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Can CCS Bring Gas from Bridge to a Destination?

A literature review

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Contents

Strategic Value ... 3
ACSF held a public forum on CCS for natural gas ... 4
The Forum ... 4
Background ... 4
Converging factors ... 5
I. Why CCS for gas? ... 9
- *Regional carbon intensity* ... 13
- *Conclusions* ... 16
- *Key Findings* ... 17

II. CCS Status ... 17
- *CCS Technologies* ... 18
- *Postcombustion capture* ... 20
- *Demonstrations* ... 25
- *Costs* ... 26
- *Relative emissions* ... 27
- *California Carbon Capture and Storage Review Panel* ... 28
- *CO2 Storage* ... 29
- *Large scale storage projects* ... 30
- *EPA and DoE tracking of storage projects* ... 31
- *EOR* ... 32
- *Monitoring, verification, and accounting* ... 33
- *Regulatory and policy challenges* ... 33
- *S. 699* ... 34

End Notes ... 35

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 .

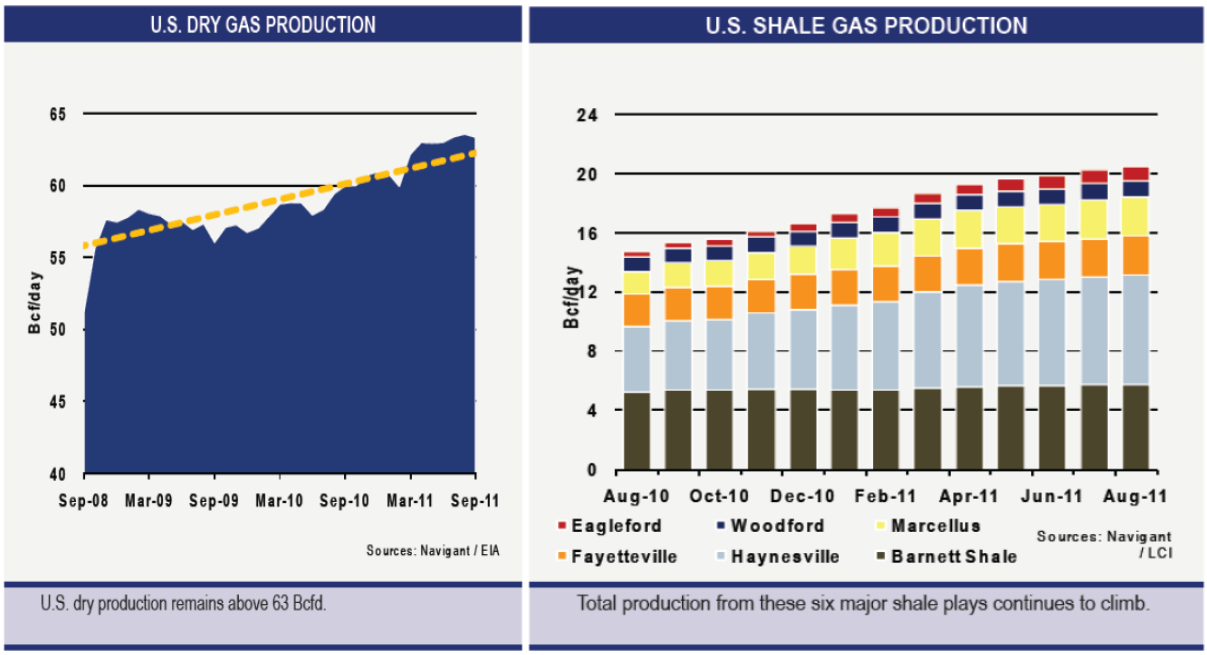
Background As more mature and unscrubbed coal plants face continued economic and regulatory pressures, there is an opportunity to significantly reduce emissions from power plants by increasing the consumption of gas in the generation fleet. Growth in gas demand in the power sector also is expected as 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.



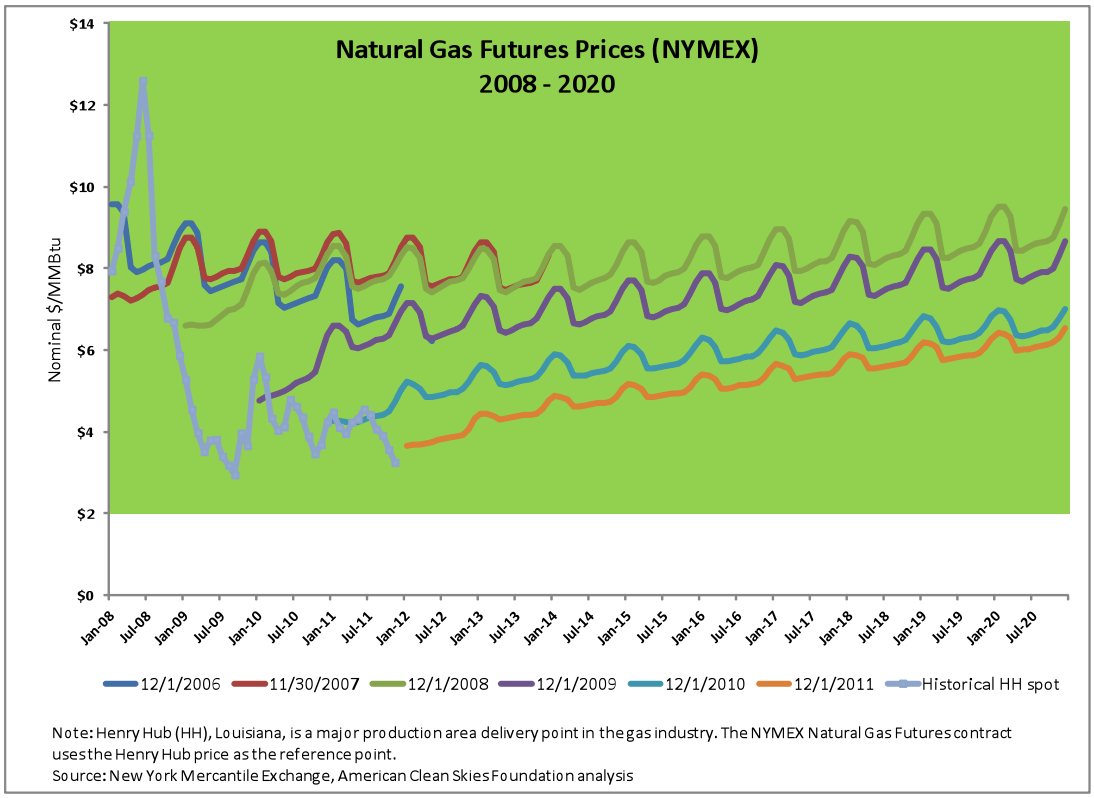
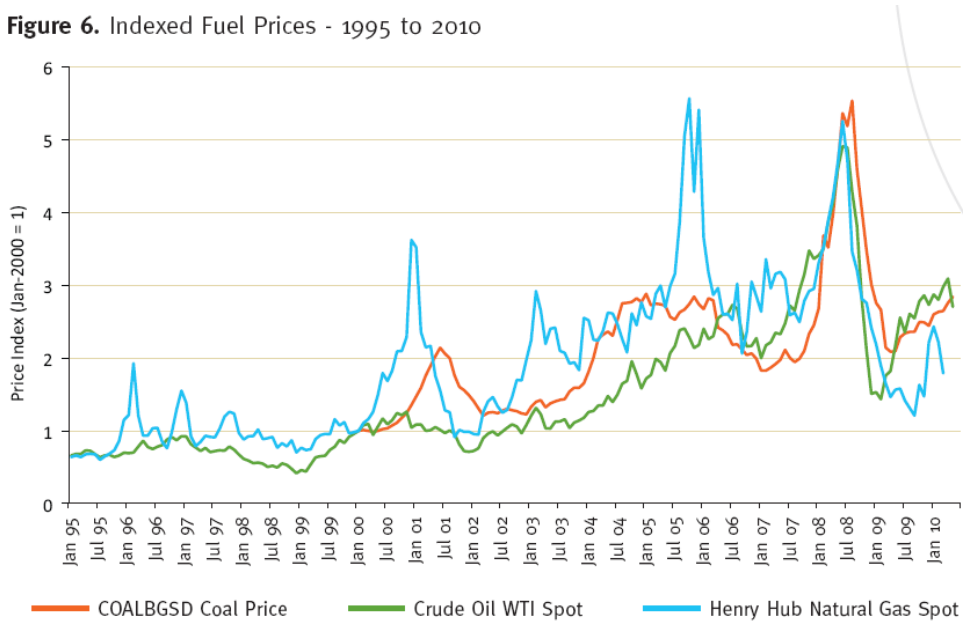


Figure 6 illustrates how an energy price index for coal, gas and oil has varied since 1995 (1)—by Jan 2010, gas price has diverged sharply from that of coal and this trend continues, especially as more Appalachian coal is exported.

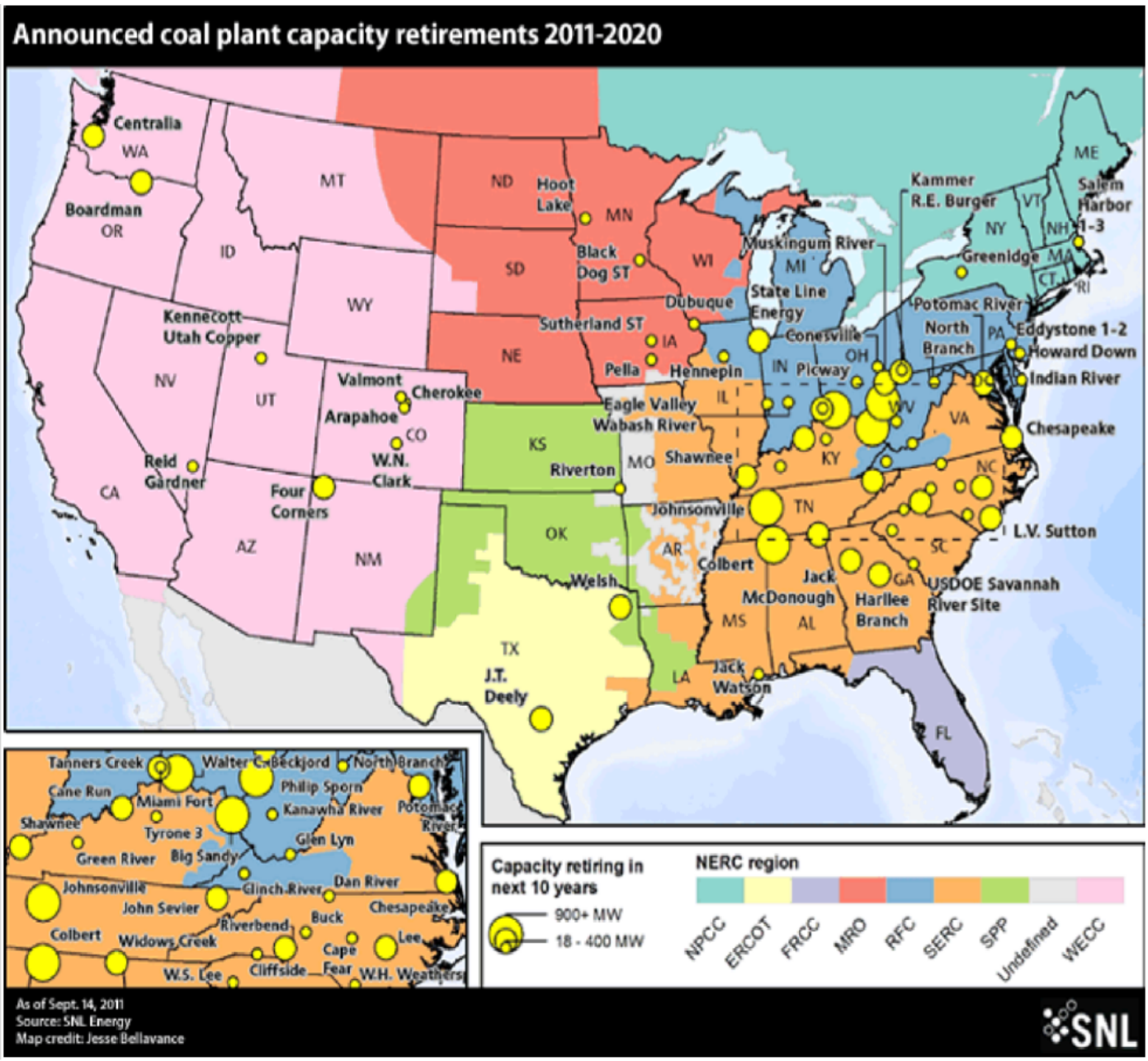


Source: ICF International analysis of U.S. Energy Information Administration data.

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.

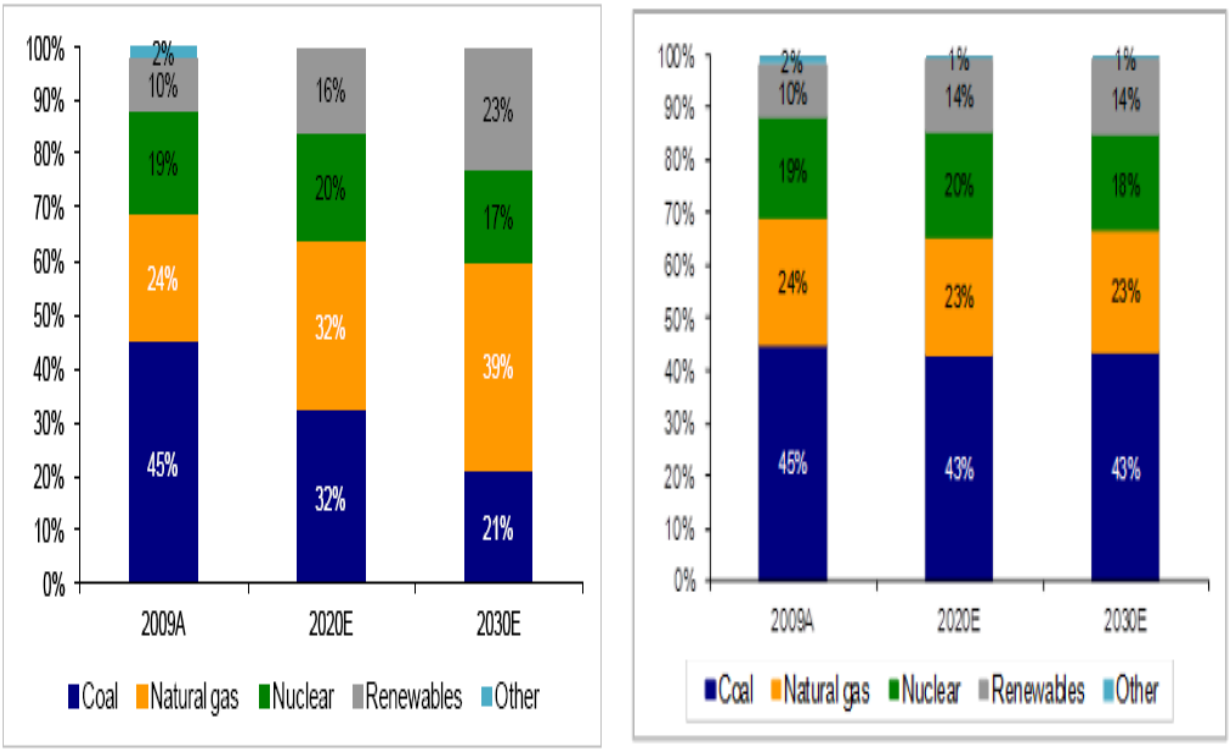


Driven by market forces, a growing fuel price gap between coal and gas, regulatory pressures from Clean Air Act enforcement actions, profitability concerns and grid reliability requirements, the closing of marginal coal plants creates an historical opportunity for building new NGCCs in the U.S. Deutsche 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*.

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

DBCCA Forecast

EIA Forecast



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?

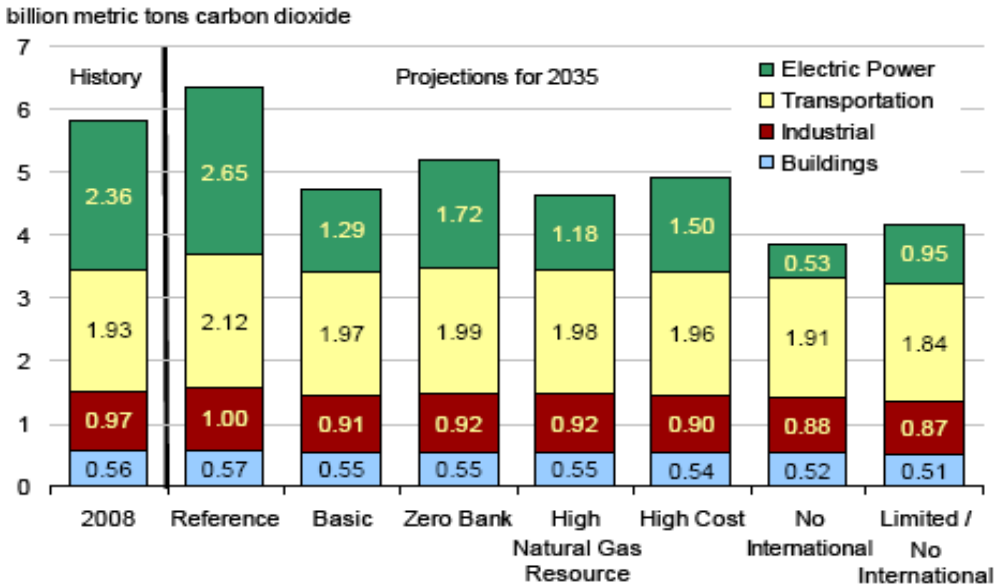
As the electricity grid evolves, when does uncaptured carbon from gas begin to become a challenge? It depends greatly on the development and stringency of Federal limits on greenhouse gases, and the expansion of regulation of greenhouse gases at the State or regional level.

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.

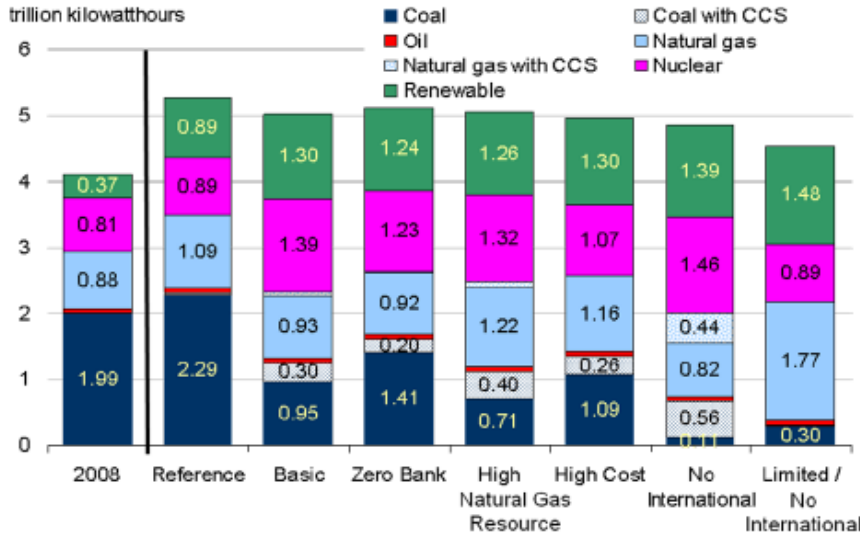
The most stringent domestic emissions scenario in the EIA study is the "No International" case (NI-no int'l. carbon offsets), which appears to have the most severe constraints on the Power sector. Figure 3 shows the energy-related CO2 in 2035 by sectors. The "High Natural Gas" (HNG) case assumes doubling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

Figure 3. Energy-related CO_2 emissions by emitting sector in APA cases, 2035



Source: National Energy Modeling System, runs KGL_REFERENCE.D062910A, KGL_BASIC.D062910A, KGL_HISHALE.D062910A, KGL_HICOST.D062910A, KGL_NOINT.D062910A, and KGL_LTDNOI.D062910A.

Figure 4. Generation by fuel in APA cases, 2035



Source: National Energy Modeling System, runs KGL_REFERENCE.D062910A, KGL_BASIC.D062910A, KGL_HISHALE.D062910A, KGL_HICOST.D062910A, KGL_NOINT.D062910A, and KGL_LTDNOI.D062910A.

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.

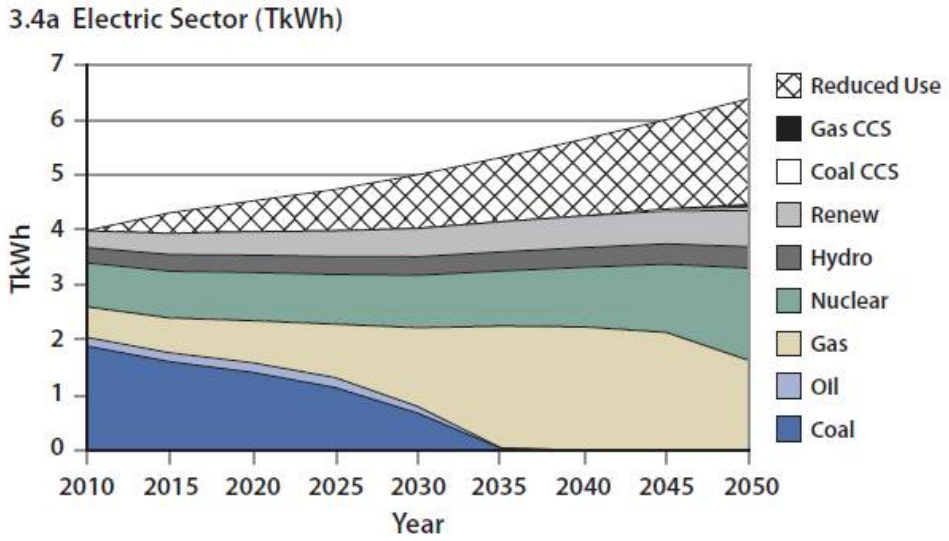
Fig. 4 details the Power sector fuel use. Here is how the US grid mix changes:

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:

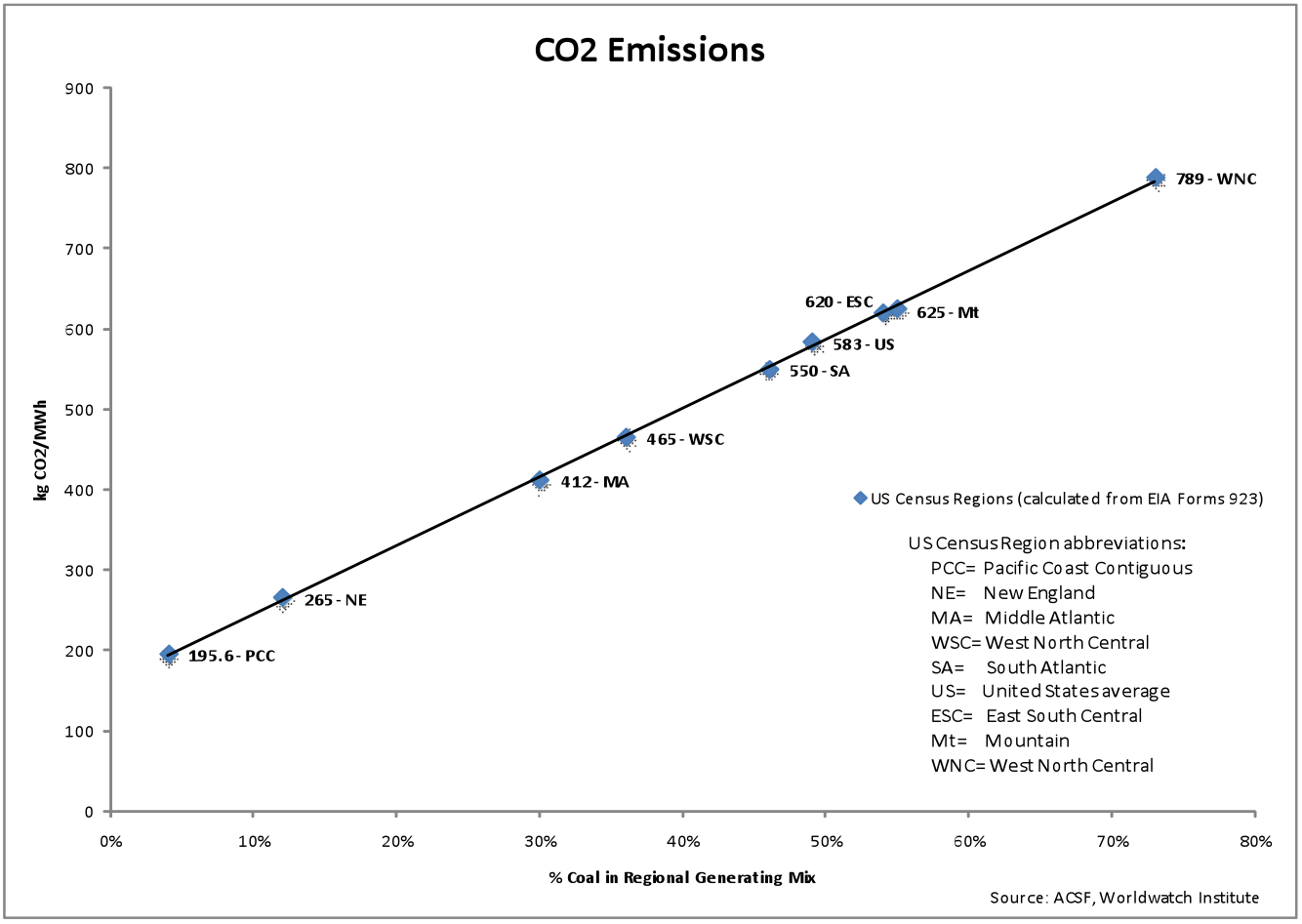
- CCS for gas starts to appear between 2016 and 2020 in the EIA scenario with the most severe CO_2 reduction, where by 2035 about 9% of electricity is generating using gas equipped with CCS, and
- Barely any CCS for gas appears by 2045-2050 in the MIT evaluation of a much milder policy—not put forward 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%	8%	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: EIA, 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 CO2, and starting in 2012, the cap-and-trade program will apply to industrial sources emitting more than 25,000 metric tonnes of CO2 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:

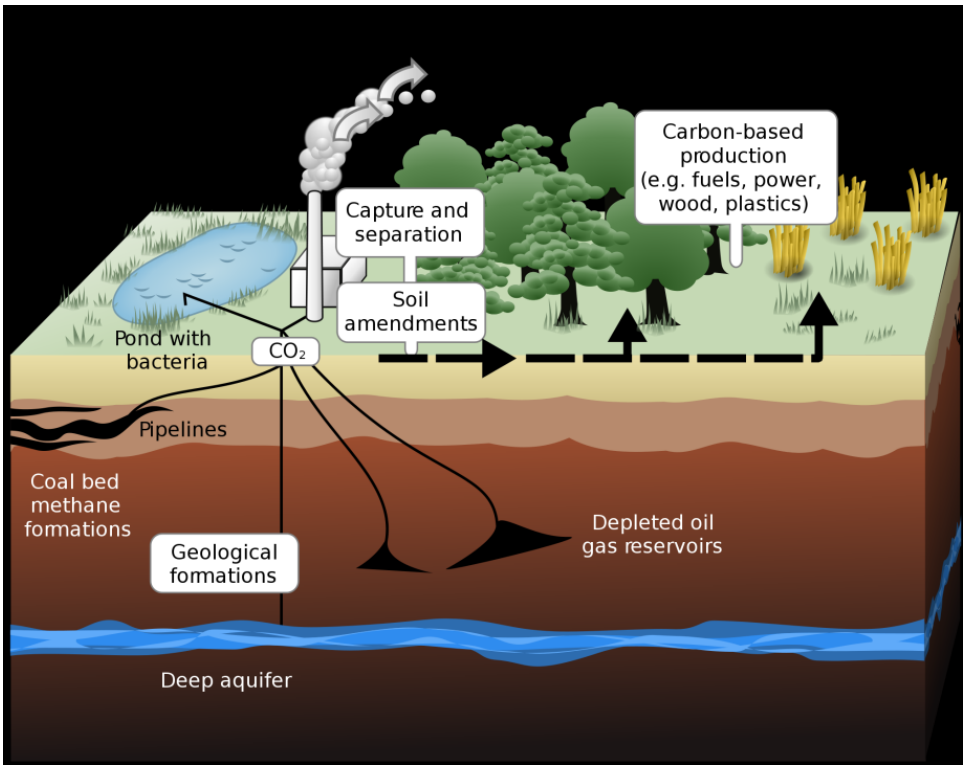
- The President's Interagency Task Force on Carbon Capture and Storage, composed of 14 Executive Departments and Federal Agencies (report in August 2010 (9)), and
- The California Carbon Capture and Storage Review (report in December 2010 (10)) overseen by the CA Energy Commission, Public Utility Commission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

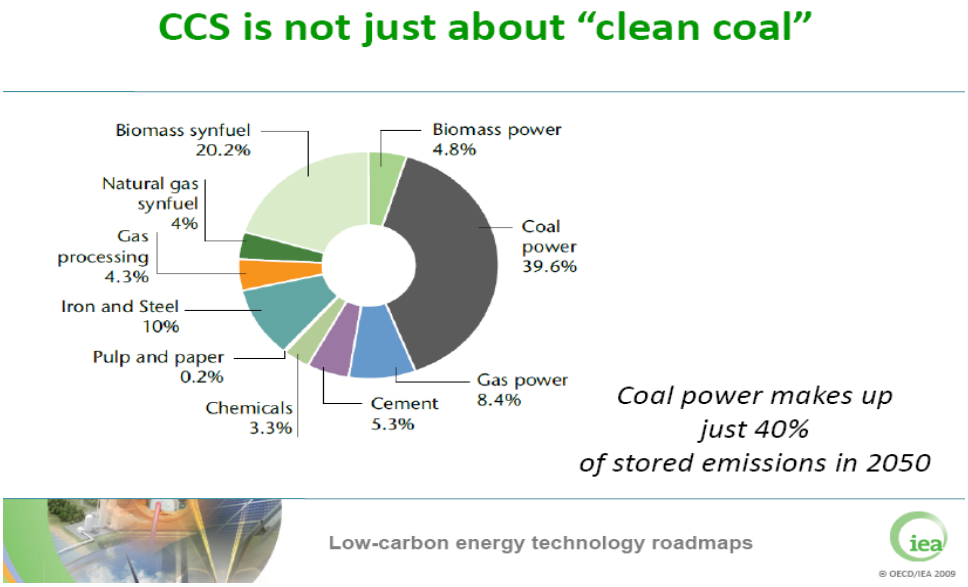
> "While there are no insurmountable technological, institutional, regulatory or other barriers that prevent CCS from playing a role in reducing GHG emissions, early CCS projects face economic challenges related to climate policy uncertainty, first-of-a-kind technology risks, and the current high cost 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.



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



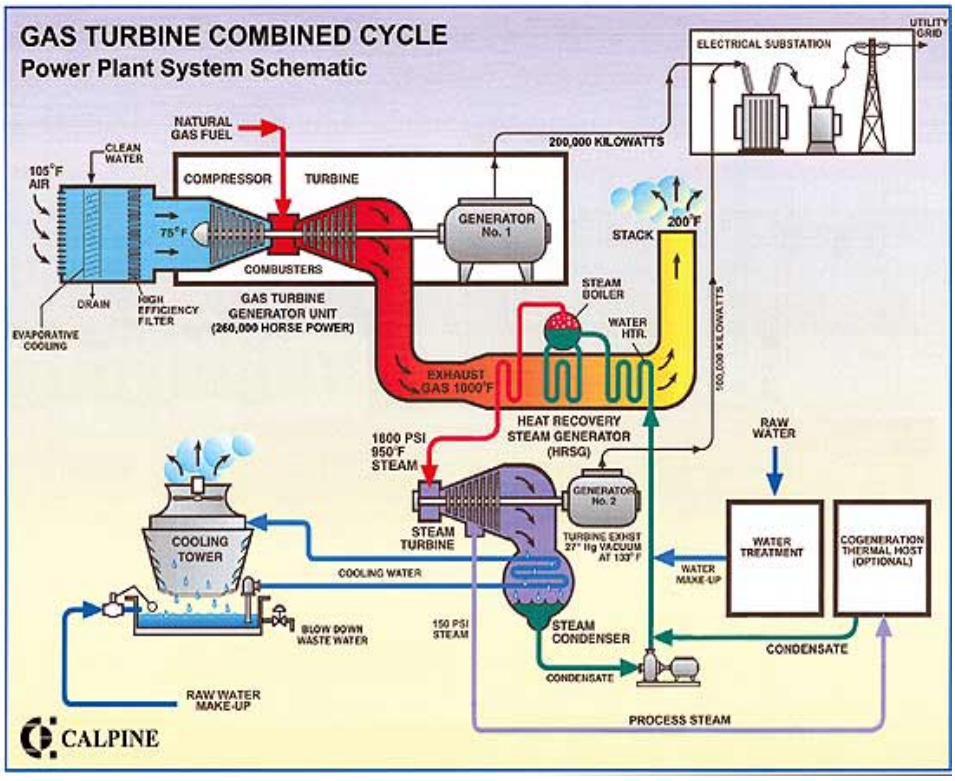
CO_2 can also be associated with production of natural gas, which could contain from none (most shale gas production has little associated CO_2) to nearly 78%, as is encountered in the LaBarge field in Wyoming, whose Shute Creek separation plant (ExxonMobil) yields some 3.6 Mt/yr, compared to a single 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.

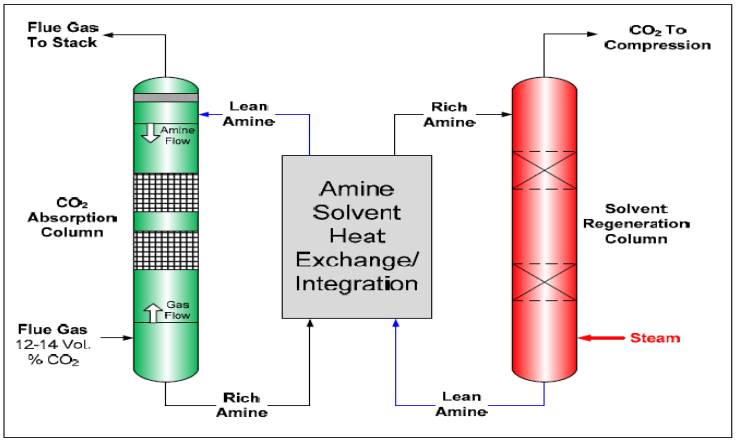


A 2009 review of commercially available CO2 capture technologies identified 17 facilities in current operation in the US (9)(11). They include four gas processing operations and a syngas production facility in which approximately 1 MT of CO2 are captured each year. The largest, Shute Creek in Wyoming (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



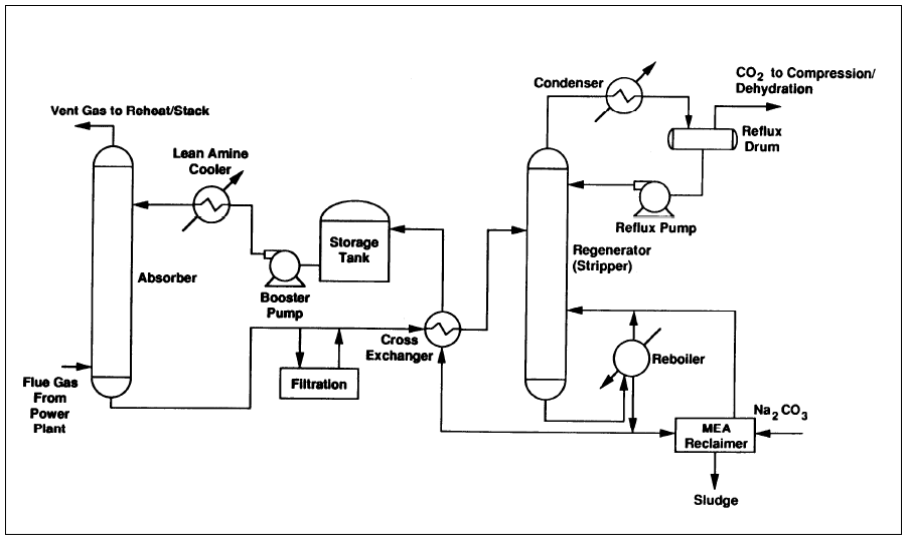


Figure 1. Process flow diagram for the amine separation process.

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).

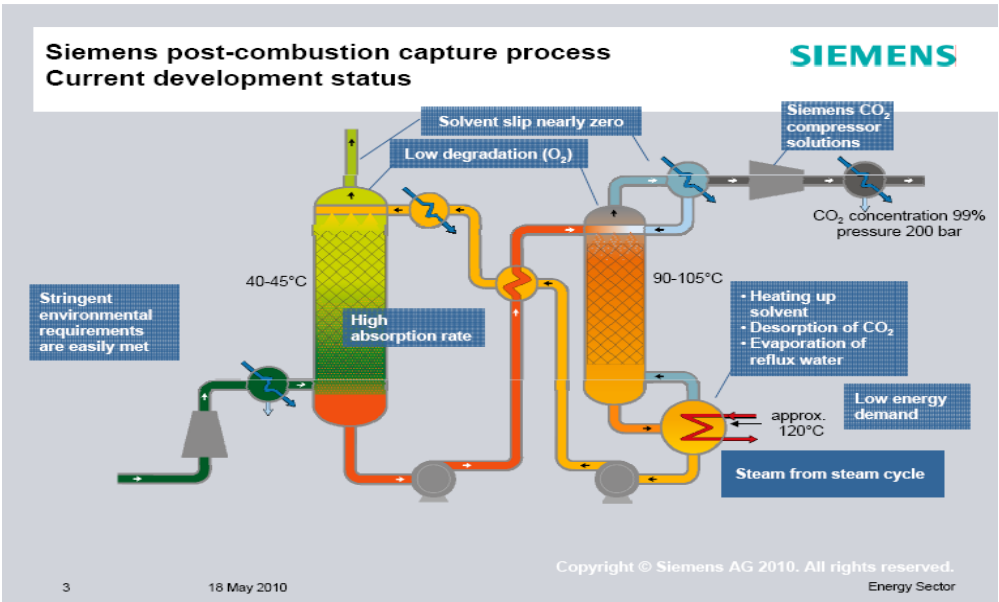


Table A-3. Key Technical Challenges for CO_2 Capture

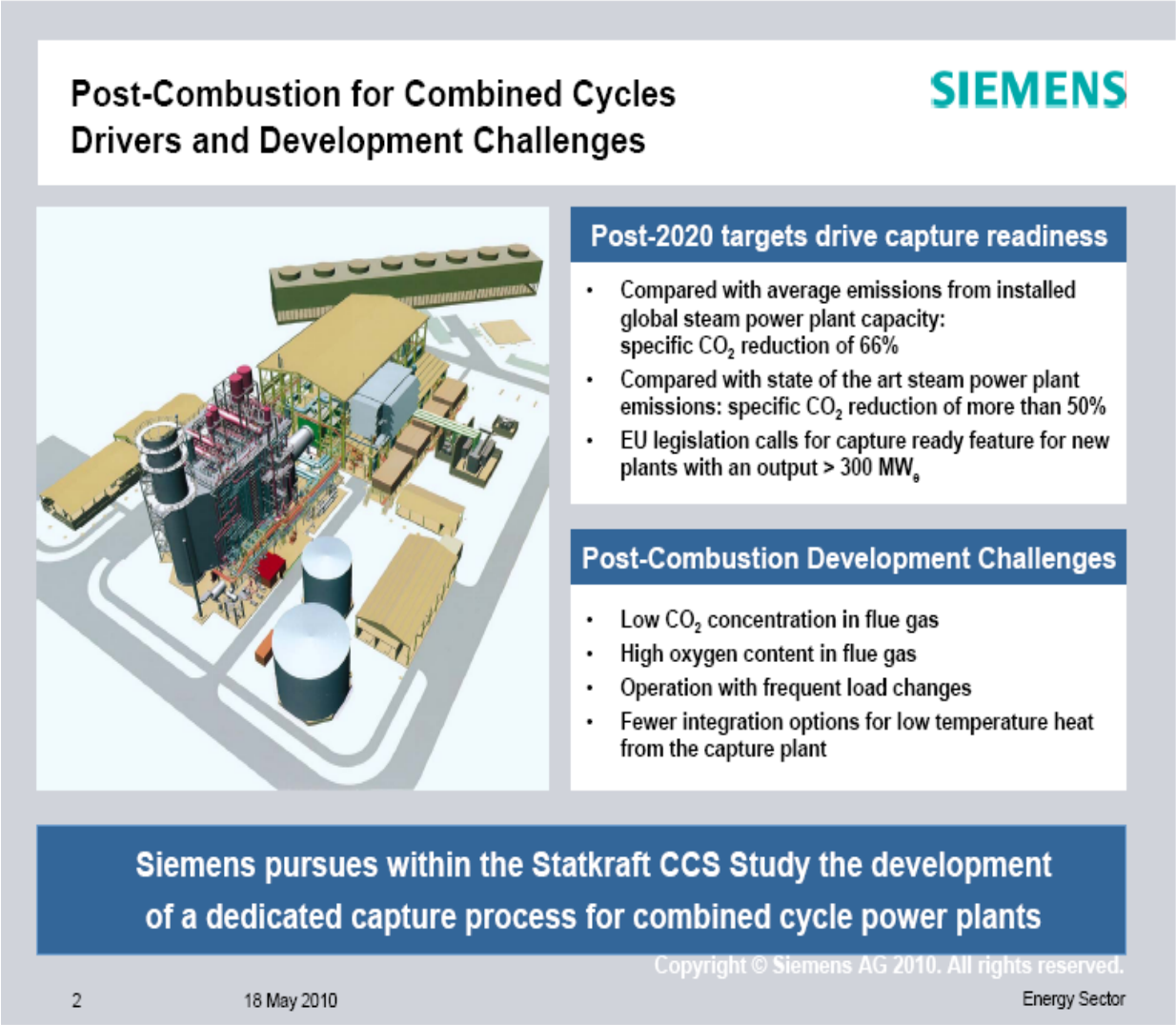
Parameter	Technical Challenge
Scale-Up	While industrial-scale CO_2 separation processes are now commercially available, they have not been deployed at the scale required for large power plant applications and consequently, their use could significantly increase electricity production costs.
Cost-Effectiveness	Recent studies conducted by NETL show that current technologies are expensive and energy-intensive, which seriously degrade the overall efficiency of both new and existing coal-fired power plants. For example, installing the current state-of-the-art post-combustion CO_2 capture technology – chemical absorption with an aqueous monoethanolamine (MEA) solution – is estimated to increase the levelized COE by about 75 to 80 percent.
Auxiliary Power	A significant amount of auxiliary power is required to operate currently available CO_2 capture technologies. The auxiliary power decreases the net electrical generation of the power plant.
Energy Efficiency	The large quantity of energy required to regenerate the solvent in commercially available CO_2 capture technologies (~1,550 to 3,000 British thermal units [Btu] per pound of CO_2 removed) would significantly reduce the total power plant output.
Energy Integration	The energy required to regenerate the solvent in commercially available CO_2 capture technologies would be provided by steam extraction from the power plant. This activity requires careful integration of the power plant steam cycle to the CO_2 capture technology.
Flue Gas Contaminants	Constituents in the flue gas, particularly sulfur, can contaminate CO_2 capture technologies, leading to increased operational expenses.
Water Use	A significant amount of water use is required for CO_2 capture and compression cooling.
CO_2 Compression	To enable storage, significant power is required to compress the captured CO_2 to typical pipeline levels (1,500 to 2,200 psia depending on storage scheme and location). Reducing this power requirement is essential to improving overall plant efficiency and facilitating CO_2 storage at both existing and future power plants.
Oxygen Supply	An oxy-combustion power plant requires a supply of high-purity oxygen. Currently available technology – cryogenic air separation unit (ASU) – is not considered to be cost effective.

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

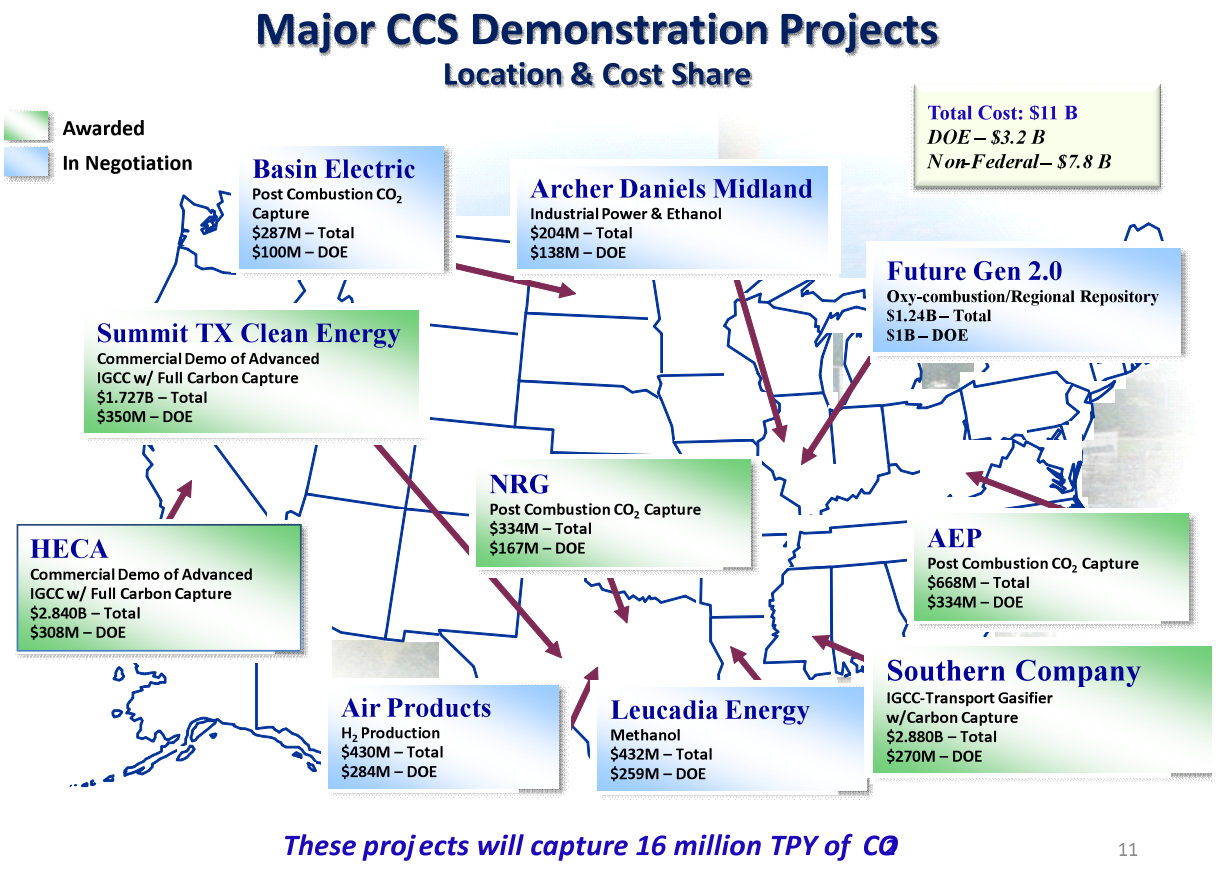
be supporting large scale commercial demonstrations of PCC ((17)—a now outdated review, as funding has changed).



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.

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.

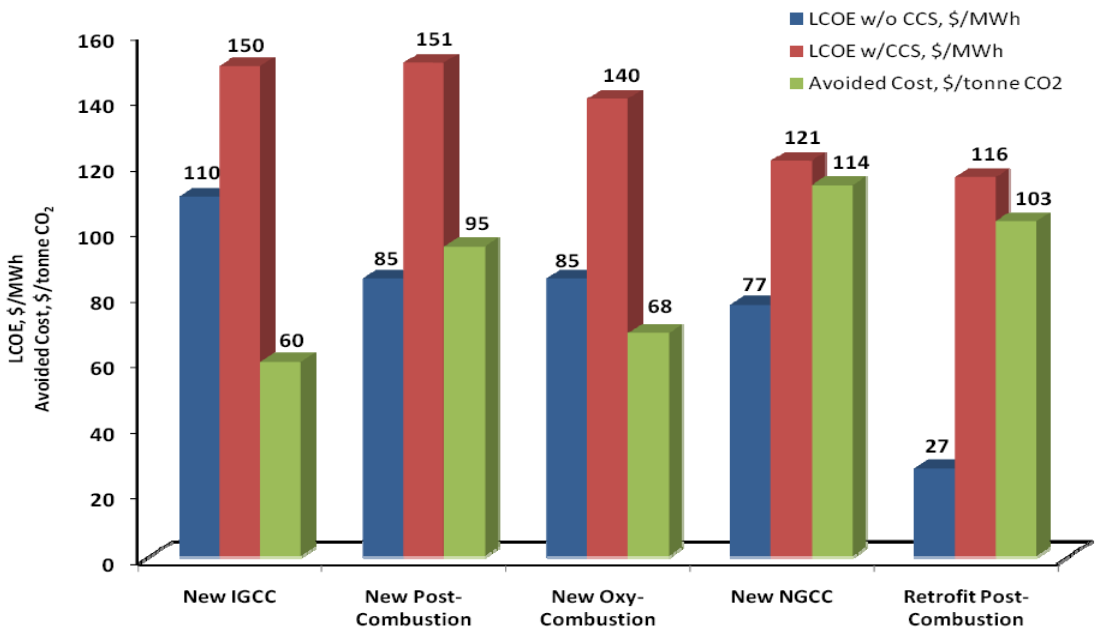


Costs Figure A-9 (9) compares the levelized cost of electricity (LCOE, (18)) from a variety of simulated 550 MWe plants with and without CCS. New NGCC plants would be somewhat cheaper than any of the coal plant options, and NGCC retrofit would likely be cheaper than retrofits for coal plants.

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



Source: (DOE, 2010a; DOE, 2010b)

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

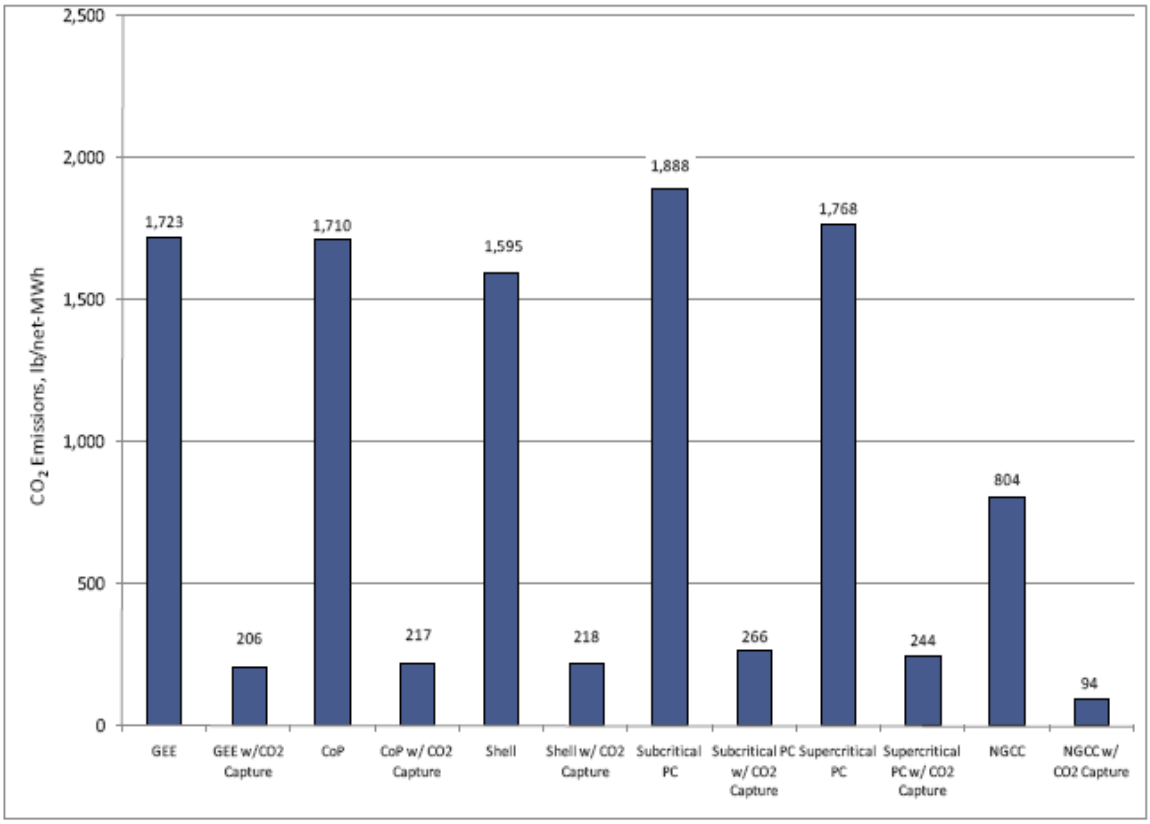
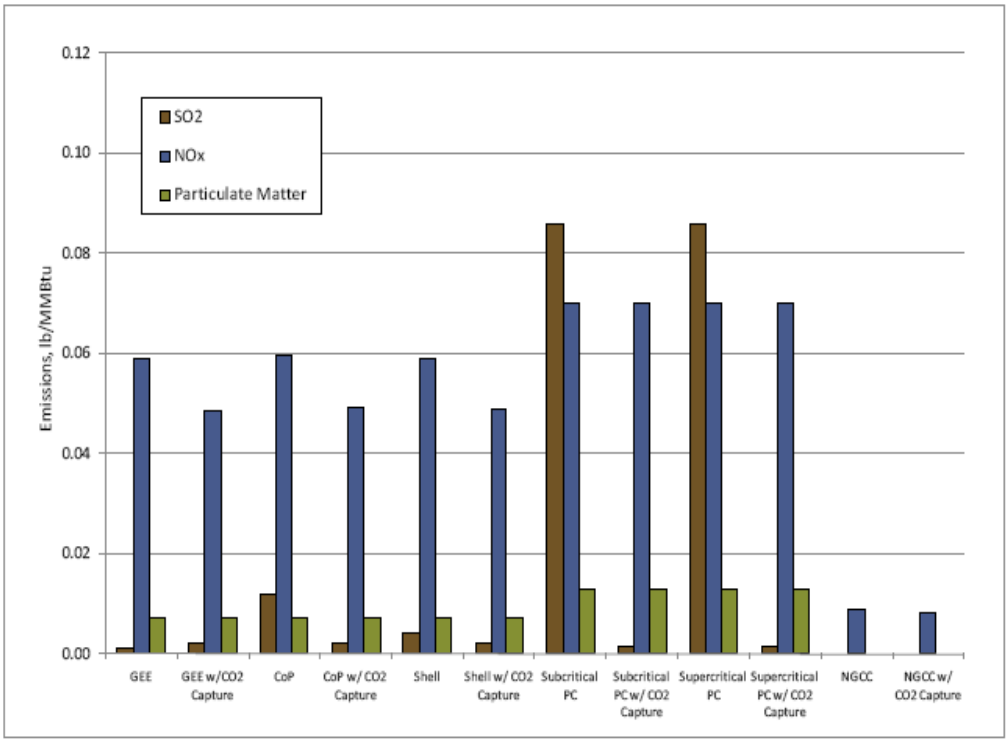


Exhibit ES-15 SO_2, NOx, and Particulate Emission Rates



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.

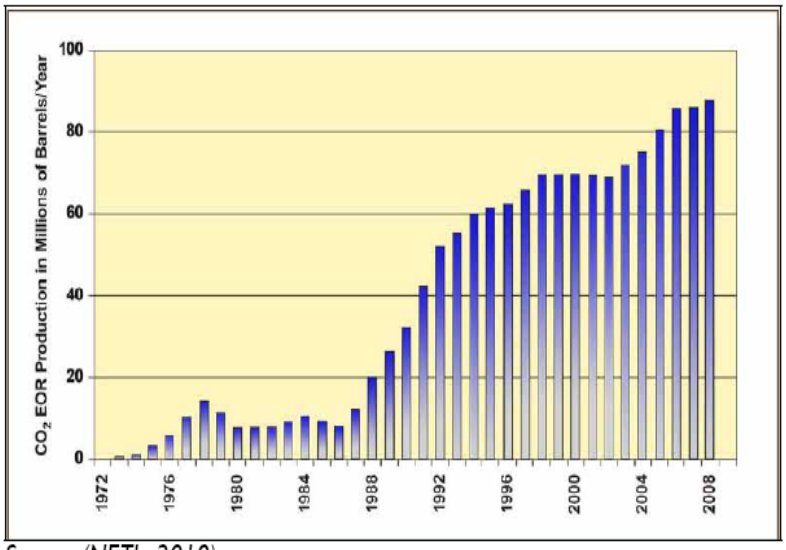
Other pathways to identifying geologic storage opportunities are noted in: "*Impact of the Marcellus Shale Gas Play on Current and Future CCS Activities"* NETL (August 2010)(23).

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)

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

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

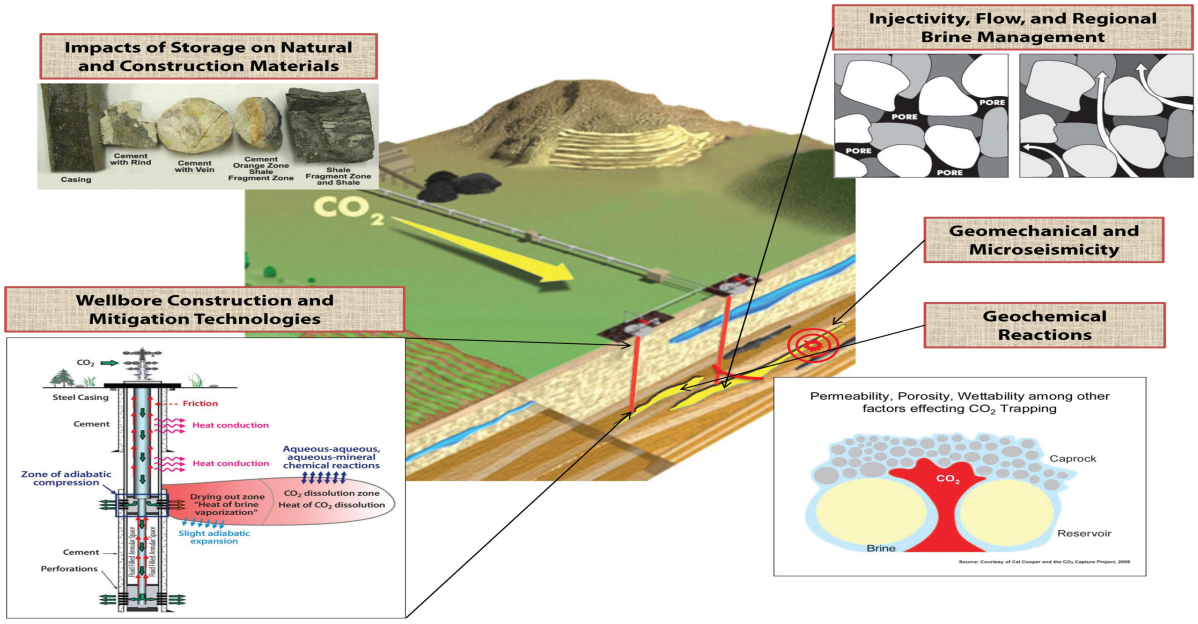
21) "Legal and Regulatory Inventory for Carbon Capture and Storage & Analogues", Midwestern Governor's Association (March 2009);

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