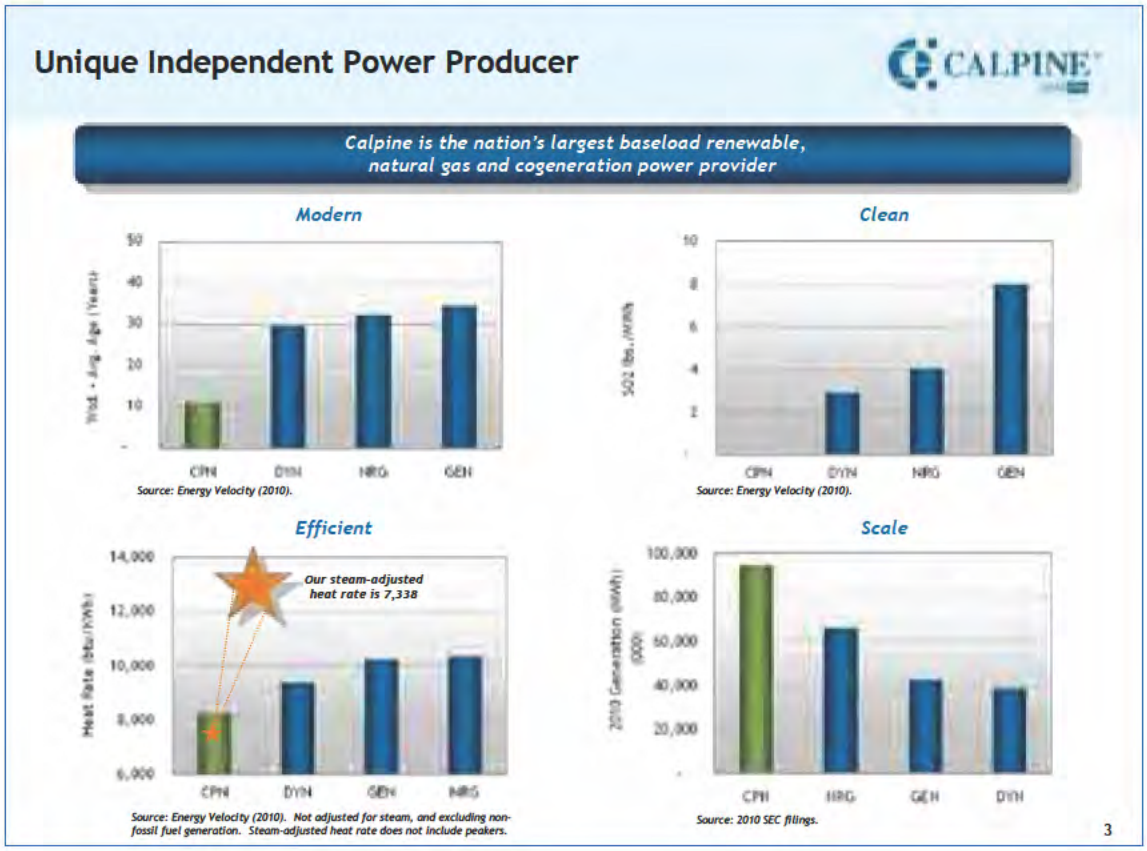
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CPN
DYN
NRG
GEN
Source: Energy Velocity (2010).
Clean
SO2 lbs./MWh
Source: Energy Velocity (2010).
Efficient
Heat Rate (btu/kWh)
Our steam-adjusted heat rate is 7,338
Source: Energy Velocity (2010). Not adjusted for steam, and excluding non-fossil fuel generation. Steam-adjusted heat rate does not include peakers.
Scale
2013 Generation (MWh) (000)
Source: 2010 SEC filings.
3

Russell City Energy Center

- First power plant to have federally-enforceable GHG limits through permit issued by Bay Area Air Quality Management District (BAAQMD)
- 612 megawatt natural gas fired combined cycle power plant in Hayward, CA.
- Performed 5-Step BACT analysis before EPA Guidance was issued
  - Step 1: Identify control technologies
    - Combustion controls identified thermal efficiency
    - Add on controls identified CCS
  - Step 2: Eliminate technically infeasible options
    - CCS not commercially available
    - DOE expects commercial deployment in 2025 (73 FR 44370)
    - Appropriate sequestration sites in bay area not demonstrated
- Conclusion that high-efficiency power generation technology is the only available and feasible control technology
- BAAQMD determined that BACT limit in permit would have both mass and efficiency limits
  - Permit issued February 2010
  - EAB denied all appeals November 2010

4

Russell City Energy Center BACT Limits

- Mass emission limits based on permitted heat input

Averaging Period	Heat Input Limit (MMBtu)	Greenhouse Gas Emissions Limits (metric tons CO_2E)			
		CO_2	CH_4	N_2O	CO_2E
1-Hour	4,477.2	242	0.08	0.14	242
24-Hour	107,452.0	5,797	2.03	3.33	5,802
Annual	35,708,858.0	1,926,399	675	1,107.48	1,928,182

- Efficiency limits based on baseload heat rate plus degradation factors

Condition	Heat Rate (Btu/kwh)
Net Design Base (new and clean)	6,852
Installed Design Base (3.3% design margin)	7,080
Degraded Base (degradation between major overhauls and compliance margin)	7,730

5

2:45–4:15 PM Session

Recent Developments in GHG BACT – EPA GHG Guidance

- November 10, 2010 - EPA issued PSD and Title V Permitting Guidance for GHGs
- Step 1 – Identify all available control options
  - CCS specifically listed as "available" for fossil fuel-fired power plants
- Step 2 – Eliminate technically infeasible options
  - Lack of a commercial guarantee does not render CCS technically infeasible
  - CCS has three main components any of which may be technically infeasible:
    - Capture and compression
    - Transport
    - Storage
  - EPA concludes at this time CCS is likely to be deemed technically infeasible
    - Permitting record does not show CCS is "demonstrated in practice" or "available and applicable"
- Significant hurdles
  - Contracts for off-site land
  - Funding
  - Availability of transportation infrastructure
  - Long term storage site

6

Recent GHG BACT Activity

- Calpine Deer Park expansion filed with EPA Region VI September 2011 rejected CCS in Step 2
  - Amine absorption not commercially available for gas fired power plants that have larger flow volumes and lower CO2 concentrations
  - Uncertainty regarding transportation arrangements (10-250 mile pipeline)
  - No proven sequestration site
- Draft GHG permit issued by EPA Region VI to Lower Colorado River Authority September 2011:
  - CCS not specified
  - Average net heat rate of 7720 Btu/kwh

7

View On CCS for Natural Gas

Parameter	Without CCS	With CCS	Diff. (%)
Net power output (MW)	528	461	-13
Net Efficiency (%)	56.6	48.4	-14
CO2 Emissions (kg/MWh)	370	55	-85
Capital Cost ($/kw)	960	1715	+79
Cost of CO2 Avoided ($/tCO2)	n/a	80	n/a

Note: Average of nine estimates using F-Class Gas Turbine. Does not include transportation and storage

Source: Finkenrath, Matthias, 2011, Cost and Performance of Carbon Dioxide Capture from Power Generation. International Energy Agency Working Paper. Paris, France.

- **$80 CO2 removal cost for CCGT compares to $55 removal cost for PC**
- **Calpine has no plans to install CCS even at a pilot scale**

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CALPINE

CALPINE

2:45–4:15 PM Session

Principal,
Kruger Environmental Strategies LLC

Former Director of the Climate Change Division,
USEPA

President's CCS Task Force

DINA KRUGER is the president of Kruger Environmental Strategies LLC, a firm that helps organizations more effectively respond to and engage in the development and implementation of environmental programs and regulations. Her clients include corporations, foundations and non-governmental organizations. Prior to founding KES, Dina spent 22 years at the US Environmental Protection Agency, serving as the director of the Climate Change Division from 2004 to 2011. At EPA, Dina managed development of EPA's GHG Reporting Program and the 2009 Endangerment Finding. She also led EPA's work on key energy technologies, including carbon capture and storage, unconventional natural gas, and bio-energy, as well as EPA's GHG partnership programs with the coal, natural gas, waste, metals, and fluorinated gas industries. She holds a bachelor's degree from the University of Washington, and a master's degree from the Energy and Resources Group at the University of California, Berkeley.

The CCS Regulatory Landscape:
Progress & A Look Ahead

Dina Kruger
Kruger Environmental Strategies LLC
November 4, 2011

Overview

- Several EPA regulations underway or completed
  - UIC rule under the Safe Drinking Water Act
  - Proposed Exemption for CO_2 Injection under RCRA Subtitle C
  - GHG Reporting Program requirements
  - Permitting & BACT program
  - Utility GHG NSPS
- Two critical issues still to be addressed
  - Liability framework for CCS projects
  - Regulatory framework for shale gas production

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2:45–4:15 PM Session

EPA Activities

UIC & GHG Reporting Rules

- Underground Injection Control program
  - Final regulation establishing "Class VI" wells for CO_2 storage promulgated in December 2010
  - EPA is the permitting authority until states apply for primacy
  - Limited number of permits so far
- GHG Reporting Program
  - Final regulation promulgated in December 2010.
  - Requires development of a monitoring plan for GHG for Class VI wells, with opt in for other well classes
  - Unclear how many projects will report in the near term, given pervasive climate policy uncertainty.

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RCRA Subtitle C

- Conditional exemption for CO_2 Injection in UIC Class VI wells from RCRA hazardous waste requirements
  - Proposed in August 2011
  - Comment Period closed October 7, 2011
- Main thrust of comments
  - Industry wants blanket exemption from RCRA
  - Environmental groups want more data regarding injectate properties; concerned about potential contaminants
- Final rule scheduled for February 2013

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PSD Permitting Guidance

- EPA BACT Guidance (11/2010) identifies two widely applicable control options for large CO_2 emitters: energy efficiency and CCS
- EPA encourages all permitting authorities to consider energy efficiency options
- EPA states that it CCS to be considered, but may not be required:
  - "EPA classifies CCS as an add-on pollution control technology that is "available" for large CO_2-emitting facilities...For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for such sources... CCS is an option that merits initial consideration, and, if the permitting authority eliminates this option at some later point in the top-down BACT process, the grounds for doing so should be reflected in the record with an appropriate level of detail."
- Permitting actions to date have relied on efficiency and not required CCS.

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Utility GHG NSPS

- Not yet proposed (new schedule to be *negotiated* by Nov)
- Expected to focus on new coal-fired power plants
- Issue 1: How Stringent?
  - As with permitting, main technological options are energy efficiency and CCS, with a single standard or fuel-specific standards.
    - Efficiency is inexpensive, but does not deliver significant reductions
    - CCS delivers big reductions, but has not been deployed at this scale and is much more expensive
- Issue 2: How Flexible?
  - While flexibilities appear legal under NSPS program, trading appears unlikely due to Congressional opposition
- Issue 3: How Broad?
  - EPA will regulate new sources and could provide guidance to states on the regulation of existing sources
  - Effectiveness of EPA's action depends on how much new coal capacity will be built and the stringency of the standards
  - Regulation of existing sources could take 3+ years, and states can issue weaker standards

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Looking Forward: Two Outstanding Issues

CCS Liability

- The President's CCS Task Force reviewed a variety of approaches to address long-term (post-closure) liability, and recommended further consideration of 4 of them:
  - Reliance on the existing framework for long-term liability and stewardship;
  - Adoption of substantive or procedural limitations on claims;
  - Creation of an industry-financed trust fund to support long-term stewardship activities and compensate for losses or damages that occur after site closure;
  - Transfer of liability to the Federal government after site closure (with certain contingencies)
- Panel concluded that "open-ended Federal indemnification should not be used to address long-term liabilities associated with CO_2 storage"

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Work needs to continue

- Stakeholders have different perspectives on long-term liability:
  - Industry has stated that long-term liabilities are a key barrier to commercial deployment of CCS
  - Some insurers have said that they cannot currently write policies to cover post-closure risks because they cannot estimate the cost of such policies
  - Environmental groups are concerned that relieving businesses of long-term risks could create a moral hazard and some are unconvinced that the issues surrounding CCS are uniquely challenging
- A stakeholder process that includes all perspectives should be established to develop consensus recommendations

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Broader Regulatory Framework for Shale Gas

- Today's discussion is founded on the expectation that development of shale gas resources will drive significant growth in use of natural gas
- This potential growth is threatened by public concern over environmental issues associated with production and use:
  - Infrastructure impacts
  - Water use and disposal
  - Air quality impacts
  - Greenhouse gas impacts
- Whether real or perceived, these concerns must be taken seriously.

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Public Acceptance is Critical to the Development of New Gas Reserves

- Building confidence in shale gas depends on:
  1. Information and data on what is being done during production
  2. Monitoring data on environmental impacts
  3. A regulatory framework that avoids environmental problems to the extent possible and ensures proper clean-up when problems do arise
- This framework needs to be established quickly, before positions harden, and in collaboration with industry, NGOs, and regulators (state and Federal)
- Public opposition to shale gas development could signal future problems for widespread CO_2 injection

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Conclusion

- In the absence of national climate legislation, increased use of natural gas use can be an important near-term GHG mitigation strategy
- During the current policy vacuum, efforts to move key technologies - like CCS -- toward commercial deployment must be maintained
- And particular attention should be paid to public concerns regarding both shale gas development and CCS

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Thanks!

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