

CLIMATE CHANGE BUSINESS JOURNAL®

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Fossil Fuels Forced to Make Long-Term Plans in an Uncertain Policy Present

The future of fossil fuels will be impacted by a complex mixture of prices, supply, technology, policy, investment and global geopolitical dynamics. These factors in turn will be impacted by security, economic, climate change and other imperatives. In this environment, energy and power planners, and their service and technology suppliers, are often forced to make long-term decisions. In this edition, CCBJ turns its attention to future energy scenarios and market drivers, with a specific focus on greenhouse gas (GHG) mitigation opportunities associated with producing, processing, distributing and burning fossil fuels.

The challenge of reducing GHGs from fossil fuel consumption can be roughly divided into two categories: (1) very large long-term opportunities that will require extraordinary public investment and political will and manifest over decades; and (2) smaller short-term opportunities that are being implemented now to achieve cost-effective reductions within years.

Energy industry analysts say it will require aggressive and consistent climate change policies to set major developed and developing economies on course for very large, long-term GHG reductions. Researchers from MIT's *Joint Program on the Science and Policy of Global Change* pre-

The Future of Fossil Fuels

Will the 85%+ share of global primary energy from fossil fuels erode gradually or will policy measures, technology and strategic initiatives by industry make more revolutionary changes? Various scenarios are painted in each major emitter segment and putting them together points to a short- and long-term future of new business opportunities for those providing solutions.

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dict that without such policies, fossil fuels will still provide 80% of global energy demand in 2100 (a small decrease from current levels of about 85%).

With such policies, U.S. public and private investment in GHG abatement would ramp up dramatically. **The International Energy Agency**

estimated in a 2009 report that the United States could spend \$1.5 trillion on GHG abatement strategies by 2030 to do its

U.S. Electric Power by Source:

	2010	2020	2050
Renewable Energy	4%	9%	21%
Nuclear	19%	20%	27%
Coal Total	49%	41%	30%
Coal with CCS	0%	1%	11%
Other	28%	30%	22%

Sources: 2010 U.S. Energy Information Administration; 2020 and 2050 derived from aggregated responses to CCBJ's Future of Fossil Fuels Survey 2011. Other is mostly natural gas and conventional hydro. Renewable is non-hydro renewables or wood, municipal solid waste, landfill gas, sludge, biomass, geothermal, solar and wind.

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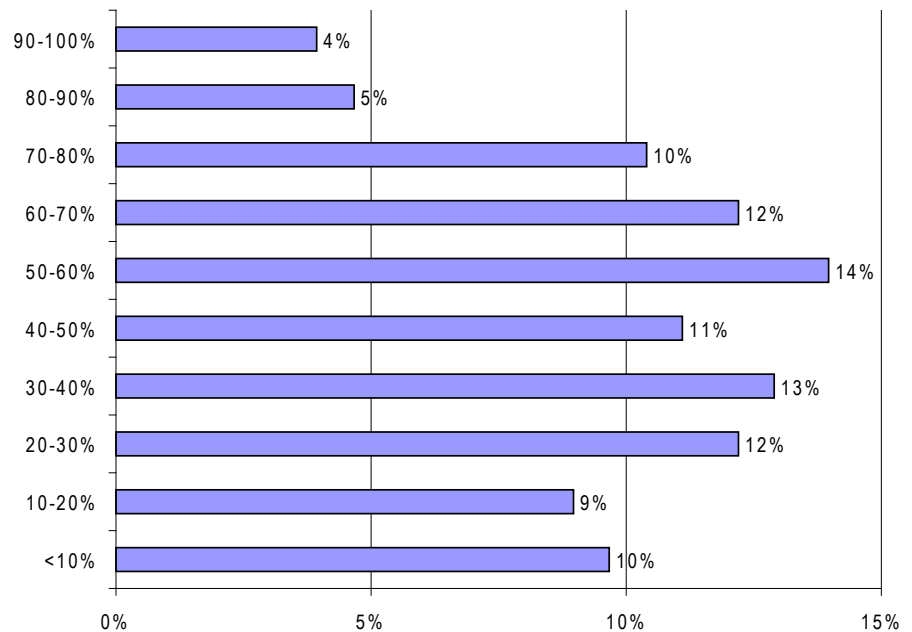
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Likelihood that Congress Will Prevent EPA from Regulating GHG Emissions Under the Clean Air Act



Source: CCBJ's Future of Fossil Fuels Survey 2011 and Environmental Business Journal 2011 Snapshot Survey combined responses to the same question: What do you think is the likelihood that Congress will succeed in preventing EPA from further regulating greenhouse gas emissions under the Clean Air Act?

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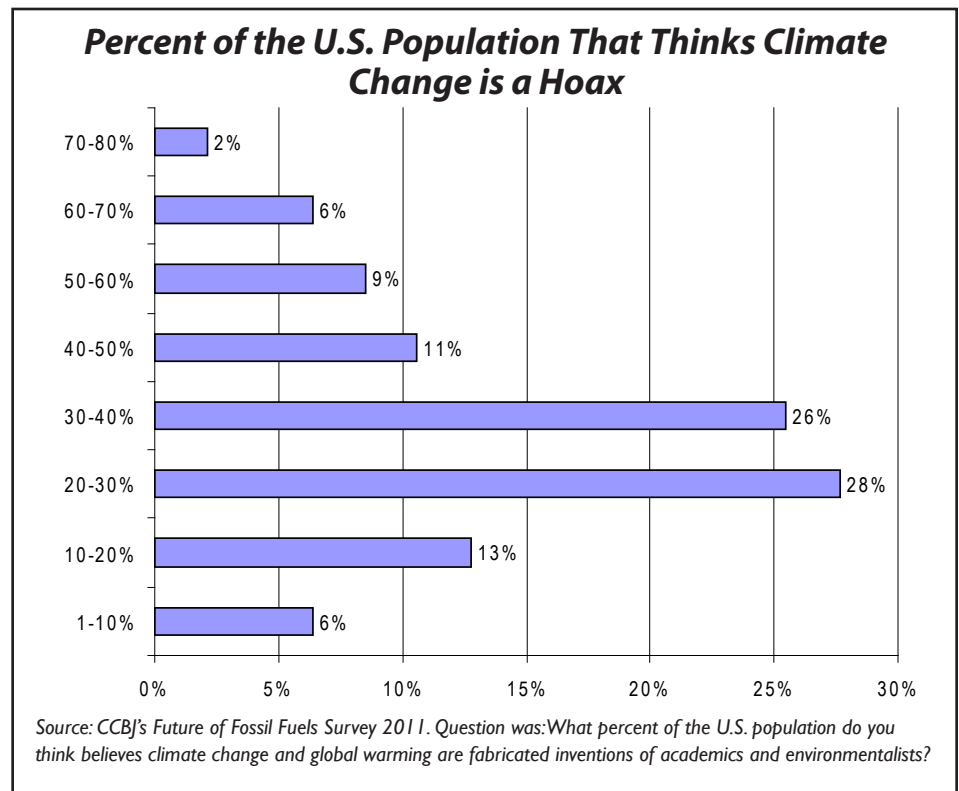
⚙ Green Buildings/Smart Growth

part to stabilize the atmosphere at 450 parts per million CO₂. This would include massive investments in end-use energy efficiency in buildings, more fuel-efficient fossil power plants, more nuclear power, carbon capture and storage and renewables. It would mean a transformation of the passenger vehicle market from one utterly dominated by internal combustion engines to one in which hybrid, electric and plug-in hybrid electric vehicles command 60% of the market.

To research the issue of future energy scenarios, CCBJ not only compiled the most comprehensive assessments by EIA, MIT and the like, but also conducted a survey of our own community in what we called CCBJ's Future of Fossil Fuels Survey 2011. Respondents included 76 consultants, engineering firms, renewable energy developers and suppliers, government, NGOs, utilities, IPPs, trade associations, academia and research institutes in roughly that order.

The CCBJ scenario presumably includes climate policy in various forms and points to a future where primary energy from fossil fuels goes from 88% in 2008 to 61% in 2050 to 40% in 2100. In the nearer term, electric vehicles are expected to account for 12% of new car sales in 10 years and 20% by 2030, while renewables go from 4% of electricity generation in 2010 to 9% in 2020 to 21% in 2050. These figures are reported as arithmetic means, but the spread of responses where respondents selected a percentage in a tight range from multiple options was quite broad, meaning there is no clear consensus from the CCBJ community. For instance while 17% believe renewables will account for less than 10% of U.S. electricity in 2050, 11% of respondents think it will be 40% or higher.

Getting to the higher levels from here seems almost unimaginable in the current economic and political climate. Indeed, to revive federal climate legislation would require a political shift more profound



than that which tilted the Congress rightward in November 2010. Andy Paterson, longtime federal analyst for CCBJ's parent company **Environmental Business International Inc.**, reminded participants at EBI's March 2011 **Environmental Industry Summit** that controversial legislation like a climate change bill would need a filibuster-proof supermajority in the U.S. Senate. "Getting 60 Democratic senators within a decade who will back a climate change bill will be impossible," said Paterson, who predicts the Democrats will lose their thin Senate majority in 2012, although not as dramatically as the political balance in the House shifted in 2010. In 2012 there are 33 Senate seats up for election and just 10 are Republican.

Perhaps political space for climate policy could re-open if extreme weather events or accelerated sea level rises convince more Americans that global warming is a serious problem. The CCBJ survey also asked respondents to estimate what percentage of Americans think climate change was a "fabricated invention of academics and environmentalists." While 8% said as many as two-thirds, the aggre-

gate average was 33% with the majority of respondents in the 20-40% range (see response chart above).

The March 2011 CCBJ survey also repeated a question identical to that posed in the January-February 2011 survey performed by CCBJ sister publication *Environmental Business Journal* on when respondents thought the U.S. would have a cap-and-trade system like that in the E.U. Almost 36% of the 278 respondents to the question said never, up from 13% to the identical question in 2009 and 25% in 2010. But the fact that 50% of the 2011 respondents said after 2018 or never (see chart on p.5) doesn't doom the market, as many analysts believe the next energy bill will contain some form of clean energy standard, an evolution of the renewable energy standards in place in 28 states in the U.S.

Two hundred dollar per barrel oil would help build the case for a clean energy standard and for transport electrification as well. And it wouldn't hurt if California's economy recovers and the state—along with Canadian provinces adopting similar climate policies—can

demonstrate by 2018 or 2020 that the costs of its cap-and-trade program have been offset, as predicted by its designers, by investments in energy efficiency, clean power and advanced fuels.

As noted in the fossil power story (p.21), one bright spot on the policy landscape is the emergence of a constituency supporting a national clean energy standard that would subsidize nuclear power, cleaner coal and perhaps efficient natural gas, along with renewables. Republican House and Senate leaders have announced their opposition to such a measure because it would raise electricity prices, but Paterson pointed out at the Environmental Industry Summit that this is an “opening position” in negotiations over a potential energy bill.

In Absence of Federal Legislation, Many Influences Prompt Fossil Fuel Industry to Invest in GHG Reduction

Fortunately for the climate change industry, there are still strong market drivers for GHG abatement in fossil fuel producing and consuming industries that don't depend on federal climate legislation. While the prospect of such a federal plan still is having some impact and is ranked fourth out of 13 market drivers rated by CCBJ survey respondents (see table on p.9), multiple regulatory and non-regulatory market drivers are prompting fossil fuel suppliers and users to invest in GHG mitigation. These include:

- the Environmental Protection Agency's emerging rules for GHGs as well as air, water and waste laws; and
- California's cap and trade law and its low carbon fuel standard, which may be emulated in the Northeast and elsewhere;
- Corporate concerns over reputation and long-term exposure to potential future GHG regulations.

EPA's new GHG and air rules are of significant immediate interest to industry, as are they to Congress, especially

the conservative aspect that seeks to curtail government activity across the board, but specifically in what some view as over-reaching by EPA. The likelihood that Congress will derail EPA is an even prospect, according to CCBJ survey respondents (see charts on p.2 and at right).

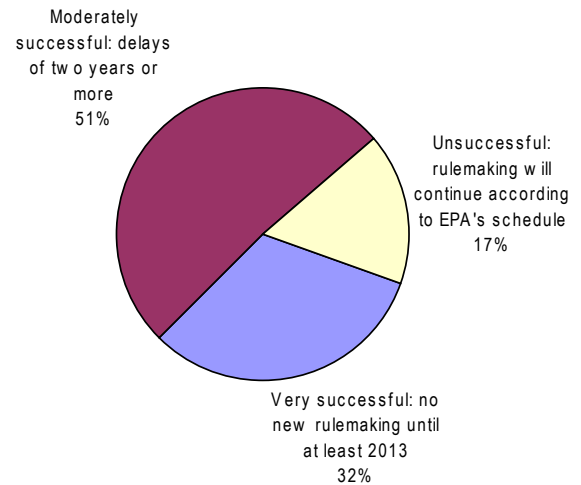
Mitigation opportunities vary from incremental improvements in combustion efficiency to wrest small gains from fossil power plants, refineries, cement and other GHG-intensive industries to large investments in combined cycle natural gas, advanced supercritical coal power plants and even carbon capture and storage. Addressing these opportunities are a wide range of consultants and vendors, many of which are profiled in this edition.

Abundant gas supplies and projections for moderate pricing for years to come are inducing electric utilities to dispatch gas power plants more readily and invest in new gas-fired capacity (see shale gas story, p.17). At the same time, for shale gas to achieve its potential, the technology's destructive environmental footprint must be mitigated; and as described herein, water treatment providers, environmental consulting firms and other vendors are stepping up to the challenge.

In pulverized coal combustion technology, there is a great deal of heat rate headroom to be had—reducing emission per kwh without carbon capture and storage technology. Researchers and vendors interviewed in this edition point to improvements of up to 3% that can be achieved through coal plant optimization strategies.

In new-build coal, efficiency gains can be much more dramatic. **American Electric Power's** decision to design and

How successful do you think Congress will be in stopping or delaying EPA's GHG rules?



Source: CCBJ's Future of Fossil Fuels Survey 2011

build its new Turk 620 MW coal power plant in McNab, Ark. to ultrasupercritical temperatures and pressure levels will result in a net reduction of about 275,000 metric tons of CO₂ (MtCO₂) annually over what a typical AEP supercritical plant would achieve. Electric utility experts and consultants see more room for ultrasupercritical coal if materials challenges can be met.

Not that there's a huge amount of investment today in new coal power technology. But utility consultants tell CCBJ that, while shale gas is no doubt the flavor of the day and indeed a “game-changer” to many, not all their electric power clients are convinced gas is the way to go. With resumption of demand growth that will come with economic recovery, new coal plants will be in some electricity generators' resource plans.

Proponents of integrated gasification combined cycle, seen by many as potentially the cleanup hitter for clean coal, have been challenged by cost issues. At least three proposed projects have been shut down by state utility regulators, and the lead IGCC batter on base—**Duke Energy**—has weathered a bruising financial, regulatory and public relations battle

to keep its Indiana IGCC plant on track for 2012 commissioning.

The CCS landscape has shifted dramatically since CCBJ dedicated an entire edition to the topic in 2008. We look at what's going on with CCS in Canada, the United States, Europe and China, with special focus on Shell's ground-breaking CCS project in Canada and the handful of commercial-scale U.S. projects that are still in the running.

Oil and gas producers are coming under the regulatory spotlight for the emissions associated with their production, transportation, processing, and distribution; and consultants and vendors are helping them comply with reporting regulations and plan GHG mitigation strategies. Some of the leading firms' activities in and perspectives on this market are explored on pages 8-13.

California, EPA Policies Take Aim at Oil and Gas

The biggest challenge for oil companies may be coming from California's low carbon fuel standard (LCFS), an unprecedented policy that will force fuel suppliers to ratchet down the carbon intensity of gasoline and diesel by blending more bio-fuels or by buying credits from suppliers of alternative low-carbon fuels—mostly electricity and natural gas.

The business implications of the LCFS are vast: a new fuel carbon credit market with revenues going to electricity, gas and maybe even hydrogen vendors; dozens of new advanced biofuel refineries; more low-carbon ethanol imports; corn ethanol producers innovating to gain a better carbon ranking from the Air Resources Board; and Canadian oilsands producers getting serious about CCS to keep their crude products flowing to California.

The influence of California's LCFS may spread. Northeast states are already using it as a template for a model low carbon fuel rule, and several Canadian

provinces have announced their intentions to pursue similar policies.

Fossil Fuel Execs Think Long Term, Have GHG Reduction on Their Minds

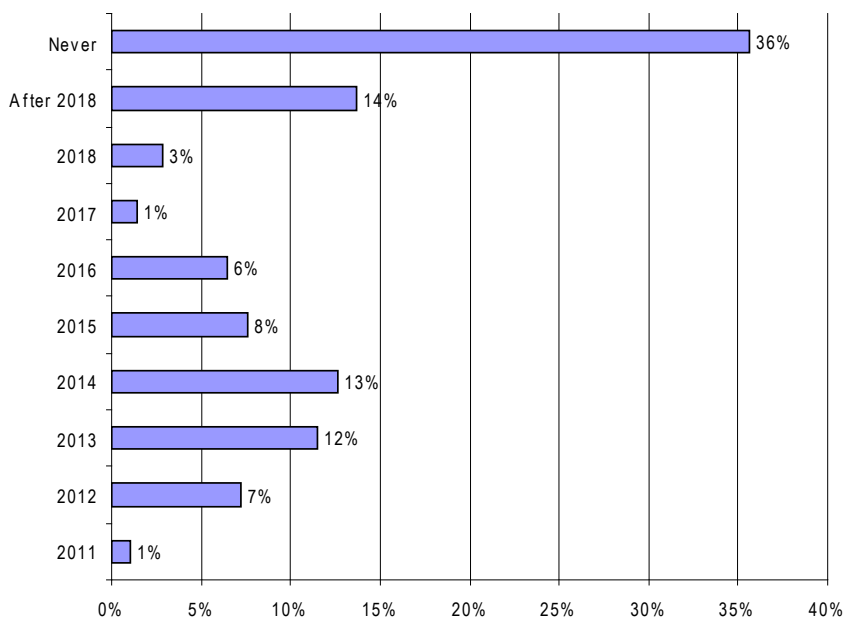
Executives and experts interviewed for this edition reported that despite the demise of any hopes for U.S. federal climate legislation in the 112th Congress, GHG mitigation is still very much on the minds of planners and managers at electric power, oil & gas and carbon-intensive industrial firms. In the power sector especially, experiences with the Clean Air Act and other environmental laws have shown that the priorities of legislative majorities and executive branch agencies shift significantly from term to term. Moreover, court decisions can change the intensity and pacing of regulatory requirements.

But power plants, oil refineries, petrochemical manufacturers and other carbon-intensive assets have long lifecycles, and prudent owners look decades into the future at potential and likely future regulatory scenarios. "We inherently take an asset lifecycle view," said Paul Hardisty,

global director, EcoNomics and Sustainability for consulting engineering firm WorleyParsons, which has a large client base of oil & gas companies. "Decisions you make now will lock in equipment and infrastructure that will last for a very long time, and we all know that the world is changing. Carbon matters," said Hardisty. "Carbon is being priced in some jurisdictions and will almost certainly be priced globally within the asset lifecycle of much of the industry's facilities."

"If a client is talking about investing in a new facility or making capital upgrades to existing facilities, they're looking at 20-, 30- or 40-year decisions. Over that period there's a very high likelihood that in just about every jurisdiction there's going to be some form of direct or indirect carbon pricing." In other words, long-term scenarios in power pay little credence to short-term political sways. How and when industry follows the power utilities in incorporating the inevitability of climate policy into their planning will certainly be of some interest to the climate change industry. ⚙

Opinion on U.S. Cap-and-Trade System



Source: CCBJ's Future of Fossil Fuels Survey 2011 and Environmental Business Journal 2011 Snapshot Survey combined responses at the same question. Question was: When do you think the United States will institute a carbon cap-and-trade system similar to the EU-ETS system in Europe? 2009 response: 68% said 2010-2012 and never was 13%; 2010: 37% said 2010-2012 and never was 25%.

The Future of Fossil Fuels: Scramble or Blueprints?

Will pressures to achieve energy security trump climate change policies?

Formed from biomass over geological time, coal, oil and natural gas are irreplaceable, non-renewable, and responsible for more than 85% of primary energy demand worldwide.

Because of their finite nature, humankind will eventually be forced to find substitutes, but not very soon according to many analysts. "The world is not running out of fossil fuels," state John Reilly and Allison Crimmins of MIT's Joint Program on the Science and Policy of Global Change in Myth vs. Fact, a guest article in the January 2011 edition of *Mechanical Engineering*.

According to Reilly and Crimmins, without laws and regulations that create a robust carbon price, fossil fuels will still supply nearly 80% of the world's primary energy demand in 2100. Coal will be at least 40% cheaper than nuclear energy and renewable energy. These low-carbon sources will grow dramatically, to as much as eight to 10 times their current capacity levels, but still provide just 20% of global energy, according to the authors.

Technology will make unconventional gas resources—shale gas, coal bed methane, tight gas and methane hydrates now "locked in frozen sediments beneath permafrost and the seafloor"—abundant. Although global oil production will be well past its peak, oilsands, shale oil and coal-to-liquids technology will grow through the century to satisfy demand for liquid fuels, according to the authors.

These are the MIT group's conclusions from models run with their Integrated Global System Modeling framework, which blends natural and social sciences to simulate change and assess policy impacts. Other analyses come to similar conclusions, with shades of differences.

Shell Describes Two Energy-Climate Scenarios

Shell believes the world's energy-climate future hangs on a key variable: the extent to which national leaders collaborate to develop a global "blueprint" for sustainable development or "scramble" to secure their own energy supplies, pushing energy efficiency and climate policy into the future.

Scramble Scenario

In the Scramble scenario, immediate pressures to achieve energy security trump demand management policies. National government attention falls to supply side levers resulting in a resource scramble waged by nations and between nations. Actions to address climate change become subordinated until major events – physical effects like floods and severe storms – drive responses. Action to tackle energy demand and promote efficiency comes only when supplies become tight and continued economic growth can only be achieved with better management of constrained resources. The energy system in Scramble is characterised by discontinuities as a result.

Blueprints Scenario

In the Blueprints scenario, action to manage energy use better is driven by a combination of concerns both about the available supply of resources but also environmental interests and the commercial opportunities presented by a transforming energy system. Alliances to drive better economic and lifestyle prospects are increasingly initiated by coalitions recognising new mutual interests, then adopted at a local level and increasingly mainstreamed across geographies where interests are shared. A patchwork of policies drives businesses to lobby for regulatory clarity and drive early adoption of new technologies and innovation.

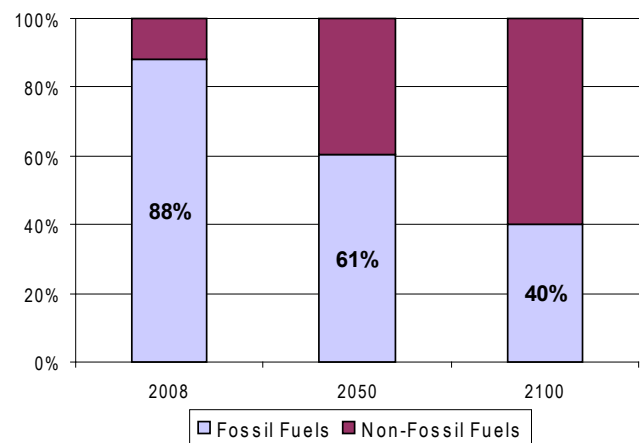
Shell (2010 revenues of \$368 billion) warns of an enormous energy gap—as much as 400 exajoules, the equivalent of what the entire energy industry delivered in 2000—looming sometime within the next 40 years.

"Developing nations, including population giants China and India, are entering their most energy-intensive phase of economic growth as they industrialise, urbanize, build infrastructure, and increase their use of transportation," wrote Shell's scenario team in a February 2011 Signals and Signposts report.

Shell's team and the MIT modelers

agree that without robust climate policy, global average temperatures will probably increase beyond the 2° warming that many scientists warn will trigger catastrophic impacts.

Global Primary Energy from Fossil Fuels



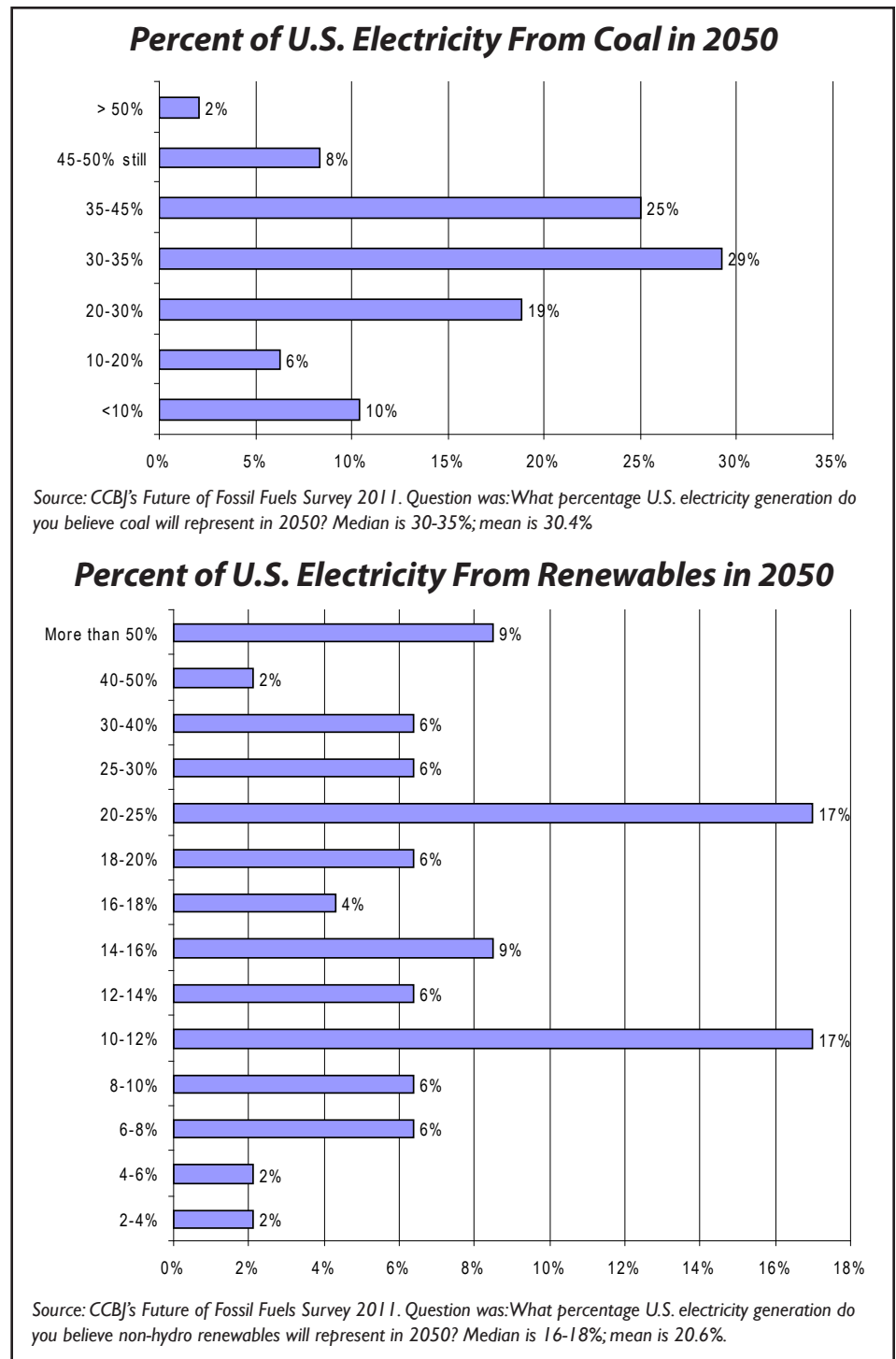
Source: CCBJ's Future of Fossil Fuels Survey 2011. Question was: Fossil fuels accounted for about 88% of global primary energy in 2008. What percentage of global primary energy consumption do you think will come from fossil fuels in 2050/2100? (As an example, primary energy includes the source of electricity used for electric cars.)

Shell, which employs 93,000 people in 90-plus countries and produces 3.3 million barrels of gas or oil a day, says the shape of the world's energy-climate future hangs on a key variable: the extent to which national leaders collaborate to develop a global "blueprint" for sustainable development or "scramble" to secure their own energy supplies, pushing energy efficiency and climate policy into the future.

Shell highlights competing events and pressures that are now determining whether the future looks more like a scramble or a blueprint. On the Scramble side of the ledger are growing tensions over hydrocarbon resources in the South China Sea, China's push for energy security, and the failure to adopt climate policy in the U.S., Australia and Japan. On the Blueprints side are "minilateral" actions between small numbers of influential countries such as the Copenhagen Accord signed by the U.S., China, India, Brazil and South Africa; local and regional climate change commitments like the Western Climate Initiative; the spread of feed-in tariffs for renewable energy; and WalMart's commitment to reduce its carbon footprint by 20 million tons by 2015.

Which scenario appears more likely at this point? Since 2008 when Shell first published its scenarios, events have "shifted radically" toward the scramble playbook. While the scientific consensus on climate change "is becoming increasingly pessimistic about the potentially devastating effects" the great recession has undercut the "the environment as a vote-winning issue." Climate change contrarians are on the rise as "expert and public opinion diverge," wrote the Shell Scenario Team.

The CCBJ Scenario assumes the inevitability of a direct or indirect price on carbon and results in a hybrid of climate, energy security and economic policies with continued influence and adaptability of the leading global energy suppliers to maintain a significant share. Gradually



converging national and regional policies are expected to simulate the growth of non-fossil energy to reach the 60% share forecast for 2100 by the CCBJ survey.

How public opinion in the United States, a key player in any international climate policy agreement, can be shifted is beyond Shell's scope, and indeed CCBJ's. A weather catastrophe with an obvious climate change signature might turn

things around, or at least have a more favorable influence than the brutally cold winters much of the country suffered through in the last two seasons. Then there's the Boiled Frog Scenario which follows along the lines of the old adage of how you boil a frog: not by putting him in boiling water, but by putting him in temperate water and slowly cooking him to death. Mankind surely hopes this isn't the most likely scenario. ⚙

Oil & Gas Industry to Measure and Report GHG Emissions Under EPA and California Policies

Regulations expand dramatically; covered emitters look to C&E and professional service firms for help.

While not nearly as large a greenhouse gas (GHG) contributor as the electric power sector, which emitted about 2,154 million metric tons of CO₂ equivalent (MMtCO₂e) GHGs in 2009, the oil and gas industry is the second largest emitter category, producing a hefty proportion of the 739 MMtCO₂e emitted from U.S. industrial sources in 2009, according to the **Environmental Protection Agency** (EPA). This doesn't count gasoline and diesel combustion, which is primarily responsible for the nation's enormous transport carbon footprint of 1,719 MMtCO₂e in 2009.

Stabilizing and reducing transport GHGs can be addressed through vehicle fuel efficiency standards, alternative fuel vehicles, low-carbon fuel standards and behavior-changing strategies such as inducing more drivers to walk, bike, carpool or use transit instead of driving single-occupancy vehicles. While these strategies aren't accelerating at the pace that climate change policy advocates would wish, a combination of federal fuel efficiency standards that will tighten over the next decade and emerging low-carbon fuel standards are shaping up to have very large impacts on transport GHG emissions. (See p.13 for low-carbon fuel standards in California and the Northeast.)

In the shorter term, oil and gas producers are coming under the regulatory spotlight for the emissions associated with their production, transportation, processing, and distribution. Oil and gas exploration and production (E&P) facilities, refineries, natural gas processing plants

and gas pipelines are significant sources of GHGs both from fossil fuel combustion to run boilers and heaters and from methane that is flared or vented (accidentally or by design, as in the case of reciprocating compressors used in the gas industry).

Oil and gas companies have been increasingly measuring and monitoring these emissions, with their level of effort dependent on the region they operate in or the sustainability and climate change goals of the firm. In Europe, refineries and other sources are covered by the European Union Emissions Trading Scheme. In the United States and elsewhere, voluntary reporting and even mitigation measures have become increasingly common since the late 2000s. Many of these measures are cost effective because they reduce energy costs and, in the case of methane capture, increase the volume of marketable gas.

Under EPA's Greenhouse Gas Mandatory Reporting Rule, power plants, fuel suppliers, oil refineries and some larger upstream production facilities were required to measure GHG emissions beginning in 2010 and report by March 31, 2011. (At CCBJ deadline, EPA announced an extension to Sept. 31 as it fine-tunes its electronic reporting system.) These rules include the requirement to report on the emissions associated with combustion of each refinery's end-use products as well as the emissions associated with the natural gas sold by local distribution companies.

Oil Industry Opposes Rule-Making, Arguing Economics and Competitiveness

Last year, EPA issued Subpart W of its reporting rule for the remaining portions of the oil and gas sector, including upstream E&P and downstream natural gas pipeline and delivery systems.

EPA is also proceeding with rulemaking around GHG new source performance standards for refineries (as well

Oil & Gas Industry in the Spotlight

Consulting and C&E firms report a surge in demand for compliance planning and implementation, GHG monitoring and measuring, software integration, and benchmarking studies as oil & gas clients navigate new climate change regulations. Why? Under EPA's GHG Mandatory Reporting Rule, power plants, fuel suppliers, oil refineries and larger upstream production facilities are required to measure GHG emissions and report by the end of March (revised deadline Sept. 31). In California, companies are in the early stages of planning compliance strategies in response to the state's cap and trade program under AB 32. California's rule has some unique requirements, including energy efficiency audits for some.

as power plants), which the petroleum industry vigorously opposes. "Our members are strongly incentivized already [to implement] energy efficiency [measures]," said Howard Feldman, director of scientific and regulatory affairs for the **American Petroleum Institute** in a February 4, 2011 news conference.

"The primary costs of producing fuel are the costs of the crude and the cost of energy. Refiners are in a competitive market [where] everybody is watching the bottom line [and] trying to reduce energy expenses and be as energy-efficient as possible," said Feldman. "What will EPA propose on top of that?"

API's Director of Federal Regulations Khary Cauthen highlighted the association's support for congressional bills to put EPA out of the GHG regulation business entirely. EPA's "onerous and costly requirements" would hurt the U.S. economy while the country is "still attempting to recover with unemployment still at 9 percent," said Cauthen.

Cauthen touted the petroleum industry's investments in GHG mitigation technologies, citing API's 2009 study by

T2 Associates and the Center for Energy Economics at The University of Texas, that estimated U.S. oil and gas companies had invested more than \$58 billion from 2000 through 2008 in energy efficiency, combined heat and power, renewable power, methane capture and other GHG mitigation technologies.

“We have substantially lowered our environmental footprint in the last decade,” said Cauthen. “There is a way forward to achieving environmental goals without discouraging business expansion and job growth. This country’s climate change policy should not be done by the federal bureaucracy using a law never intended for this.” There are strong counter-arguments to API’s view that the Clean Air Act shouldn’t be used to regulate GHGs, most notably the U.S. Supreme Court’s 2007 decision agreeing with the state of Massachusetts and other plaintiffs that EPA had to evaluate whether GHGs should be regulated under the act, which led to the agency’s December 2009 endangerment finding.

There’s also the December 2010 Settlement Agreement between the agency and 13 states and environmental groups that sued for judicial review of the agency’s Bush-era final rule on new source performance standards (affecting new and substantially modified facilities) for power plants and refineries. In the settlement, EPA agreed to submit a proposed rule for refineries before the end of 2011 and a final rule by November 2012.

Given the investments highlighted by Feldman and Cauthen, the industry may not have all that much to fear from an EPA GHG performance standard. According to a story in *BNA Environment Daily*, at a Feb. 4 “listening session” EPA’s Assistant Administrator for Air and Radiation Gina McCarthy told the audience that new source performance standards (NSPS) for power plants and refineries will be based on “readily available, very cost-effective reduction opportunities.”

Ranking of Market Drivers for Reducing GHG Emissions in the USA

	Very strong influence	Strong influence	Moderate influence	Little influence	No influence
EPA GHG permitting rules	31%	52%	13%	2%	2%
State or provincial policies specific to GHGs	29%	40%	27%	4%	0%
EPA permitting rules for air, waste and water	29%	38%	25%	8%	0%
The prospect of future federal legislation to reduce GHGs	22%	28%	26%	22%	2%
Direct pressure from consumers or the public	13%	29%	42%	17%	0%
Managing or reducing potential liabilities	9%	36%	28%	28%	0%
Personal commitment by senior management or board members	8%	31%	41%	18%	2%
Public relations to convey a sustainable or green image	2%	29%	53%	16%	0%
Investor pressure	13%	23%	38%	25%	2%
GHG mitigation commitments from national trading partners	6%	21%	32%	38%	2%
Pressure from up the supply chain (manufacturers/retailers)	4%	15%	39%	33%	9%
Banking credits from an existing trading scheme	4%	15%	35%	38%	8%
Pressure from down the supply chain (suppliers/raw materials)	4%	8%	33%	50%	4%

Source: CCBJ’s Future of Fossil Fuels Survey 2011. Question: To what extent do you think each of the following will influence North American major emitters of GHGs to plan for/begin reducing GHGs over the next three to five years?

McCarthy said in developing the NSPS rules, the agency would follow the same approach it has taken with its best available control technology (BACT) document for power plants issued in November to fulfill the prevention of significant deterioration requirements of the Clean Air Act. As reported in CCBJ’s December 2010 edition, the BACT serves as guidance for state regulators to use when they review permit requests from owners of new electric generating plants that will emit 75,000 metric tons per year of CO₂e or more—or facilities being substantially modified to the extent that annual emissions will increase by at least that amount. The BACT guidance stops short of requiring applicants proposing new coal power plants to switch to natural gas turbines, emphasizing instead efficiency of combustion systems.

Regardless of what happens with EPA’s

current rulemaking, all segments of the oil and gas industry are moving to measure and report their emissions to comply with EPA’s reporting rule. In California, they’re also in the early stages of planning compliance strategies relative to the state’s cap and trade law. With no large in-state coal power plants, refineries constitute most of the top GHG emitters in the state, with Chevron’s Richmond facility at the top with an estimated 4.8 MMtCO₂e in 2008.

Companies Seek Help Navigating California’s Audit Requirements & Efficiency Benchmark

California’s rule includes some unique requirements, such as mandatory energy efficiency audit for emitters with more than 500,000 MtCO₂e annually, and a potentially advantageous efficiency benchmark for covered industrial companies.

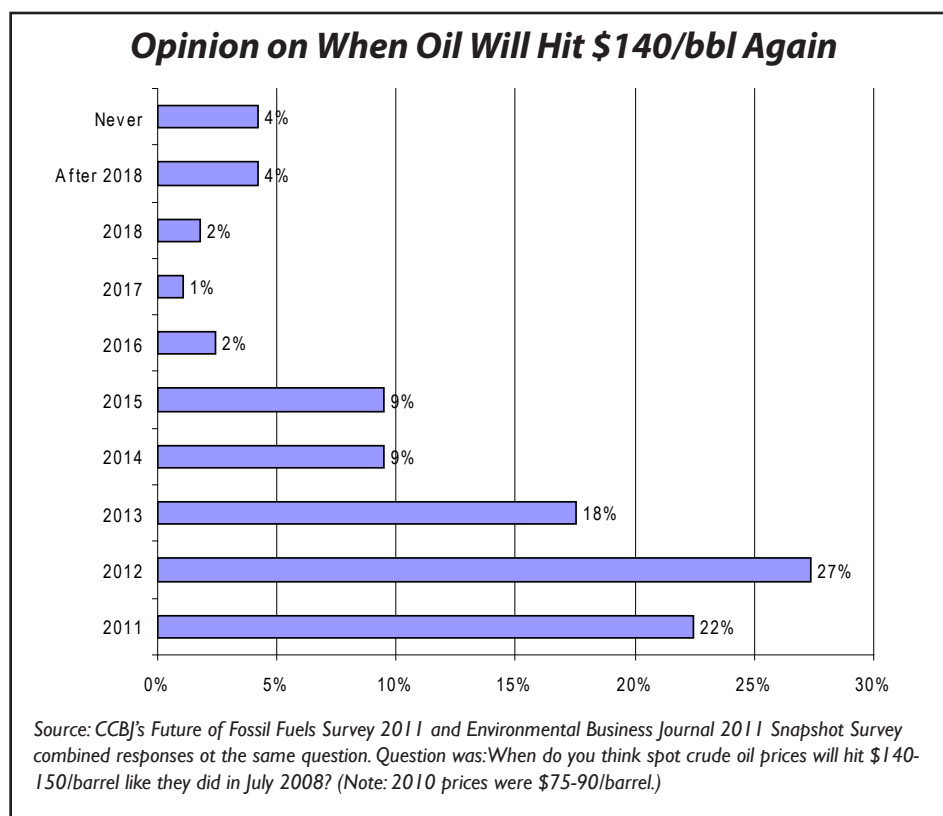
According to Victoria Evans, national GHG management services practice leader for engineering firm URS, to comply with the audit requirements and qualify for the efficiency benchmark, refineries have to begin measuring emissions from disparate boilers and heaters, many of which haven't been metered in the past.

These and other quirks and challenges in the California rule and the federal reporting requirements are generating business for firms such as URS, ERM and other environmental consulting and engineering (C&E) firms with expertise in air quality and a track record in environmental compliance work with the oil and gas sector. As noted in CCBJ's Feb/Mar 2010 C&E edition, some of these firms also advise oil and gas clients on the larger strategic issues involved in wresting maximum long-term value from carbon pricing, and in this arena the C&Es compete with management consulting and professional service firms with industry expertise.

Irbaris: Consider "Indirect" Effects of Future Regs to Maximize Value

For David Hampton, managing partner of Irbaris, a London-based management consulting firm with a focus on sustainability and climate change, oil and gas companies considering whether to build or expand a petroleum refinery must consider long-term trends in their markets and the "indirect" effects of pending and future environmental regulations.

Along with the more obvious factors such as price trends for crude, energy and carbon, refinery owners must weigh different scenarios for the adoption curve of electric vehicles and hybrid-electric vehicles in their market territory and the evolution of fuel-economy and low-carbon fuel standards in jurisdictions where they sell fuel. "The economics of refineries are very sensitive to the capacity utilization at which they're running," said Hampton.



While electric vehicles and plug-in hybrid electric vehicles aren't flooding the U.S. market in 2011—and may not amount to more than 1% of U.S. passenger vehicle sales in 2020 if they follow a similar adoption curve as first-generation hybrids like the Toyota Prius—Hampton says the refinery owner has to consider trends well beyond 10 years out as well as the possible impact of step-change disruptive technology or market developments. If battery technology continues to improve, charging infrastructure gets built and oil prices continue to rise, a refinery could find its market and its margins declining significantly after 2020. "With a major new refinery, if you make the investment today it might take several years to come onstream and another 10 to 15 years in which to earn the required returns on the initial investment," said Hampton.

Refining is also a trade-exposed industry, meaning that if a California refinery owner finds its margins squeezed by the carbon prices in California, it could lose business to refineries across the state borders (although the state's efficiency

benchmarking procedure will provide some protection; see below). Hampton has seen this play out in Europe, where oil majors have been selling off refinery assets. "They're selling them to private equity vehicles or secondary companies, and whether those buyers really understand what it is they're buying and what the economics might look like long term is quite questionable," he said.

At the same time, export refineries are being developed in India and around the Persian Gulf that "may well have a cost advantage" over European competitors. He said the European Union is weighing the adoption of border measures—essentially tariffs for carbon-intensive products imported to Europe from regions without GHG caps—to prevent emissions leakage and safeguard domestic refineries.

"But there again, the focus is only on the primary effect of there being a cost of carbon, without considering all the second-order impacts from factors such as fuel efficiency and low-carbon fuel standards," said Hampton. "Yes, governments can kind of level the playing field as far as

who's paying carbon taxes or a price for carbon under cap and trade, but they can't change the fact that the market will look very different in 10 years."

On the other side of the coin, many oil and gas companies overlook opportunities for their long-term enterprise value that will arise with carbon caps and changing markets, according to Hampton. He described a consulting project for a green-field refinery developer in which the client "thought quite carefully about the product slate [diesel, gasoline, petrochemicals, etc.] and how to power the refinery in the context of it coming into a carbon-constrained world."

"By narrowing down the product slate and taking advantage of some resources that were around them, they came up with a low-carbon fuel refinery with a dramatically lower set of emissions than existing conventional refineries of comparable size," said Hampton. "We like to help clients go from saying 'I want to minimize my cost of carbon' to 'I want to maximize performance and financial value in a world where everyone is concerned about carbon, water and other environmental issues.'"

ERM Addresses Ripple Effect of EPA's Subpart W on Oil & Gas Clients

For ERM, Subpart W of EPA's Greenhouse Gas Mandatory Reporting Rule aimed at the oil and gas sector has sparked rapid growth in GHG measuring and reporting projects. "They've been bringing us in at different levels," commented Lisa Campbell, ERM's climate change services practice lead for the Oil and Gas Sector. "Many of our existing clients are engaging us to help lead or provide advice to lead their initiative to develop compliance plans and then to implement those compliance plans."

"We've done a wide range of projects, often starting with an applicability analysis, looking at what their reporting boundaries are for facilities, and determining

whether or not certain facilities will need to report," said Campbell. "That's the first step. Then we do a gap assessment to map what data they are currently collecting in their various existing systems and identify what additional information needs to be collected. Then we'll help them get the processes and tools in place to capture the missing data." In addition, there are GHG monitoring plans that need to be put in place by the end of the first Quarter 2011.

In some cases, GHG reporting can be integrated into a client's existing environmental management information software database, and in others the company needs to develop new GHG inventory systems, including shopping for new software. "Many times we help clients define needs, select best fit software, and implement these systems to streamline the reporting," said Campbell.

For larger companies, the amount of data sources can be immense, according to Campbell's colleague Toby Hanna, ERM's air & climate change practice leader for the firm's Northern Division comprising nearly half of the United States and all of Canada. "Many of our clients have over 5,000 active well sites and some have over 10,000," said Hanna. "There are contractors that have to be tracked down [to report emissions] and other ripples spreading out from Subpart W. ... At each one of these locations there are multiple pieces of information that need to be tracked throughout the year, and all that data is needed to report to the EPA. It can be a real data mess if it's not organized in a systematic way."

Campbell and Hanna estimate between 50 and 100 ERM employees work on such projects part or full time, including air quality and information systems specialists. Project billing can range from \$100,000 to \$1 million or more depending on the level of complexity and whether software and systems integration solutions are included, according to Campbell. Since the beginning of 2010,

the company has performed at least 160 contracts driven by GHG reporting, and in the first-quarter of 2011 the workload was peaking as the March 31, 2011 reporting deadline approached.

Campbell and Hanna anticipate some Subpart W reporting projects will be long term, especially those for upstream producers who are using—with EPA's approval—engineering estimates for the first phases of reporting. For a natural gas producer, for example, the reporting rule allows EPA to initially accept data that is based on the company's existing methods of accounting for methane losses from various sources.

"Eventually EPA will want all reporters to strictly follow the prescribed methods in the rule which mandate detailed information such as the actual count of natural gas pneumatic devices at all active wellheads, and other very specific information that is not currently tracked by most producers," said Hanna. ERM is advising some clients on the best strategies to accomplish that.

"They don't necessarily have to go out and buy equipment like flow meters and gas analyzers. But in some cases it may make their lives easier to do that because some of the alternatives may be more complicated," said Campbell. "They do have to do things such as annual leak screening for certain facility types like gas processing plants."

Hanna and Campbell see this as a growing business driver especially in the Northeast with development of gas production in the Marcellus Shale. "I don't think there are a lot of these analytical resources there right now, so with the production that's going on now there's a growth opportunity for businesses to perform these services."

For midstream and downstream natural gas companies, monitoring and measuring fugitive emissions is the main challenge to meeting Subpart W require-

ments according to Hanna and Campbell. “There’s equipment to buy, firms to hire and resources to deploy to figure out how to manage all that information,” said Campbell. “EPA put four methods in the rule for doing that type of leak checking: Infra-red, laser, sound and ionization potential technologies are all options, and each entails a detailed protocol prescribed by EPA.” Direct measurement programs are required at least once per year, and many companies are faced with finding outside contractors that can perform these services for 2011, while companies work to integrate the measurements into their routine.

For gas utilities (also known as local distribution companies), there’s frustration and a lawsuit by an industry association because the EPA’s required methods for monitoring gas leakage don’t match up with what the utilities are currently required to do under Department of Transportation regulations, said Hanna.

While all this activity is so far driven just by the reporting requirements, Campbell says that many companies, oil and gas majors in particular, are “looking at what’s coming next and starting to prepare. They’re forming internal teams and I’ve been asked to participate on one of those teams focused on the longer term drivers and strategies to best prepare for operations in a carbon-constrained environment.”

While climate change legislation is stalled for the time being, companies know that there’s a significant risk it will be revived before the end of the decade—and that EPA’s NSPS standards combined with emerging state standards will impact their businesses. Hanna points out that the GHG emissions data will all be public and listed next to company names. “That fact, combined with concerns about future regulatory risk, has companies talking about GHG reduction strategies while they are preparing their GHG reports,” he said.

URS Plans Energy Efficiency Improvements for California Clients; More Benchmarking Studies Expected

For URS, projects to measure and report GHG emissions as well as plan for abatement scenarios are coming from existing and new clients in oil and gas, petrochemicals and other industries, according to Evans. “This is one of those areas where existing clients will call and say, ‘there’s this new regulation, can you help me determine its impacts?’” she said. “And new clients find out about us, often based on a seminar or presentation we’ve given.”

Like other engineering firms working in California, URS is helping clients sort out and plan to comply with or take advantage of some unique aspects of the state’s climate change law, AB32, the cap and trade provisions of which take effect in 2012. One facet of AB32 imposes new requirements on about 60 of 600 covered facilities, including many refineries. “There is an energy efficiency improvement requirement for facilities emitting more than 500,000 metric tons of CO₂e annually that includes an assessment of retrofit potential and an energy audit,” said Evans.

Additionally, many covered industrial operations like petrochemical, chemical and cement plants will likely want benchmarking studies in order to qualify for more allowances under the Air Resources Board efficiency based benchmarking program. With this element in the rule, ARB will award allowances to facilities based on 90% of the average carbon intensity of their respective industry, be it fuels, glass, cement, steel, pharmaceuticals, etc. Under ARB’s rule, additional assistance ‘points’ are included in the allowance calculation for energy intensive-trade exposed entities.

That will award the most energy- and carbon-efficient operators with a higher proportion of free allowances. As efficient producers increase their production, and so demonstrate to ARB, their allowances

will go up. (Power plants aren’t included because they are not exposed to competition from uncovered out-of-state manufacturers since electricity imports are covered under AB32.)

But Evans says that to take advantage of the opportunity, most classes of facilities have to analyze their energy usage in ways they haven’t before. “The efficiency of the facility is linked to its fuel use and the use of the heat or power that is produced,” said Evans. Facility operators have to measure the combustion efficiency of multiple heaters and boilers—the number can run into hundreds on a large oil refinery—many of which are not currently submetered.

“It means performing more analyses than would be performed for the GHG inventory or reporting, and more in-depth studies,” said Evans. URS has performed several of these projects for industrial clients in California and for refineries outside California that were gauging their standing against similar efficiency benchmarks proposed in the unsuccessful Waxman-Markey federal cap and trade legislation, according to Evans.

“We’ve conducted this level of work for some clients, but so far the reports have been for internal use only. In California, this would have to be done for each plant that has an interest in their standing against the benchmark.” From experience on out-of-state benchmarking projects for refineries, she anticipates that California refineries will demonstrate wide ranges in carbon-intensity. “It could be for many different reasons, including for example, to what extent they’re combusting petroleum coke versus natural gas.”

The cost of these studies varies depending upon the size of the facility and the complexity of the operation. Much of the work is done by air quality engineers who “are experienced in performing fuel calculations,” said Evans. For GHG mitigation and compliance planning, “When

we start asking more detailed questions about what could be done to make a facility more efficient, URS utilizes specialized staff who understand the particular industrial processes.”

At this point, Evans thinks few covered emitters have performed the required benchmarking, so there’s a lot of potential business on tap—business which can lead to additional consulting as emitters start planning efficiency improvements to generate allowance value or comply with their carbon caps. And as facilities grow or expand, they’ll likely need additional efficiency analyses. “If they expand their operations, run more hours, or run at a heavier load, their emissions are going to go up along with their production and they may need to perform new benchmarking to demonstrate their efficiency,” she said.

Outside California, much GHG inventory and reporting work for oil and gas companies is being driven by the EPA reporting rule, according to Evans. Evans indicated that URS’s business has been very comparable to that of ERM, which has performed at least 160 such projects.

Many projects touch on GHG mitigation for natural gas processors and pipeline operators. URS has been involved in helping clients improve their programs to capture fugitive emissions at production sites, processing facilities and pipeline systems and to recover waste heat at pipeline compressor stations. “One client recently engaged URS to help them obtain a LEED certification for some natural gas compressor stations,” said Evans. “They are also assessing the possibility of achieving carbon neutrality for construction of the pipeline.”

Like in many other new markets with uncertain regulatory footing, consulting engineers and other solution providers expect some projects and markets to pop up in unexpected places. ⚙

Low Carbon Fuel Standard Breaks New Ground, Sets Model for Other States

New carbon credit markets will be formed to support electric and natural gas vehicle fueling.

With its low carbon fuel standard (LCFS), California’s Air Resources Board is putting the state’s fuel suppliers on a carbon diet. The LCFS rule breaks new policy ground in many respects: As ARB staff wrote in a March 2009 summary, “There are no similar existing regulations [nationally or internationally].”

The implications of the LCFS are enormous and far reaching. New carbon credit markets will likely emerge within the LCFS to support electricity and natural gas vehicle fueling, with revenues going to players ranging from large electric and gas utilities to entrepreneurial vehicle charging and compressed natural gas (CNG) service stations—maybe even hydrogen vendors.

Advanced biofuel manufacturers could build dozens of new biorefineries around the state or elsewhere in the United States. Low-carbon ethanol imports from Brazil may increase—despite the \$0.54 per gallon tariff on the imports—while Midwest corn ethanol producers are already innovating to become more carbon-efficient and gain a better carbon ranking from the ARB. High-carbon crude producers such as Alberta’s oilsands producers have another incentive to get their carbon capture and storage projects online so they can reduce the California carbon scores of their crude products.

How LCFS Works

The LCFS works by requiring gasoline and diesel fuel producers and importers, starting this year, to demonstrate to ARB that the total volume of transportation fuel they sell in the state produces 0.25%

LCFS Effects Will be Far Reaching

LCFS works by requiring gasoline and diesel fuel producers to demonstrate that transportation fuel sold in the state produces progressively fewer carbon emissions than standard products. Corn ethanol producers have sued over how carbon intensity is calculated, but the LCFS is credited with inspiring biofuel producers to get creative. A key factor in how the LCFS plays out is the pace of commercialization of advanced biofuels.

less carbon emissions than standard products, a value set at 95.86 grams CO₂ emissions per megajoule (MJ) of energy for gasoline and 94.71 gCO₂/MJ for diesel. The carbon-intensity target continues declining yearly to reach a 10% reduction in 2020.

According to ARB, the LCFS provides flexibility to producers and importers to determine how best to meet these requirements through any feasible mix of fuels with different carbon intensities; the use of LCFS credits, obtained from parties who have reduced their carbon emissions more than the required levels, is also allowed to meet requirements.

Carbon intensities are assigned to various fuel types based on ARB-defined “pathways” that take into account lifecycle emissions from production, processing, transport and indirect land-use impacts. For example, sugarcane ethanol is considered to have very low direct emissions—from 12 to 32 grams per MJ depending on factors such as whether the plantation is generating power from its waste—but high indirect emissions—46 grams per MJ—due to the fact that sugarcane displaces quantities of food and feed crops, according to ARB.

These displaced crops must be replaced, causing grasslands and forests to be converted to agriculture. The land use change emissions associated with corn ethanol are currently estimated to be somewhat lower,

at 30 gCO₂/MJ.

Put in motion by a 2007 executive order from former Governor Arnold Schwarzenegger, the LCFS is a “discrete early-action” measure under California’s Global Warming Solutions Act of 2006 (AB32). ARB expects the LCFS to yield 15 million metric tons of CO₂-equivalent emission cuts cumulatively by 2020, about 10% of the state’s total goal under AB 32.

Fuel producers’ LCFS obligations are in addition to the mandatory emissions caps for their refineries under California’s cap and trade law. Under that program (see p.X), refineries, will reduce emissions through measures such as upgrading the efficiency of boilers and heaters, or buying credits from sponsors of projects in urban forestry, dairy methane capture and other approved offset methodologies.

After an epic stakeholder consultation process, the ARB board approved the LCFS in April 2009. Many elements of rulemaking are still evolving, with workgroups and advisory panels meeting to consider such measures as revising carbon intensity factors for various biofuel types to reflect innovations in biofuel production or advancements in the science of lifecycle assessment. ARB is also fielding continuing objections from the petroleum industry and defending the LCFS in several lawsuits by U.S. corn ethanol producers and petrochemical refiners.

Land Use Impacts Considered in Calculating Carbon Intensity; Corn Ethanol Producers Object

After much debate and despite uncertainty and some criticism from researchers (many of them from farm state colleges), ARB determined that a credible LCFS must consider indirect land-use impacts—a decision also taken by the U.S. Environmental Protection Agency for its Renewable Fuels Standard and the European Union, the only other large jurisdictions to enact a carbon based fuel content standard.

As ARB points out, if acreage now devoted to raising food, animal feed and fiber is converted to biofuels production to satisfy the California market, “Some of that acreage is replaced by the conversion of non-agricultural land to agriculture uses [which] releases significant GHGs into the atmosphere.” As mentioned above, ARB estimated that 30 grams per MJ of CO₂-equivalent is released for corn ethanol.

Represented by the trade groups **Renewable Fuels Assn.** and **Growth Energy**, the ethanol industry has filed suit in federal court to challenge, among other things, ARB’s inclusion of land-use impacts in calculating corn ethanol’s carbon intensity. The plaintiffs say land-use impacts assessments are a vague science and that California’s “penalty” on corn ethanol would thwart Congress’s intention in enacting the Renewable Fuels Standard. A separate lawsuit filed in State court by **POET** challenges the LCFS regulation primarily on procedural grounds.

ARB Spokesman Stanley Young pointed out that corn ethanol producers are ranked for carbon intensity according to a variety of factors, including the energy-intensity of their biorefineries. While all carry the 30 gram indirect-impact value, including any corn ethanol producers that locate in California, ARB estimates direct-impact carbon values using a standard life cycle analysis method that considers the inputs, processes, energy sources and other factors at particular types of biorefineries.

“Seven of the 11 original [ARB] ethanol pathways came in under gasoline,” said Young. “Some Midwest corn ethanol came in at about the same carbon intensity as gasoline, while a few that are dependent on coal-fired power came in higher than gasoline.”

Biofuel and alternative fuel producers have the option of submitting for ARB approval a custom pathway for particular

products, production processes, or refineries, either by modifying an existing ARB pathway or developing one for a new fuel or production process.

At CCBJ’s deadline, ARB was holding hearings on the adoption of dozens of new biofuel pathways, including eight corn ethanol pathways proposed by **Archer Daniels Midland** that “describe a new, very efficient plant using varying combinations of natural gas, coal, and biomass for process fuel,” according to the staff report. Eleven pathways proposed by **POET** include some that would use lower-energy raw starch hydrolysis in place of high-temperature initial cooking.

Other U.S. ethanol producers and one Caribbean Basin processor of Brazilian sugarcane ethanol proposed new pathways, and ARB staff proposed three new internally developed pathways: two for used cooking oil biodiesel and one for corn oil biodiesel extracted from ethanol byproducts.

Simon Mui, a **Natural Resources Defense Council** scientist who sits on the ARB’s LCFS Advisory Panel, credits the LCFS with inspiring biofuel producers to get very creative about efficiency. “You now have ethanol facilities figuring out how to scavenge and reuse waste heat, using biomass or landfill gas to displace some of their coal power, using more specialized and efficient enzymes to convert the starch to sugar, and new fermentation methods to convert sugar to ethanol,” he said.

ARB also convened an Expert Workgroup to review its methodology for calculating land use impacts, according to Mui, who expects the value to be adjusted based on the latest modeling updates and recommendations from the working group. The working group evaluated updates to ARB’s analysis that would result in between 15 to 21 gram “penalty” for land use impacts versus a 30 gram/MJ penalty. As in other regulations, ARB will continue to review and account for the

latest science in updating its emission factors, according to Mui.

ARB Criticized For Reliance on Cellulosic Ethanol

However, it is advanced biofuels—cellulosic ethanol from agricultural waste and municipal solid waste, biodiesel from algae and other emerging technologies—that ARB hopes will do the real heavy lifting as the LCFS targets ramp up in the second half of the decade. These projections are based largely on the work of the late Alex Farrell from UC Berkeley and Daniel Sperling of UC Davis.

Farrell and Sperling ranked various types of advanced biofuels for carbon intensity, finding among other things that cellulosic ethanol from municipal solid waste would be one of the top clean fuels under a LCFS. For their lifecycle analyses, the authors considered a wide range of factors, including the avoided methane emissions as MSW is diverted from landfills.

But as any follower of advanced biofuels knows, technology developers are notoriously optimistic about how soon they'll be able to commercialize advanced biomass conversion technologies. On this score, the API and energy research firm **Charles River Associates** have criticized ARB for relying too much on near-term commercialization of advanced biofuels.

They note that advanced biofuel suppliers are already falling short in producing the amounts mandated for fuel blends under the federal Renewable Fuels Standard. "That industry is working very hard toward ramping up production but to date we haven't seen it," said Patrick Kelly, senior policy adviser for the API.

Charles River Associates Principal Paul Bernstein points to the additional complication of the "blend wall"—the fact that engines in many vehicles on the road weren't designed to run on blends of more than 10% ethanol. The EPA recently au-

thorized E15 (15% ethanol) for light-duty vehicles manufactured after 2001, but still the lack of retail fueling infrastructure "becomes a barrier to entry," and complicates LCFS compliance for fuel suppliers, according to Bernstein.

As noted in CCBJ's June 2010 transportation edition, many advanced biofuels developers are seeking to produce so-called "drop-in" fuels that essentially mimic gasoline, diesel and other fuels and thus don't require a separate fueling infrastructure or engine modifications. But as CRA's study notes, "gasoline or diesel substitutes from BTL [biomass to liquids] processes, should they become available ... are likely to become available on a timetable much like that of fleet turnover."

Mike Waugh, chief of the criteria pollutants branch at ARB, underscored that the LCFS only requires modest reductions in carbon intensity in the first years: 0.25% in 2011, 0.5% in 2012, 1% in 2013 and 1.5% in 2014. To meet these early targets, ARB is confident currently available biofuels produced on lower-carbon pathways will suffice.

As targets increase in the second half

of the decade—rising by 1.5% annually from 2015 to 2019 and by 2% in 2020 to reach the 10% goal—ARB will review the commercial availability of advanced biofuels and may adjust the targets, if necessary, to reflect fuel availability.

"An advisory panel with 40 members from academia, oil companies, consultants and stakeholder representatives will conduct a formal review for the board by the end of 2011 and a second one by the end of 2014," said Waugh. If qualifying biofuels prove to be scarce when the targets begin ramping up at a faster pace mid-decade, ARB staff, with the assistance of the advisory panel, would probably flag this as an issue, initiate a review, and bring proposed revisions before the board. "We're hoping these really ultra-low carbon biofuels come along, but there is an opportunity to recommend modifications if this proves not to be the case," said Waugh.

LCFS Credit Trading System Likely to Be Copied in Other States

As things stand now, if low-carbon advanced biofuels are not available in enough quantity by, say, 2015, fuel sup-

New Biofuels Pathways Under Consideration by ARB

- Eight new Midwest corn ethanol pathways proposed by Archer Daniels Midland describe a new very efficient plant using varying combinations of natural gas, coal, and biomass for process fuel.
- 11 new Midwest corn ethanol pathways proposed by POET, lower-energy raw starch hydrolysis process to replace the conventional cooking process, natural gas or biogas for process power, combined heat and power and corn fractionation.
- Three new pathways for hydrous Brazilian sugarcane ethanol dehydrated in the Caribbean basin under the terms of the Caribbean Basin Initiative.
- Three new pathways for modern natural-gas-powered Midwestern dry mill corn ethanol plants. (Submitted by Green Plains Holdings, Lakota and Central City; and Louis Dreyfus Commodities.)
- Three internal, staff-developed pathways include:
 - Two Midwestern used cooking oil biodiesel pathways: 1) higher-energy rendering process requiring "cooking" and 2) lower-energy "non-cooking" rendering process.
 - One Midwestern corn oil biodiesel pathway in which corn oil is extracted from DGS co-products at the end of the corn ethanol production process.

pliers will have little alternative but to comply by using credits earned in the early years of the program or purchasing credits from others, including suppliers of alternative fuels that ARB has determined meet the 2020 carbon-intensity targets: electricity; hydrogen and hydrogen blends; fossil compressed natural gas (CNG) derived from North American sources; biogas CNG from sources like landfills; and biogas liquefied natural gas (LNG).

Under the LCFS credit system, gasoline and diesel suppliers who find themselves unable to economically comply through blending of conventional and advanced low-carbon biofuels would pay for credits in an open market. A major source of these credits would be unregulated alternative fuel suppliers—including electric and gas utilities—that sell electricity, natural gas or other low-carbon fuels to California drivers.

Electric utilities, like refineries, are subject to GHG reduction requirements for their facilities in California, as well as meeting 33% renewable generation requirements by 2020. But even with today's California power mix, electricity, unlike gasoline and diesel, already meets the 2020 LCFS standards due to the inherent efficiency of electric powertrains. So utilities providing transportation electricity are not required to report under the LCFS. They'd have to opt-in to the program, agree to become regulated parties, submit quarterly and annual reports documenting their electricity and natural gas sales to California drivers and agree to be audited by ARB for verification. (After 2015, electricity suppliers will have to install separate meters in residences to verify sales.)

Landfill gas compressed for vehicle usage is one of the most favorable fuels under the LCFS, with a carbon intensity of just 11.26 grams/MJ. As described in CCBJ's Oct/Nov edition, landfill operators are increasingly converting landfill gas to CNG or LNG and replacing their

diesel collection trucks with natural gas vehicles. According to a presentation at the March 2011 Environmental Industry Summit by Chuck White, director of regulatory affairs at \$12-billion **Waste Management**, the largest operator of landfill gas to energy projects in the United States, WM is investigating new revenue models under the LCFS. Of WM's 3,000 trucks in California, 800 are now CNG/LNG but 2,200 are still diesel. At the Altamont Landfill a \$15 million capital project now results in 13,000 bio-LNG per day at 5% the carbon intensity of diesel. The 5 million gallons per year equates to 33,300 MTCO₂e/yr LCFS GHG credits or \$1 million at \$30/MTCO₂.

Unlike carbon credit markets established by the European Union Emissions Trading Scheme and California's own cap-and-trade system (coming into force in 2012), the utilities and other opt-in alternative fuel suppliers selling credits will not have to achieve any reduction in carbon emissions below a baseline because their fuels are inherently low carbon. The logic is that by displacing high-carbon gasoline and diesel with low-carbon electricity and other fuels there will be a net reduction in transport-related GHGs in the state.

According to Waugh, some commenters have advocated that some of the credit revenues from transportation electricity sales be returned to electric vehicle owners in the form of lower electricity rates or reduced cost for recharging and metering hardware. Waugh says an electricity workgroup is discussing the generation and disposition of credits from electric vehicles and no firm decisions have been reached.

As might be expected, gasoline and diesel providers are not thrilled about the prospect of paying competing fuel providers to meet their requirements under the LCFS. The oil industry's concerns are amplified by the fact, in the tradition of

Electric Car Share of New Vehicle Sales in the USA

2009	0%
2021	12%
2030	20%

Source: CCBJ's Future of Fossil Fuels Survey 2011. Question was: What percentage of the U.S. new car market do you think PHEVs and EVs combined will earn in 2021 and 2030?

California's long history of leadership on environmental standards, California's LCFS model may spread. The 10 Northeastern states in the Regional Greenhouse Gas Initiative, plus Pennsylvania, are collaborating together through North East States for Coordinated Air Use Management (NESCAUM) to develop an LCFS model rule. Other U.S. states as well as Quebec and British Columbia are also considering low carbon fuel standards.

NESCAUM and ARB have formally traded ideas and insights, and it's widely expected that the NESCAUM model rule will be similar to ARB's LCFS. At the end of 2010, the northeastern state energy and environmental officials working through NESCAUM said their model framework would be ready in early 2011, while the required economic analysis would take longer. In its end-of-year memo, the NESCAUM LCFS group promised the draft rule would "include elements common in many regulatory programs, as well as some that are unique to the LCFS program."

Influencing low-carbon policy in other states, nationally and even internationally is clearly a goal of ARB. ARB wants the LCFS to "establish a durable fuel carbon regulatory framework that is capable of being exported to other jurisdictions," according to a staff report. This is in line with what the state's legislature intended—and what 61% of the state's voters essentially ratified in the November 2010 election—when it passed AB32, the Global Warming Solution Act, in 2006: "Placing California at the forefront of national and international efforts to reduce emissions of greenhouse gases." ⚙

Shale Gas Transforms the U.S. Gas Market, Spurs Water Treatment Business

Downstream Strategies, Aqua-Pure Ventures, and Altela offer perspective on treatment and disposal issues facing the shale gas industry.

Mark Ellis, chief economist for **Sempra Energy** called shale gas a “once-in-a-career, once-in-a-generation development in energy markets,” at a Law Seminars International workshop in September 2010. “It has already dramatically transformed the U.S. gas market and it has the potential to transform world gas markets as well.”

Robert Clarke, unconventional gas research manager for energy consulting company **Wood Mackenzie** said recently: “The magnitude of the U.S. Shale gas resource is extraordinary.”

Richard Smead, an upstream and midstream natural gas analyst at **Navigant Consulting**, has called the Marcellus Shale reservoir “Prudhoe Bay under Pittsburgh,” according to Robert Bryce in his book *Power Hungry: The Myths of Green Energy and the Real Fuels of the Future*.

Pick your descriptor or metaphor: shale gas resources are big—and they’re mostly located conveniently near existing conventional gas reserves “so you don’t need to build a massive amount of new long-haul pipelines,” to get the gas to markets, said Ellis. “You still need to build lots of new gathering and processing infrastructure, but those cost a fraction of what a long-haul pipeline would cost.”

Shale gas is produced without the risk associated with exploring for conventional gas reservoirs. Gas producers use horizontal drilling and hydraulic fracturing to produce gas from shale in what is basically a manufacturing process. Along with coal bed methane and tight sands gas, shale gas reserves have vastly increased the estimates of domestic gas supplies.

Current and anticipated reserves have led analysts to project stable gas prices for many years. Electric utilities report that gas suppliers are offering 10- and even 20-year contracts—from an industry that once shunned contracts longer than a year. In 2010, the power industry was already shifting dispatch priorities to natural gas power from coal units. According to Navigant Consulting’s February 2011 *Natural Gas Notes*, electric generation demanded almost 9% more gas in the summer of 2010 over the previous summer “as a result of favorable prices compared to coal.”

Truth or Fiction

There’s just one little problem: a growing anti-fracking movement that accuses the industry of causing earthquakes, ruining cherished vistas and streams with endless well pads and other infrastructure and—potentially worst of all—contaminating water supplies. The environmental consequences of shale gas production have prompted protests and calls for moratoria in some states like New York, and become the subject of the Oscar-nominated HBO documentary *Gasland*.

The gas industry and many environmental consulting and engineering firms that serve it says *Gasland* got the story wrong. The **American Natural Gas Assn.** (ANGA) cites EPA and state regulatory reports to debunk some of the most inflammatory charges in the film—including one scene in which a fire erupts from methane leaking from a household water fixture. According to ANGA, the Colorado Regulatory Commission issued a “rare public rebuttal” to the film, citing the presence of methane in wells prior to natural gas drilling.

The truth, as usual, is somewhere in the middle. “There are a lot of claims out there and I don’t believe all of them are true, yet I think there are some serious impacts,” said Evan Hansen, president of environmental consulting firm **Downstream Strategies** (Morgantown, WV).

Vendors respond to environmental hazards posed by shale gas production

U.S. shale gas resources are huge and will contribute to stable gas prices for many years, but the fracturing process used in shale gas production has serious environmental consequences. Groundwater contamination poses the worst-case risk. Large water equipment suppliers like Siemens, GE and Veolia are developing solutions, along with many smaller, independent players.

Above ground, drilling pads are typically built in dense networks with as little as 500 feet of separation to “create an interconnected fracture network in the shale,” said Mark Zoback, professor of earth sciences and geophysics at Stanford University and co-founder of consulting and software firm **GeoMechanics** (Menlo Park, Calif.), another presenter at the September 2010 LSI seminar. “The footprint of drilling operations can be messy, so it’s beneficial if operators can drill multiple wells from each site. But it’s certainly a big impact.”

In mountainous West Virginia, which sits atop the vast Marcellus Shale formation, Hansen says drilling operators need to do a better job with erosion control. “There’s no debate that there’s erosion and sedimentation into surface waters from building drilling pads on the steep terrain in West Virginia,” he said.

The biggest concern for residents of shale gas regions—and the most potent challenge and potential liability for gas producers—is water contamination. *Power Hungry* author Bryce, a big natural gas fan whose “real fuels of the future” are natural gas and nuclear, notes that “properly fracturing a shale gas well requires the use of 1 to 3 million gallons of water. To obtain optimum results, oil-field service companies add various constituents to the water, including... surfactants, antibacterial agents, and friction reducers.”

“Regulation of the fracturing process is generally left to the states—and some states that are seeing big increases in gas drilling are under pressure from environmental groups to ramp up regulation,” wrote Bryce.

This is certainly a concern in West Virginia. “Our state Department of Environmental Protection has 17 inspectors to monitor more than 55,000 wells,” said Hansen. “There are two bills before the West Virginia legislature now to better regulate the Marcellus industry.” Permit and reclamation fees would be used to fund better oversight, according to Hansen.

Finding Ways to Reduce the Risk of Groundwater Contamination

Shale gas drilling and hydraulic fracturing can contaminate groundwater through two mechanisms: improperly constructed and cemented wellbores and inadequate treatment or disposal of water produced from fracking.

“The Marcellus wells are thousands of feet deep, well below the drinking water aquifers,” said Hansen. “But when they drill down, they need to line the hole and grout around it with something like cement to make it impossible for the fracking water to seep into the aquifers. If the grouting is not done properly, there might be pathways where the polluted water could get directly into the aquifers.”

Zoback points out that importance of properly cementing wellbores is underscored by the Macondo oil spill in the Gulf of Mexico. “This is definitely an issue the industry is familiar with,” he said. “The problem is not hydraulic fracturing. The problem is well construction.”

Managing the water used in fracking is an entirely different problem. “After you inject the water and make the hydrofractures, you allow water to flow back so the gas can flow,” said Zoback. Not only does this water contain the surfactants and

other chemicals but it also brings up high concentrations of iron, selenium, arsenic and other chemicals exuded from the shale, according to Zoback.

Zoback and his colleagues are researching the use of highly compressed CO₂ as a fracturing fluid, which would be absorbed into the shale—providing long-term sequestration—and avoid the water disposal and treatment challenges.

The Environmental Protection Agency (EPA) announced in March 2010 that it would conduct a study of hydraulic fracturing to characterize potential impacts on groundwater. After public meeting attended by thousands of concerned citizens and industry supporters in February 2011, the agency submitted its draft study plan to the EPA’s independent Science Advisory Board. After final revision with SAB input the study will commence; initial findings and results are expected by the end of 2012, according to *BNA Environment Daily*.

Companies Seek Better Options for Frack Water Treatment

In the meantime, the water treatment and disposal business is booming in Gasland. “Industrial problems mean markets, and there may be no opportunity more talked about in today’s water treatment market than solving the problem of disposing of the enormous volumes of wastewater generated by [hydraulic fracturing],” wrote George Stubbs, senior editor of CCBJ’s sister publication *Environmental Business Journal*. Typically “frack water” is “trucked off site for disposal at great expense. Oil and gas companies are looking for cheaper and more environmentally sensitive options, and companies are lining up to serve them.”

EBJ’s annual snapshot survey of more than 300 environmental companies conducted in January and February 2011 ranked “Shale gas exploration and production” as the single most promising market for growth in 2011-2013.

Large suppliers of water treatment equipment such as Siemens, GE and Veolia are active, as are many smaller players. Here’s a look at two independent water treatment technology firms, their activities and their perspective on this growing market.

Aqua-Pure Ventures Markets Mobile Evaporator for Flowback Water

In 2004, Calgary-based Aqua-Pure Ventures entered the Barnett Shale market after acquiring Fort Worth-based Fountain Quail Water Management. Aqua-Pure’s NOMAD mobile evaporator treats the flowback water from hydrological fracturing after the water is run through a clarifier to remove solids, leaving a salty water for treatment.

The two products of this process are pure, distilled water, which can be reused at another well, and a concentrated brine that can be used as a “kill fluid” to contain gas pressure under certain exploration circumstances. The process can recycle 70 to 85 barrels of every 100 barrels of wastewater handled, according to Aqua-Pure CEO Brent Halldorson.

Despite the availability of low-cost disposal options in the Barnett Shale—essentially, shallow wells with limited effectiveness—Fountain Quail was able to strike a relationship with Devon Energy, which was dedicated to water recycling. But the technology required a lot of fine-tuning: It took about six months to treat the first 30,000 gallons of water. “Now, we do that in a day,” said Halldorson.

Just as the Texas Railroad Commission was beginning to scrutinize more closely the practice of wastewater disposal in existing wells, the more viable water-bearing Ellenburger Formation was discovered underneath the Barnett Shale formation.

“All that meant was, disposal got cheap and abundant overnight,” Halldorson recalls. “That was a disaster for us.” The company considered moving to other

shale plays—the Piceance Basin in Colorado was an option, but difficult to work in, while Marcellus was only starting to be discussed—but “we decided to get efficient in Texas and drive our costs down.” **GE Water & Process Technologies** and others came to the Barnett, but “we were more efficient.”

Profitability remained elusive as the company refined its technology, and the recession hammered revenues. Financial reports show a net loss of \$4.3 million on revenue of \$2.3 million for the first half of 2010, compared with a net loss of \$1.6 million on revenue of \$8.2 million for the comparable period of 2009.

What Aqua-Pure sees as allowing it to turn the corner is the application of its technology in the now vibrant Marcellus Shale region in the Northeast, where recycling is more economically viable. The standard practice is to truck wastewater to Ohio at \$5 to \$12 per barrel.

In Pennsylvania, Fountain Quail is teaming with **Eureka Resources** and includes Range Resources, Chesapeake Energy, Southwestern Energy, and XTO Energy among its customers. It has three NOMAD units located in Williamsport, providing a combined feedwater capacity of 7,500 barrels per day (bpd). The company is planning to move a fourth unit up to Williamsport, for 10,000 bpd.

The GEs and Aquatechs of the world are taking aim at the Marcellus Shale as well, but Halldorson believes his firm has the advantage of flexibility. A GE likes to build large, centralized plants, which doesn't match up well to the dynamism of gas exploration in today's world, as veterans of the oil patch can appreciate, according to Halldorson.

Gas today is very cheap, and “gas producers are running in punching holes just to hold leases,” he says. Service providers thus have to be very nimble. “Let's say we need 100,000 barrels per day capacity next year; we'll build a fixed evaporation plant,”

he explains. “But if we find that we need to be in New York, we can pick up the NOMADs and move them there.”

Halldorson went on to explain that there are two schools of thought on wastewater management in the Marcellus Shale. “Producers like on-site disposal; it costs a lot of money to move water around. And if you're doing it on site, they want it basic, cheap, simple.”

To meet more rigorous disposal requirements—as the Pennsylvania Department of Environmental Protection (DEP) is pushing—producers will still want an alternative to trucking to Ohio, and that's where centralized plants come into play, according to Halldorson. “DEP is saying, ‘we'd much rather have eight to ten centralized plants that we can keep an eye on.’”

Evaporation “is more expensive than producers like to pay for on site,” he continues. For on site operations, Fountain Quail performs very basic treatment, or pre-treatment, to clean the water up to the level for reuse.”

Fountain Quail is planning to pursue other shale gas opportunities, and each has its own economic justification for wastewater recovery. The Fayetteville Shale formation in Arkansas, for example, has lots of fresh water, and the gas producers don't want it back, so it needs to meet state standards for discharge into streams.

By comparison, for the Eagle Ford formation south of San Antonio there isn't enough freshwater to sustain the exploration activities, so water recycling is a must. San Antonio's water supply is the Edwards Aquifer, and “they have real concerns about having enough water to feed the area today,” says Halldorson.

As efficient as Fountain Quail is in its operations, the company is still looking for partnerships to pursue the available market. “We're competing with several of

the very largest companies in the world, like GE and Siemens,” Halldorson says. “As a small company, even though we have an excellent reputation, we're capital constrained and somewhat business development constrained.”

The company has signed a memorandum of understanding with Schlumberger to jointly market their services, and “we're looking at several different kinds of relationships, including construction companies, even entities that can get us into Europe or expand in Canada. What we're

Ranking of Environmental Industry Client Sectors by Prospects for Growth in 2011-2013

Shale gas exploration and production
Renewable energy development
Petroleum extraction & refining
Mining
Power utilities
Primary metals
Chemical
Electronics/computer manufacturing
Solid waste utilities & companies
Water utilities
Transportation mfg (auto & aero)
Major retailers
Metals fabricating/coating
Banks & Law Firms
Consumer products
Federal government: DOD
Petroleum retail/gas stations
Other manufacturing
Federal government: DOE
Federal government: EPA
Property developers: commercial
Federal government: Other
Property developers: residential
Pulp & paper
State government
Local government

Source: *Environmental Business Journal 2011 Snapshot Survey of 324 executives*; Question was: Please rate the following customer areas in terms of prospects for sales growth in the next two to three years. Responses are consolidated from the following options: Very Strong, Strong, Slow Growth, Flat, Modest Decline, Big Decline

looking for is help in business development, financial strength, and the ability to ramp up our equipment.

Altela in the Field With Low-Energy Units for Produced Water Treatment

Developers of desalination technology—salt is a major component of produced water—are hot on the trail of this new market. “The real potential game changer in the desalination industry is the potential in the produced water market,” says Tom Pankratz, editor of the **Water Desalination Report** (Houston, TX). “The market has a very big potential, because the water quality is so terrible.”

Even Richard Heckmann—the same Richard Heckmann who built the US-Filter empire about a decade ago before selling out to Siemens—is back in the water business, aiming his cash directly at the produced water treatment market. Operating more on a transport/disposal model than a treatment model, Heckmann Corp.’s (Palm Desert, Calif.) latest move (as of early November) has been to acquire Complete Vacuum and Rental Inc. (CVR) to complement Heckmann’s 50-mile pipeline in the Haynesville Shale region of Texas with the water-handling needs of the region’s oil and gas operators.

Ned Godshall, co-founder and CEO of **Altela, Inc.** (Albuquerque, NM), believes his firm offers an economic advantage not only to the transport/disposal solution but also to other forms of treatment. Godshall isn’t making his claims based on bench-scale test results either; commercial units of the AltelaRain desalination system are currently operating in the Marcellus Shale formation straddling New York and Pennsylvania.

The AltelaRain system is treatment solution, mobile or stationary as needed, with clear advantages over off-site disposal, which in the Marcellus Shale region means trucking produced water to Ohio. “Our proposition is to eliminate 8 or 9

out of every 10 of those trucks,” Godshall declares.

In terms of market size, Godshall says government studies estimate 18 billion barrels of produced water will require disposal in the United States as available fossil fuel resources are exploited. “It’s a billion dollar problem at least in the Marcellus Shale,” he said. “That’s why there is so much talk about it right now. The only thing that could stop Marcellus gas from being a very good energy solution is this water problem. So that’s why we feel we are at the right place at the right time to help solve that problem.”

Altela’s value proposition compared with other treatment alternatives is based on the fact that those alternatives—membrane technologies like reverse osmosis, or thermal distillation technologies, or variants on those themes—require pressure to operate. That means high capital and operating costs for the expensive metals needed to build pressure vessels that can resist corrosion, and for the electric power required to drive the pressure pumps.

Godshall and his colleagues at Altela like to describe their system as mimicking nature—specifically, the evaporation/condensation process involved in the hydrological cycle. The AltelaRain system consists of towers made of inexpensive plastic, like that used in the signs dotting lawns prior to elections. The wastewater evaporates on the outside of these plastic towers. Low-grade heat in the form of steam from a natural gas or waste heat source creates a temperature difference on the top and bottom of these plastic sheets to effect condensation.

“We can make the towers pretty much any size,” says Godshall. “Picture them as a little taller than your normal water heater, with the same footprint.” The water produced by the process can be returned to the gas operation for the next “frac” job in place of water from the local utility, thereby complementing the savings

from reduced off-site disposal as part of the value proposition.

Godshall, who has undertaken a series of startups since leaving Sandia National Laboratory in 1994, and water rights lawyer Matthew Bruff launched Altela with their own funds in 2005, licensing the AtelaRain technology from a professor at Arizona State University. New Mexico-based venture capital firm Verge Fund led a \$1.2 million round of investment in 2006, and Altela raised another \$7.1 million in Series A funding in late 2007. When Godshall spoke with EBJ in mid-November, the company had just completed a Series B round of financing with an undisclosed investor group.

Prototypes of the AltelaRain system were tested in New Mexico, with the help of state grants, and in the Piceance Basin in Colorado. Cold-weather tests were also successfully conducted in Canada, north of Edmonton, according to Godshall.

The company is now selling commercial units in the Marcellus Shale region. “We can basically clean up any kind of contaminated water, but we’ve chosen to target the oil and gas industry, because they have the most-contaminated brackish water, and they pay the most now to ship the water,” says Godshall.

He doesn’t disclose annual revenue. “You can certainly say that our revenues are compounding greatly, year over year.” As for profitability, “our pro forma is picturing crossover into profitability in the first quarter of 2012.”

Where does Altela expect to be in five years? “We’ll be a much bigger company, but I expect we’ll be acquired,” says Godshall. “If you look at good water companies with novel ideas, they tend to get snatched up by one of the three big water companies in the world—GE, Siemens, or Veolia.” In the meantime, “we’re the only company out there in Pennsylvania treating water at a well site. The others aren’t doing it, because it’s too expensive.” ☀

Generators Review Cleaner Pathways to Electricity, But Regulatory Uncertainty Constrains Investment

Time is ripe for natural gas, thanks to price, efficiency, and anticipated GHG constraints; some utilities will retire and others optimize their coal-fired plants.

While the November 2010 election has sidelined federal climate legislation for at least two years, electric power utilities and their consultants still incorporate the possibility of cap and trade legislation in their planning scenarios and investment decisions. Experiences with the Clean Air Act and other federal and state environmental laws provide ample evidence that the priorities of legislative majorities and executive branch agencies can shift significantly from term to term, and that court decisions can change the intensity and pacing of regulatory requirements.

"We still evaluate greenhouse gases as part of our resource planning analyses for utilities, but at this point it's more of a sensitivity analysis," said Block Andrews, director of strategic environmental solutions for consulting engineering firm **Burns & McDonnell**. "Greenhouse gases have not gone away, but federal legislation appears considerably less imminent than what we saw a year or two ago."

As discussed in CCBJ's December 2010 North American Climate Policy edition, the implications of EPA's GHG permitting regulations are still unfolding. While the best available control technology (BACT) guidance stops short of requiring fuel switching or carbon capture on new or significantly modified coal power plants, it focused on combustion efficiency. But the future of that permitting regime is in question as Congressional Republicans take aim at EPA's authority and funding. At the same time, EPA's other rulemakings for air, water and waste

laws will likely put a large number of older coal-fired power plants and gas/oil steam plants in the economic cross-hairs.

According to Metin Celebi, an energy consultant with **The Brattle Group**, utilities must consider a wide range of pending and potential regulatory scenarios, taking into account different compliance timetables. "They need to consider different credible future scenarios for environmental regulations and see how the strategies they have in mind survive in each of those," said Celebi. "Not all these regulations have the same level of uncertainty or flexibility. For example, GHG regulations probably face the biggest pushback from legislators and from the industry. So even if the requirements are very strong there could be practical barriers such as litigation of the regulations and reducing funding for EPA."

EPA's Maximum Achievable Control Technology (MACT) rulemaking for mercury, acid gas and other hazardous pollutants, which will likely require many coal plant operators to install expensive air pollution control systems, is on a more rigid timetable, according to Celebi. "It is already set in motion. EPA is obligated under a consent decree signed in 2009 to finalize these regulations by the end of 2011.... There are some flexibilities with respect to compliance periods and necessary control equipment but they're not as flexible as some other emerging regulations," said Celebi. "Compliance with the utility MACT could be required as early as 2015 or 2016."

Andrews says he expects the MACT rule to clarify what air quality standards coal-fired plants will have to meet, removing some of the uncertainty around questions such as whether to install dry sorbent injection, a wet scrubber or a dry scrubber. However, there will still be ambiguity about future requirements—including those driven by lawsuits, court settlements, potential changes in ambient air quality standards and other factors.

Major investment required by utilities

EPA's GHG regulations are still uncertain, but EPA's MACT regulations are slated to be finalized by end of 2011, clarifying air quality standards for coal plants. Some utilities will opt for more natural gas rather than upgrade coal-fired units. Others will find ways to reduce GHGs from existing plants -- from streamlining maintenance, to recovering waste heat and improving combustion processes. Fearing stranded assets, power utilities are reluctant to invest in solutions that could get outmoded by future regulations. Thus, regulatory uncertainty puts the brakes on investment once again.

Particularly uncertain, according to Andrews and many in the electric power business, is New Source Review (NSR) oversight that sometimes kicks in when utilities upgrade coal power plants beyond a difficult-to-define threshold.

In an October 2010 article, Burns & McDonnell's Robynn Andracssek, associate environmental engineer, characterized NSR as "arguably the most confusing, politically charged and ambiguous aspect of the Clean Air Act, and possibly the program with the largest non-compliance monetary implications. Not only has there been an endless series of proposed changes, but EPA has changed its interpretation of regulations (often to align with the most current administration)."

Andrews says utilities fear ending up with stranded assets if they invest now to comply with current and expected rules only to find future regulations—perhaps driven by a court decision—putting their units out of compliance. "You may have built an expensive air pollution control device then end up with a stranded asset five years from now because your existing controls will not meet a future compliance requirement such as an NSR settlement or ambient air quality standard... This is largely why you're not seeing a boom in people putting on pollution controls."

Andracsek writes that “Industry is craving guidance and certainty in regulatory compliance.” She urged EPA to “update the NSR manual to incorporate the patchwork of memos and court decisions which have revised NSR implementation.” Andrews argues for Congress to amend the Clean Air Act to provide “reasonable, practical direction instead of punting to EPA to develop regulations which we know will get challenged in the courts.”

Shift from Coal to Gas: Progress Energy Replaces Units

Legislation to clarify air quality rules is distinctly unlikely in the current Congress, and maybe in any Congress, so the electric power industry will probably contend with such uncertainties for a long time.

One thing that is clear is that in addition to EPA’s air-water-waste regulations and GHG permitting regime, another factor driving decarbonization of electrons is the abundance of inexpensive natural gas on the market. This has driven utilities to dispatch existing gas resources (their own and those of independent power producers) more readily and to look more favorably on investing in new gas power capacity. (See *Shale Gas*, p.X.)

According to **Navigant Consulting** (citing Energy Information Agency data), electric generation demand for gas increased in the summer of 2010 by 9% over 2009—from an average of 20.9 billion cubic feet per day (Bcf) to 22.6 billion. The causes: “favorable prices compared to coal, and a very hot summer.”

Emblematic of the shift from coal to gas is Progress Energy, which decided in late 2009 and early 2010 to retire 11 coal-power units at four plant locations, representing 1,500 MW of capacity and replace them with 1,550 MW of new combined cycle natural gas plants. “GHG emissions and future regulation of carbon by either the EPA or Congress definitely played a role in our decision to retire these units and switch to natural gas, however

GHGs were not the sole deciding factor,” said Scott Sutton, spokesman for the integrated utility with 22,000 MW of generation and 3.1 million customers in the Carolinas and Florida.

“We looked at the range of all the upcoming environmental regulations including mercury, criteria pollutants and the potential for coal ash regulation as well as carbon regulation,” said Sutton. “We factored in how much money would be needed to retrofit those older smaller plants with the technology to meet the new standards versus how much it would cost to build new gas-fired facilities.”

“At the end, it was clear that for these units, many of which are 50 years old and less than 400 MW each, the best strategy for us as a company was to get ahead of carbon regulations and other environmental regulations,” said Sutton. “We’ve broken ground on one of our natural gas plants already, and we’re breaking ground in March 2011 on the second one.”

Progress is building new natural gas capacity at a good time from the technology standpoint as well as the fuel price perspective. Siemens, GE, Mitsubishi, Alstom and other turbine manufacturers have pushed the efficiency envelope and are now offering gas turbines that can achieve close to 40% efficiency (the percentage of total energy in the fuel which is converted to electricity) in simple cycle operation and close to 60% in combined cycle setups (that use exhaust energy to power a steam turbine). Getting more power for Btu consumed means lower-carbon emissions per MWh generated.

“Back in the 70s and 80s, gas turbine efficiencies were around 30 percent,” said Vinod Philip, director of gas turbine engineering for **Siemens Energy**. “Today we are in excess of 38 percent in simple cycle, and close to 60 percent in combined cycle operation, with the Department of Energy challenging us to reach 65 percent in the future.”

By building new natural gas capacity, Sutton says Progress will avoid the reliability challenges that North American Electric Reliability Council, Charles River Associates, Brattle and others have warned could face some utilities as older coal units are forced into retirement because their owners can’t justify the pollution controls and other retrofits needed to meet tightening regulations.

Some environmental groups advocated that Progress, which had 2009 revenues of \$9.9 billion, opt to build more wind and solar power. According to Sutton, the company engaged in dialogue with such stakeholders about the need for reliability in an electric grid, which natural gas power plants could provide while intermittent wind and solar resources could not.

Progress has added about 100 MW of solar, hydroelectric and wood waste biomass power since 2007, when North Carolina adopted a 12.5% by 2020 renewable energy standard (with carve-outs for solar and livestock waste biomass power). The company has also tested co-firing biodiesel with oil and biomass with coal.

A project with North Carolina State University to use torrefied wood—a heating process that yields chips with higher heating value produced with the university’s Autothermic Transportable Torrefaction Machine—hasn’t moved forward yet because Progress and its partners haven’t been able to stockpile an adequate supply for a full-scale trial in the 316 MW Cape Fear coal unit, according to Sutton.

The company considered a broader co-firing initiative or even repowering some coal units for biomass combustion before deciding on its natural gas new-build program. “We were looking at not only the cost of upgrading the equipment to be able to handle biomass as well as the environmental controls that would have still been needed for these units,” said Sutton. “In the future we could bring them out of retirement [for co-firing or conversion to

all-biomass], but we definitely don't have any plans on the table to do co-firing on an ongoing basis."

Optimizing Coal Plants: Three Ways

For owners of coal power assets that have sufficient remaining operational life expectancy to justify investments, there are optimization strategies that can improve efficiency and reduce carbon emissions per MWh. Some of these have operational benefits as well that can improve a plant's ROI.

"There are three major areas and within each area a lot of specific things you can do," said Revis James, who heads generation planning research for the **Electric Power Research Institute (EPRI)**. "Number one is streamlining maintenance so you reduce unexpected outages and reduce the duration of planned outages. When you start up and shut down, you're not operating at the optimum heat rate."

The second type of improvement focuses on recovering more waste heat. "You can increase efficiency by doing that through various physical modification and operating strategies," said James.

According to Megan Parsons, a development engineer for Burns & McDonnell, some high efficiency technologies deployed on coal plants in Europe and Japan—where coal costs and electricity prices are significantly higher—have yet to become cost-effective in the United States; but that may change going forward: "In the future, small Btu gains will be important in the United States," said Parsons.

"Gas to gas heat exchangers, for example, can be used to recover heat from flue gas. However as you take that heat out of the flue gas you start to condense sulfur and other chemicals on the heat exchanger," said Parsons. "So you have to use expensive corrosion resistant metals on your heat exchanger, and that's not cost effective based on today's U.S. value of

No Single Fuel or Technology of Choice in the Power Sector

The abundance of new natural gas will increase the share of natural gas-fired generation in the North American power sector. It will expand the role of natural gas-fired generation technologies to back up renewable power resources—a new role for natural gas.

Natural gas-fired generation consumed 3 Bcf per day more natural gas in 2009 than in 2008 when adjusted for the impact of the Great Recession. Displacement of coal-fired generation contributed significantly to this number. But there is a limited pool of "spare" gas-fired capacity that prevents wholesale displacement of coal with natural gas. In addition to this fuel switching, the power sector can reduce near-term CO₂ emissions by replacing existing coal-fired plants with new gas-fired plants and converting existing coal-fired plants to burning gas. This would require substantial investment and would result in growth of natural gas use. But power companies would be concerned about longer-term requirements to further reduce CO₂, which would also affect gas-fired facilities.

The power industry has a multiple-decade planning horizon. If the goals include cutting carbon emissions substantially over the long term, such as the often-cited 80 percent reduction by midcentury, aggressive development and deployment of zero-carbon technologies, including nuclear and CCS, will need to take place today. But a gas-based solution, on its own, does not provide a long-term path to a low-carbon future. To get there will require a portfolio of options including not only natural gas but also some mix of nuclear power, renewables, and breakthroughs in CCS.

Source: IHS Cambridge Energy Research Associates; Fueling North America's Energy Future: The Unconventional Natural Gas Revolution and the Carbon Agenda

coal and energy pricing. Will that still be true in 10 years? Maybe not, and maybe we'll put on flue gas heat exchangers."

Improving combustion processes are the third category of coal plant optimizations, according to James. "Within limits, you can optimize the way you operate the boiler. A lot of work has been done looking at how we can get better at burning coal. EPRI has done work over the years modeling what goes on in the boiler and how to modify it for improved combustion," said James. (As noted in the AEP profile on p.X, generators often forego some boiler optimizations to improve efficiency because the upgrades could also trigger NSR.)

Reducing emissions per MWh can also allow a coal plant operator to reduce its investment for air pollution control systems, according to James. "There's no way someone is going to improve efficiency to the point where they could avoid having

to put in scrubbers, but they might be able to mitigate cost and the sophistication of the emissions controls they'd have to put in place."

Pre-Treating Low-Rank Coal

Some energy researchers and power companies are experimenting with pre-treating coal for greater combustion efficiency. For example, with support from the Department of Energy and technical assistance from Lehigh University's Energy Research Center, **Great River Energy (GRE)** has funded and developed DryFining a low-temperature coal drying process that is being tested at its Coal Creek power station in North Dakota.

The technology is aimed primarily at low-rank lignite with high moisture content that requires energy to evaporate during combustion, according to Nenad Sarunac, associate director of Lehigh's Energy Research Center. "When you look

at coal on a world basis, more than half of it is low rank with moisture content between 30% and 60%," Sarunac said. "German lignite is 60% moisture, Australian is higher. With these types of coal, it makes sense to remove as much moisture as possible before coal is burned."

Like most lignite coal plants, Coal Creek is located at the mine mouth because the moisture in the low-ranked coal makes it too costly to ship long distances, according to Sarunac. The drying process is done in an onsite circulating fluidized bed system using waste heat from the power plant. Thirteen years in development, DryFining is working well, according to Sarunac. "Flue gas flow rate goes down, fan power goes down and you're processing less coal in your [pulverization] mills to obtain the equivalent amount of energy," he told CCBJ. "Great River originally needed eight mills, now they only need six."

A major side benefit of the DryFining project at Coal Creek, which won *Power Engineering* magazine's coal-fired project of the year award in 2010, is that by adding a segregation device (patented by GRE) to the fluidized bed, pyrite can be removed, leading to reductions in sulfur and mercury emissions, according to Sarunac. As flue gas volumes decrease, residence time in the air pollution control equipment increases. "That allowed Great River to basically meet scrubbing requirements for SO₂ without installing additional scrubber modules," said Sarunac.

GRE, a cooperative power wholesaler, owns all IP rights to DryFining and has struck a deal with Australian consulting and engineering firm **Worley Parsons** to commercialize the technology. Lehigh University has worked with Worley Parsons on initial studies to apply the technology to subcritical and supercritical pulverized coal plants as well as coal to liquids plants, according to Sarunac. He also acknowledged that other researchers and companies are pursuing the same

goal, notably German energy company **RWE** and Swedish **Vattenfall**.

Clean Coal Projects Underway, But Investment Lacking

EPRI, an independent non-profit organization, and groups like the Coal Utilization Research Council have long been researching and developing technology to increase the efficiency of new coal-fired plants. Along with the Coal Utilization Research Council, EPRI has targeted a goal of achieving 46% efficiency in a coal power plant by 2025—a quantum leap above the most efficient existing plants which operate in the range of 35% to 37%.

Progress has been slow in recent years, in large measure because a lot of U.S. power generating utilities are backing away from new investments in coal power due to environmental and financing challenges, according to James. "Only AEP and a few other utilities that have significant coal fleets continue to make investments," in RD&D. International support for clean coal research is stronger, especially from Australia, which is 85% dependent on coal power, notes James.

Still, there are a handful of new clean coal projects underway, including at least two ultra-supercritical coal power plants: American Electric Power's 630 MW project in Arkansas and a 650 MW facility being developed in Goliad County, Texas.

As described in the AEP profile on page 37, AEP and its EPC contractors **Shaw** and **Babcock and Wilcox** aim to boost efficiency at the Turk plant in Arkansas to 39%, which they say would cut emissions of CO₂ from the 1.02 tons per MWh produced at AEP's typical supercritical coal plant to 0.96 tons. If Turk runs at an 85% capacity factor, that improvement would yield about 275,000 MtCO₂ reductions for the same amount of power.

The Texas project, Coleto Creek Unit

2, is a joint venture of U.K. independent power producer **International Power** and South Texas Electric Cooperative (STEC). EPC is being handled by a partnership Burns & McDonnell, **Zachry Industrial** and **Mitsubishi Power Systems**, and construction is expected to begin before the end of 2011 and the cost is estimated at \$1.4 billion, according to a news release. International Power says it is "looking ahead" to future U.S. climate change policies by designing the plant to be retrofitted with carbon capture systems.

According to Parsons of Burns & McDonnell, the company has performed an analysis for another utility client examining the economic and environmental implications of replacing its existing coal fleet with new ultra-supercritical generation. "There's a cost in going up the ladder from supercritical to ultra-supercritical temperatures and pressures," said Parsons. "Higher alloys, thicker pipes, more metal in your steam turbines. You're trading off higher capital costs for lower fuel costs."

Increasing temperatures to as high as 1130° F also heightens the risks of plant breakdowns. "There are risk factors in pushing materials to their limitations or using new alloys and materials that haven't pushed up to these high limits," said Parsons, noting that European and Japanese power sectors have more experience with ultra-supercritical operation. Increasing steam temperatures and pressures beyond those demonstrated in Europe and Japan requires advanced materials that have not been approved for use in the United States, according to Parsons.

Duke Energy's IGCC Plant Would Be The Third in the United States

Along with ultra-supercritical combustion technology, integrated gasification combined cycle is the other prominent technology option for coal power generators looking to deploy advanced clean coal technology. IGCC makes coal cleaner from the standpoint of criteria air pollut-

ants and GHGs because pollutants and CO₂ can be separated “pre-combustion” from the coal-derived syngas. IGCC is viewed by many in the electric power industry as the most economically efficient technology to pursue for a new coal-based plant that will incorporate carbon capture and storage (CCS).

The evolution of CCS is unfolding slowly in the United States, with stops and starts in DOE funding priorities and major roadblocks thrown up by state regulators. This GHG mitigation strategy, which the Intergovernmental Panel on Climate Change says must be deployed on a wide scale to stabilize the atmosphere, is gaining the most traction in Alberta and China. (See CCS, p.27.)

In the United States, several IGCC projects have been proposed by coal-based utilities with the option of adding CCS later. One of the leading proponents, AEP, has seen two major IGCC projects halted by state utility commissions concerned about the expensive technology’s impact on electric rates. (See AEP, p.37.) **Duke Energy** (Charlotte, NC; 2010 revenues: \$14.3 billion) is the most advanced developer of an IGCC plant in the United States, which if built would become only the third U.S. IGCC plant and one of a few dozen worldwide.

Duke’s experience building its 618 MW IGCC plant in Edwardsport illustrates how difficult and expensive building new IGCC facilities can be. After its initial cost estimate of \$2 billion was approved for cost recovery by the Indiana Utility Regulatory Commission (IURC) in November 2007, Duke petitioned for and received a cost increase to \$2.35 billion in 2008, according to the company’s 2010 annual report.

Then due to “design changes reflected in the final engineering leading to increased scope and complexity,” Duke and its partner **Nucor Steel** requested and received the go ahead to spend up to

\$2.975 billion, with the caveat that about \$200 million of that would be subject to prudence review, that Duke would take a 1.5% reduction in equity return for project costs above \$2.35 billion, forego petitioning for any general rate increases until March 2012 and give up some tax benefits associated with the project.

In December 2010, this agreement unraveled in part because the *Indianapolis Star* newspaper published emails showing questionable communications between the company and a IURC attorney—who later was hired by Duke. “The Office of Utility Consumer Counselor compared it to jury tampering and said the matter remains suspect, even though several people at Duke and the state have been fired or resigned,” wrote the *Star* on February 1, 2011. According to Duke’s annual report, hearings on the matter have been scheduled for March through June 2011. Despite all these cost overruns and turmoil, the project was 80% complete at the end of February 2011, with Duke expecting commercial operation to begin in 2012.

On a related track, Duke has also petitioned the IURC to approve \$121 million for a site assessment and characterization plan for “sequestration options including deep saline sequestration, depleted oil and gas sequestration and enhanced oil

recovery for the CO₂ from the Edwardsport IGCC facility.” The Office of Utility Consumer Counselor supported the proposal, but advocated that Duke break the work into phases, with the IURC approving only \$33 million at this time. Duke expects a decision by Q2 2011, according to the report.

For power utilities and merchant generators looking at major capex projects, James of EPRI says there’s evidence that cost escalations like those that impacted the industry from 2003 through 2007 are coming back. “From the standpoint of escalation of material and fabrication of components, it looks as though the recession has sort of ended. We’re seeing resumption of cost increases, due in large measure to the increase in power systems development going on around the world.”

EPRI PRISM Analysis Concludes Massive Investment Leap Needed

Cost overruns, financing difficulties, battles with regulators and consumer groups over rate recovery are just the beginning if the United States is to put itself on a course to achieve anything like the 80% GHG reductions by 2050 advocated by many climate scientists and recently endorsed President Obama.

2009 Prism Technologies Performance/ Deployment Assumptions

Technology	EIA Base Case	EPRI Prism Target
Efficiency	Efficiency Load Growth+0.95%/yr	8% Additional Consumption Reduction by 2030
T&D Efficiency	None 20% Reduction in T&D Losses by 2031	20% Reduction in T&D Losses by 2032
Renewables	60 GWe by 2030	135 GWe by 2030 (15% of generation)
Nuclear	12.5 GWe New Build by 2030	No Retirements; 10 GWe New Build by 2020; 64 GWe New Build by 2030
Fossil Efficiency	40% New Coal, 54% New NGCCs by 2030	+3% Efficiency for 75 GWe Existing Fleet
CCS	None	90% Capture for New Coal + NGCC After 2022; Retrofits for 60 GWe Existing Fleet
Electric Transportation	None	PHEVs by 2010: 40% New Vehicle Share by 2025; 3x Current Non-Road Use by 2030
Electrotechnologies	None	Replace 4.5% Direct Fossil Use by 2030

Source: Electric Power Research Institute, Inc.

EPRI's Prism analysis, originally done in 2007 and updated in 2009, has modeled what kinds of clean generation deployment would be needed to achieve such a target. As James explains, achieving such a goal would require a quantum leap beyond what current technology, market and regulatory forces could inspire.

"People generally don't appreciate how significant that kind of CO₂ constraint would be," said James. As he points out, the U.S. electricity sector was responsible for about 2.7 billion tons of CO₂ emissions (GTCO₂) in 2008 out of about 5.7 GTCO₂ total. "The entire economy would have to get close to one gigaton, about 40 percent of what we're emitting now only from electricity sector."

As seen on the chart on page TK, getting on such a glidepath to GHG emission reductions would require massive, sustained investment—starting now—in CCS, nuclear power, renewables, demand-side efficiency, transmission and distribution efficiency, electric transport and substitution of low-carbon electricity for fuel combustion in space, water and process heating. "The point to make is that if we're going to go after CO₂ as stringently as what has been talked about, that's going to drive a lot of more-expensive technology choices than what we'd do otherwise," said James.

Getting there from here seems almost unimaginable in the current economic and political climate. One bright spot on the policy landscape is the emergence of a constituency supporting a national clean energy standard that would support nuclear, cleaner coal and perhaps efficient natural gas along with renewables. "There's definitely some buzz starting in Washington over a clean energy standard," said James. As this edition went to press, however, it became apparent that the nuclear power crisis in Japan could diminish support for a new generation of nuclear plants in the United States. ⚙

Opinions on Impact of Unconventional Gas on the Energy Market

CCBJ's Future of Fossil Fuels Survey respondents were asked an open-ended question on shale gas and its impact on coal, prices and renewables. The following are edited responses.

- Coal is a very abundant global resource while gas is somewhat limited... As gas stocks dwindle, prices will rise. No matter the effect, with all the will in the world renewable energy will never be able to replace base load power.
- Gas will displace coal in many circumstances... Having said that, the potential of natural gas to meet all the reductions necessary (as well as its availability) has been overstated. The price of natural gas prices is historically extremely volatile... I don't see that changing There will not be a huge effect on renewables.
- Natural gas in the U.S. will displace coal fired plants steadily, provided gas prices remain low enough for power plants to convert to gas fired plants... In the U.S., gas prices will remain stable, as more gas is extracted and new fields developed... Gas works 24/7... and will force the alternative sources to introduce prototypes that are cost effective (which is unlikely at present).
- Natural gas price volatility seems inevitable, especially as environmental externalities (land and 'hydrofracking' impacts) come to bear in policy. Profligate gas use, mirroring 'plug load' electricity use escalation, particularly in buildings, is bound to increase price pressure, compounded by natural gas use in transportation, an easier shift than to electricity. Demand for gas appears poised to overtake current supply optimism. Rising gas prices can help boost renewables development.
- Coal will remain cheaper as long as the availability exists, the western U.S. has enough coal for hundreds of years. Coal will always be the option based on cost.
- I believe nuclear will displace coal. The impacts on groundwater from fracking have yet to be fully understood and this could greatly impact viability of deep extraction. Renewable needs to have an ROI without govt subsidy. Natural gas will further reduce govt subsidy and therefore reduce renewable energy development.
- I don't believe that gas will have much impact on coal markets, because gas supplies are more limited. Gas prices will continue to be volatile. Renewable energy will grow significantly, because of rising natural gas prices.
- I think CCS technology will reduce the likelihood that coal will displace natural gas, and gas will become harder to recover over time... Renewable energy development will not accelerate until it becomes cost competitive and that will require governmental subsidies to shift from the development of fossil fuels to renewables.
- Improved accessibility of natural gas will lead to medium-term displacement of coal. Quantitatively, though, coal will eventually prevail.
- In the very long run gas will not be a solution; through 2020/2030, lower gas prices will likely displace some coal in the U.S. Will also make strong penetration of renewables in the U.S. harder. The same dynamics don't apply in Europe, where gas is seen as quite insecure and basic commitments to renewables much stronger.
- Natural gas is speeding the transition away from coal, but also hampering renewables. Regulatory pressures on the gas industry will increase as information on impacts of fracking is more widely distributed.

Source: CCBJ's Future of Fossil Fuels Survey 2011. Question was: Many analysts say unconventional gas supplies will lead to moderate gas prices for decades to come. This could hasten transition from coal to gas in the power sector. Yet concerns that price volatility will return makes utilities leary of a dash for gas. What are your thoughts on a) the long-term scenario of natural gas displacing coal; 2) the future stability of natural gas prices; and 3) the impact of natural gas prices on renewable energy development?

Utilities Turn to Consulting Firms for Resource Planning

Cost of materials and components rises again as more power systems are developed worldwide.

For most power utilities, consulting firms play a major role in resource planning and analyses of how environmental regulations, fuel price curves, electricity market trends and other factors will affect a power company's or public power entity's generation portfolio and investment decisions going forward. An executive with one firm told CCBJ that resource planning studies generally cost clients from \$500,000 to \$1 million.

For this type of work, the most active firms include **Burns & McDonnell, Black & Veatch, AECOM, URS, Sargent & Lundy** and others. Professional service firms with electric power industry expertise such as **Brattle, Charles River Associates** and **McKinsey Group** also perform such studies.

As highlighted in CCBJ's January 2010 professional services edition, these firms tend to position themselves as superior to the engineering outfits at complex economic analyses. On the other side of the coin, some professional service firms acknowledge that their robust analytical capabilities need to be supplemented by engineering expertise that can best be found outside the firm.

When utilities look at building a new plant, however, engineering firms with power industry expertise are generally part of the process early on, according to Revis James, who heads generation planning research for the **Electric Power Research Institute (EPRI)**.

"When utilities want to build a new plant or make a substantial modification to an existing plant, for example to improve efficiency by recovering waste heat, they usually need an engineering

design organization and a construction organization," said James. "Bigger utilities that have their own engineering staff, such as AEP and Southern Company, often still work with smaller architectural and engineering firms to provide support."

Layers of Analysis and Assessment Precede Significant Plant Changes

The process usually starts with preliminary analyses to validate the market assumptions, economic and environmental justifications for the project. "Usually what happens then is a discussion with the utility regulatory agency to assess whether it will support the ability of the utility to incorporate that investment into rates," said James. IPP divisions of regulated utilities obviously wouldn't have to take this step, relying instead on their assessment of load growth and other market factors in the relevant grid territory.

Resource planning studies generally cost clients from \$500,000 to \$1 million.

"Then you're going to do some kind of environmental analysis to make sure you're not creating more problems than you're solving, and that involves hiring and managing environmental consultants," said James. If lights are green at that point, a more detailed (but still preliminary) engineering plan gets done to refine cost estimates, followed by presentations to top management and utility regulators.

"If your project can survive that and be justified, then you'd probably do more detailed environmental assessments and work with environmental regulators. If that goes well, you'd develop detailed engineering documents, and at some point you're going to start breaking ground or making physical changes to your plant."

Considering the costs and long life of fossil power generation assets—20

years or more for combustion turbines, 30 to 40 years or more for coal or gas/oil steam turbine units—rigorous planning is justified from the electricity consumers' perspective as well as the company's own internal ROI goals. But this complexity underscores the concern raised by the **North American Electric Reliability Council (NERC)** that EPA's air-water-waste regulatory scenario could threaten grid reliability in some regions as utilities, merchant power generators and their consultants and contractors can't simply order up new power plants for delivery in a year or two.

As highlighted by NERC staffers in CCBJ's December 2010 edition, when coal plant owners choose to retrofit for compliance, generators will be off-line for a considerable amount of time. NERC heard from craft labor experts that it can take as long as four years to install scrubbers in a four-unit coal power plant.

There may also be challenges in project financing, finding engineering talent and skilled labor needed to accomplish compliance-driven retrofits as well as construction of new gas-fired power plants to fill the gaps created by the retirements and meet reserve margin requirements. (Ironically, there is little talk of employment or "green jobs" in the debate on EPA's combined regulatory scenario although undoubtedly compliance will require a fair amount of human resources.)

James says that utilities looking at major capex projects won't get much cost relief from the recession. The period of cost escalation that plagued the industry from 2003 through 2007 appears to be returning already, he says.

"From the standpoint of escalation of material and fabrication of components, it looks as though the recession has sort of ended. We're seeing resumption of cost increases, due in large measure to the increase in power systems development going on around the world." ☼

Governments and Utilities Fund Carbon Capture & Storage Projects, But Huge Challenges Face Proponents

Capturing and storing carbon dioxide emissions from coal power plants is a central element in every credible scenario for reducing U.S. and global greenhouse gas (GHG) emissions. Because of the size of the existing coal power fleet, the growth curve of coal power capacity in developing countries, and the volume, distribution and pricing of coal resources, there's no question that coal is going to be a large and growing fuel source for electric power worldwide.

"Approximately one-quarter of energy related CO₂ emissions worldwide are from coal combustion for electric power," said Kevin Heal, a carbon business development manager with environmental consulting and engineering firm **Golder Associates** (Calgary). "Three countries, China, India and the United States, with close to 40 percent of the world's population combined, control half of the world's coal. For issues of energy security and economic growth, these and other countries are not going to stop using coal to produce electricity."

"If you accept that man-made emissions are increasing CO₂ levels in the atmosphere and causing global warming, you have to deal with coal power. And there's no way of dealing with coal power emissions other than carbon capture and storage," said Heal. "That's just an economic fact of how we've organized our societies and where economic growth comes from."

It's not just coal power driving the carbon capture and storage (CCS) imperative. The United Kingdom's Committee on Climate Change, established by the U.K.'s 2008 Climate Change Bill, reports that even the most efficient combined cycle natural gas fired power plants will

have to be equipped with CCS to meet the country's GHG targets. "There are immovable limits to what can be achieved through [efficiency] improvements: without CCS, fossil fuel generation cannot achieve the radical improvements in carbon efficiency which will be needed," stated the December 2008 report.

California's CCS Review Panel stated in its December 2010 report that CCS will likely be needed for California's gas-fired power plants and oil refineries if the Golden State is to reach the 80% GHG reductions by 2050 targeted in the state's climate law, AB32.

CCS has been "identified by [California] refiners as a key option in reducing emissions from their facilities—as well as [by other] industrial facilities, including plants producing hydrogen and low-carbon transportation fuels. CCS can also provide a pathway to de-carbonize the transportation sector through the use of electric vehicles that utilize low-carbon power," wrote the California Carbon Capture and Storage Review panel, which included representatives from federal and state governments, academia, environmental NGOs, electric utilities and CCS legal experts.

CCS will be needed for California's gas-fired power plants and oil refineries to reach the 80% GHG reductions by 2050.

Deploying CCS on a large enough scale to make a significant dent in CO₂ emissions by mid-century will require very large and sustained investments by governments and owners of GHG emitting facilities. **Massachusetts Institute of Technology** researchers, in their 2007 report on the future of coal, estimated that if 60% of the CO₂ emissions from U.S. coal power plants were captured, pres-

Carbon Capture & Storage

Even with some \$25 billion in government funding globally, the emerging CCS industry struggles to get projects funded and permitted. US DOE finally settles on FutureGen funding, and Duke Energy pushes ahead on its ICGCC plant, but other key U.S. projects stall. Still, CCS watchers tally 77 large-scale projects on the boards worldwide, with China, the U.K., E.U. and Alberta leading.

surized, transported and injected underground on a daily basis, the volume of CO₂ would approach that of daily U.S. oil consumption.

Just to capture CO₂ from coal, either pre- or post-combustion, power generators and the governments that regulate them must agree to burden existing and future coal units with capital requirements that will exceed those required for current air pollution controls—and impose an ongoing parasitic load in the neighborhood of 15-20%. Electricity consumers will have to consent to seeing their electric rates go up accordingly, and many citizens will have to accept living for generations above large quantities of sequestered CO₂.

Opposition to CCS could become a serious obstacle as the first projects seek to move forward. Proponents of CCS projects in Alberta—the North American jurisdiction with the most active CCS program—are currently contending with pushback heightened by reports that CO₂ injected in Saskatchewan's Weyburn oil fields has contaminated water supplies and poisoned livestock on a farm. According to the *Vancouver Sun*, the report "could be grave news" for CCS.

As detailed in the Alberta story (p.x), which highlights Shell's Quest CCS project, Alberta's Energy Ministry isn't backing off its \$2 billion commitment to develop four major projects. Sponsors of the Weyburn CCS project have

challenged the findings of CO₂ contamination on the Saskatchewan farm. The picture may become clearer after **Cenovus Energy**, the oilfield operator, and **IPAC-CO₂ Research** conclude their promised investigations later in 2011.

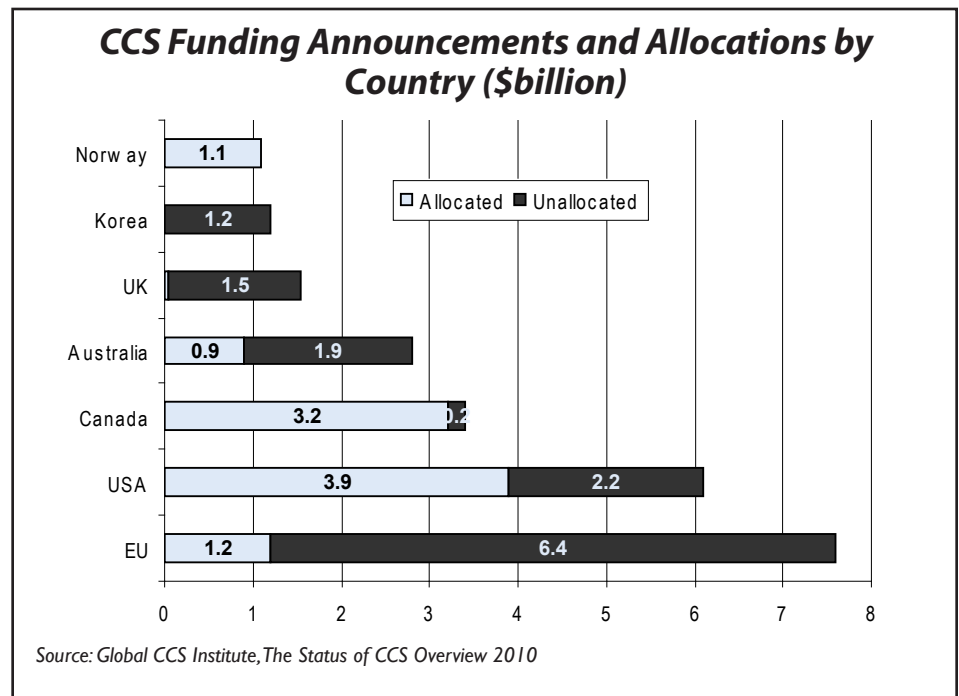
News reports have undoubtedly raised the fear level for some prospective neighbors of CCS projects, making outreach and communications all the more critical.

“There has to be an educational campaign with the backing of government,” said Keith White, general manager of **GE’s** gasification business, which is supplying gasifiers to the developers of two integrated gasification combined cycle (IGCC) power plants in the United States whose owners hope to eventually capture and store CO₂ emissions.

White notes that CCS has a proven track record in the oil business, in which CO₂ is injected into declining oil reservoirs for enhanced oil recovery. “The oil industry has been pumping millions of tons of CO₂ in the ground in West Texas for many years, and there are 3,000 miles of pipelines that transport CO₂,” said White. But he acknowledges that large-scale integrated CCS projects are needed to satisfy skeptical publics of CCS’s safety. “We know all the pieces of CCS can be done. We know we can inject it underground and it stays underground. We know we can produce it from coal power plants. But we need to put all these pieces together.”

Hobson’s Choice? Imperfect Solution But Few Alternatives

As expensive as CCS is, to stabilize atmospheric CO₂ without widespread deployment of the technology will be even more expensive. The **Electric Power Research Institute’s** Prism MERGE analysis of what it would take to cut power sector GHG emissions 80% by 2050 indicated that a “full portfolio” of technology (in which coal with CCS and advanced nuclear play major roles) could enable the



United States to achieve that target for as much as \$1 trillion less than a “limited portfolio” relying mostly on natural gas and renewable power.

“This is a technology that increases the cost of production, reduces the efficiency of generating plants and just causes you trouble,” Jon Gibbins, professor of power plant engineering and carbon capture at the **University of Edinburgh School of Engineering** and a leading U.K. CCS researcher, told CCBJ for our May 2008 CCS edition. “But it’s the only technology that will tackle climate change.”

Gibbins and his colleague Hannah Chalmers published in 2008 a widely cited growth scenario for CCS in which two developmental tranches of CCS projects are deployed before the industry approaches widespread deployment. The first tranche, a handful to a dozen projects, would depend almost entirely on government and industry subsidies. As plants go operational, they would yield key lesson to inform the larger second tranche, which would also be pre-commercial but could be driven by mandatory performance standards with lower levels of subsidies. The third tranche would in effect be the beginning of true commercial deployment,

and for these projects, high carbon prices would provide a significant portion of the return on investment.

As might be expected with the global financial crisis, the timing of CCS deployment modeled by most analysts in 2008 (including CCBJ) has lagged considerably. Many projects have been canceled, postponed indefinitely or reconfigured as less ambitious technology trials, and it’s not yet clear how many of the first tranche envisioned by Gibbins and Chalmers will be operational by 2015.

According the **Global CCS Institute**, formed by the Government of Australia (a major coal user and exporter) in 2008 with \$AUS100 million and joined by hundreds of governments, private-sector, academic and nongovernmental organizations, 24 projects were canceled or delayed in 2009 and 22 cancelled or delayed in 2010. However, GCCSI tallies 234 CCS projects at some stage of development, including 77 large-scale integrated projects (more than 800,000 MT annually for coal-fired power plants and 400,000 MT for other industrial facilities). GCCSI estimates there is about \$25 billion in funding for CCS from the European Union, United States and other governments.

Three Carbon Capture & Storage Technologies

1) Integrated Gasification Combined Cycle (IGCC) With Pre-combustion Capture. This technology involves gasifying coal, then using a shift reactor and gas cleanup equipment to remove CO₂ and other pollutants from the syngas stream, combusting the hydrogen-rich gas in turbines, and using waste heat to make steam to drive a steam turbine.

2) Pulverized Coal (PC) With Post-combustion Capture. With this approach, coal is burned in a boiler surrounded by tubes in which steam is created to drive turbines. The CO₂ is removed after combustion from the flue gas along with other pollutants.

3) Oxyfuel Firing With Post- Combustion Capture. This approach is the same as 2), except the coal is combusted using oxygen instead of air, yielding a much purer stream of CO₂ that makes carbon capture easier. In addition to PC plants, oxyfuel will work with circulating fluidized-bed (CFB) combustion. (A CFB plant could theoretically use post-combustion capture without oxyfuel, but because of CFB's flue gas characteristics, oxyfuel firing is considered the most viable option for CFB combustion.)

Even projects awarded funding will falter as proponents stumble over securing project finance, environmental permitting (including inevitable litigation), regulatory issues like those experienced by U.S. utilities (see below) and other factors.

At a July 2010 CCS forum in Edinburgh, Gibbins presented a "hypothetical failure scenario" for commercial scale integrated CCS projects. Under an optimistic scenario, 80% of the projects aiming to store CO₂ permanently (in deep saline aquifers or depleted oil and gas reservoirs) will fail to go forward, while all of the projects structured to sell CO₂ for enhanced oil recovery (EOR) or enhanced gas recovery (EGR) would succeed. Under a more realistic scenario, the failure rate would be the same for permanent-storage projects, and about half of the EGR/EOR projects would succeed.

Because revenues from EOR and EGR can underwrite capex and operational costs, and because EOR/EGR are already on solid regulatory ground due to the oil and gas industry's long track record with these techniques, such projects usually have better chances of success than those proposing permanent storage in deep

underground formations. For permanent storage projects, there would be no CO₂ revenue other than avoided carbon costs, and the regulatory, permitting and long-term liability challenges will be greater. Four of the seven existing operational CCS projects worldwide use their captured CO₂ for EOR operations.

But EOR/EGR plays can only provide a small portion of the storage capacity needed for CCS to achieve its promise as a climate change mitigation strategy. "EOR is a great opportunity but it's also a limited opportunity," said Ian Silk, manager of Shell's Quest CCS project in Alberta (highlighted in story on page 35). "If you look at the volume of CO₂ on a global scale that needs to be captured and the reservoirs that you'll need to store those volumes, EOR ain't going to get you there."

Thus, projects with permanent storage should be the priority from the climate change perspective; and as Gibbins' scenario as well as the experiences of various project proponents indicates, this is the more difficult and risky pathway to achieving CCS success in the short term.

AEP, Tenaska Run into Opposition; Duke Energy Fares Better

In the United States, CCS proponents **American Electric Power** (an integrated electric utility) and **Tenaska** (an independent power producer with about 9,000 MW under its belt) have seen major projects rejected by utility regulators and legislators concerned over the high costs of their proposed integrated gasification combined cycle (IGCC) technology.

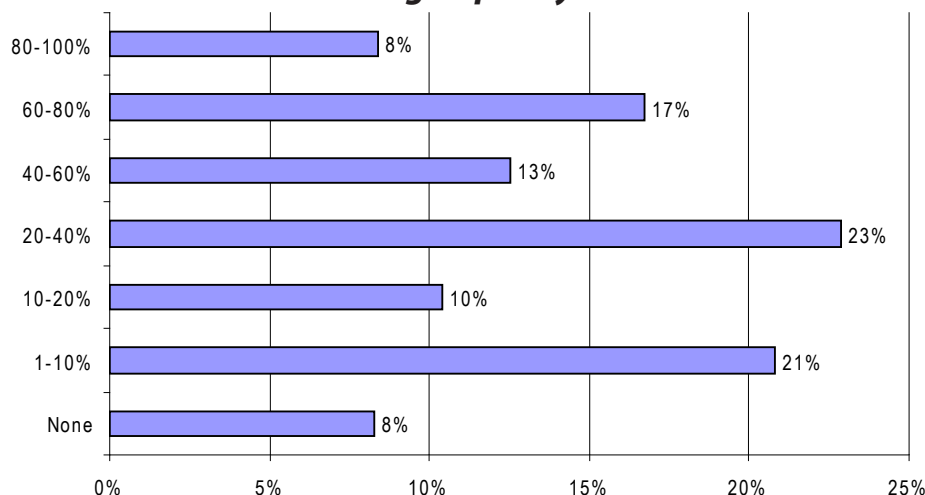
Both projects proposed permanent storage of CO₂ in saline reservoirs or other formations, but the project price tags found excessive by regulators didn't include the carbon capture gear, pipelines, injection wells and CO₂ storage monitoring systems; the plants were proposed to be built "capture-ready."

Duke Energy (an integrated utility with 2010 revenues of \$14.3 billion) fared better with regulators and is expecting its 618 MW IGCC facility in Edwardsport, Ind. to come online in 2012; it would be the third in the United States. But Duke's cost increases and stakeholder challenges underscore the difficulty of building a new IGCC plant.

After \$2 billion was approved for cost recovery by the Indiana Utility Regulatory Commission (IURC) in November 2007, Duke petitioned for and received a cost increase to \$2.35 billion in 2008. Then due to "design changes reflected in the final engineering leading to increased scope and complexity," Duke and its partner **Nucor Steel** requested approval to increase covered costs to \$2.975 billion. IURC approved with caveats, but the agreement unraveled after allegations surfaced of improper communications between the company and a IURC attorney later hired by Duke.

Like AEP and Tenaska, Duke proposed only a "capture-ready" plant, and the company will have to go back to its regulators for approval of CCS infrastructure. A decision is pending on Duke's

U.S. Coal Generating Capacity with CCS in 2050



Source: CCBJ's Future of Fossil Fuels Survey 2011. Question was: What percentage of U.S. coal generating capacity do you think will have carbon capture & storage technology in the year 2050? Mean is 35%.

petition for \$121 million to evaluate its sequestration options.

A key point to note is that when Duke, AEP and Tenaska first conceived their IGCC power projects, the economics of that technology appeared favorable due to high natural gas prices and IGCC's cleaner profile from the perspective of criteria air pollutants. "At the time of [Duke's] approval, IGCC was the least cost option," said Keith White, general manager of GE's gasification business, which is Duke's gasifier supplier.

While natural gas prices have dropped precipitously, air pollution control standards still favor IGCC, according to White. "Most people compare the price of IGCC with what they consider to be standard pulverized coal. They forget to add the cost of SCR's, scrubbers and mercury controls to achieve the levels of control we can with IGCC."

GE is also supplying gasification technology to **Hydrogen Energy California**, a joint venture of **BP** and **Rio Tinto** which is proposing a 250 MW IGCC plant near Bakersfield that would use petroleum coke (an oil refinery byproduct) and coal as feedstock. According to White and HECA's website, front-end engineering and design and permitting is underway,

with commercial operation projected for 2016. HECA proposes to sell CO₂ to **Occidental Petroleum**, operator of the Elk Hills Oil Field. **Fluor** is the primary engineering contractor and **URS** is handling permitting.

Another IGCC project is underway in Mississippi, where **Southern Co.** subsidiary **Mississippi Power** broke ground in December 2010 on a \$2.4 billion 600 MW plant in Kemper County. Built at a lignite mine mouth, the project will use Transport Integrated Gasification technology that has been developed to gasify lignite (characterized by high moisture) by Southern and KBR and tested at the DOE-funded Power Systems Development Facility in Wilsonville, Ala. "The company fought a long battle to get to this stage, including questions from the state Public Service Commission and protests from environmental groups," according to the Gasification and IGCC Forum of *Gas Turbine World* magazine. "The company had originally proposed that it be allowed to pass along construction costs to customers right away. After hearings with the PSC, the company reached an agreement to delay adding those costs to power bills until 2012." According to Energy Central, the project has received \$682 million in federal support including tax credits and DOE clean coal

funds. Plans call for 65% of the carbon in lignite to be captured, giving the plant a carbon emissions profile similar to a 600 MW natural gas combined cycle plant, according to Gasification and IGCC Forum. The captured CO₂ will be sold for enhanced oil recovery.

IGCC Versus Post Combustion Capture for New Coal Plants

IGCC is considered by many in the power industry to be preferable to post combustion (PC) capture for new coal plants that will be fitted with CCS down the line. In addition to the advantages discussed above, separating CO₂ from the syngas produced in gasification is significantly easier than capturing CO₂ post-combustion from flue gas.

However, IGCC is technologically complex to build and operate; there are only two existing IGCC plants in the United States and a handful worldwide. While coal gasification is much more widespread—mostly to produce ammonia, methanol and other chemicals but also for commercial syngas production—integrating a combined cycle power plant with gasification is a challenge of a different order.

IGCC is also more finicky than PC about coal quality, and most of the research on IGCC performance has been done with high-grade bituminous coal. IGCC designs are also less able to cycle in response to fluctuating grid conditions than PC designs. As MIT researchers noted, the choice between pre-combustion capture with IGCC and post-combustion PC designs involves "a delicate balancing of considerations" ranging from fuel markets to evolving air quality standards.

A third strategy for new coal power plants equipped with CCS is oxy-firing: By firing boilers with oxygen rather than air, a purer stream of post-combustion CO₂ results, making carbon capture easier.

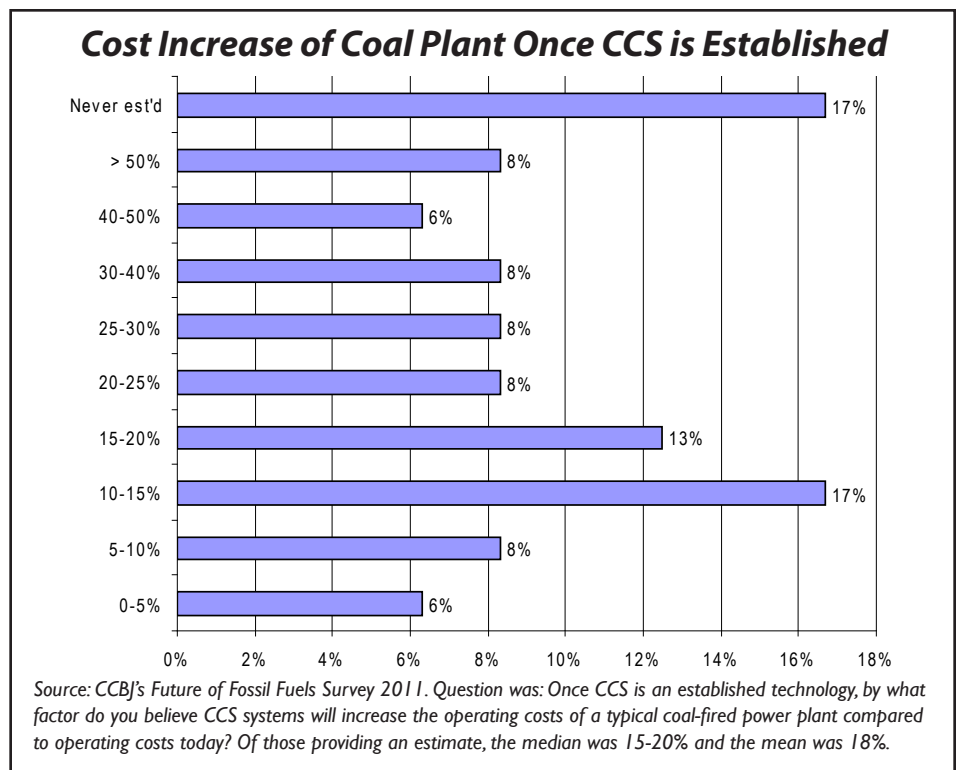
According to the GCCSI, pre-combustion capture has been chosen by the largest number of proponents (33), followed by post-combustion capture (21); post combustion capture with oxy-fuel (4) was a distant third. Sixty percent of the pre-projects are power plants with the rest including syngas production (5), coal-to-liquids (3), fertilizer (3), oil refining (2) and hydrogen production (1).

A key motivation for developing post-combustion capture technologies is the imperative to retrofit existing coal power plants and those that will come on line in the next decade or two. For that task, only post combustion capture technology will work—including the oxy-firing method.

The leading post-combustion capture project in the United States is operated by **American Electric Power (AEP)**. As described more fully on p.X, in September 2009 the company began capturing CO₂ in flue gas equivalent to 20 MW of the capacity of its Mountaineer, Va., coal-fired plant. Using Alstom's chilled ammonia technology, the system captures up to 90% of CO₂ in the slipstream and injects it into saline aquifers beneath the power plant.

AEP has received \$335 million from the U.S. DOE to fund half the cost of scaling up the project to a slipstream equivalent to 235 MW—about 1.5 million MTCO₂ per year. AEP has also received a \$4 million commitment from the GCCSI. But so far, AEP's discussions with utility commissions in Virginia and West Virginia, whose ratepayers are served by Mountaineer, haven't been very encouraging.

The **U.S. Department of Energy** made a major shift (starting under the Bush Administration) away from IGCC and toward post-combustion capture when it abandoned the original FutureGen IGCC concept and awarded funding instead to retrofit an existing plant: a 200-megawatt oil-burning unit owned by electric and gas



utility Ameren in Meredosia, Ill.

The retrofit will convert the unit to an oxy-firing coal-fueled boiler, in which an air separation unit will feed straight oxygen to the boiler, yielding a purer—and more easily separated—stream of CO₂ in the flue gas. **Babcock and Wilcox** and **Air Liquide** are the primary contractors. According to *EnergyBiz Magazine*, the \$1.4 billion project will receive \$1 billion in U.S. Recovery Act funds and \$250 million from the FutureGen Alliance, which includes (according to the FutureGen website) coal producers Alpha Natural Resources, Anglo-American, Consol Energy, Peabody Energy, Rio Tinto and Xstrata Coal and PPL subsidiaries Louisville Gas and Electric and Kentucky Utilities.

"Ameren, Babcock & Wilcox and Air Liquide Process & Construction are spending \$150 million to redesign and retrofit the plant," wrote *EnergyBiz*. "Ryan Cornell, a spokesperson for engineers Babcock & Wilcox, said it has made significant R&D investments in oxy-combustion in the past."

The FutureGen website puts the budget at approximately \$1.3 billion with \$730 million budgeted for retrofitting the power plant and about \$550 million for constructing a CO₂ pipeline and storage facility, as well as a training and research center. FutureGen 2.0 will capture about 1.3 million tons of CO₂ annually.

Whether \$1.3 billion or \$1.4 billion is the correct budget amount, the odds are that the amount actually spent will go up significantly. As Duke's experience headlines, clean coal and CCS projects have been plagued with cost overruns, making consumers and regulators more leary of them.

CCS advocates in the United States are enthusiastic about President Obama's endorsement of a clean energy standard to support clean coal, nuclear and renewables in his January 2011 State of the Union address. But the Republican majority in the House quickly announced its opposition. "Republican Fred Upton, who chairs the House Energy and Commerce Committee, criticized the president's clean energy generation proposal, saying consumers and businesses should not be

forced to purchase energy they cannot afford,” according to Reuters.

According to John Thompson, director of the Coal Transition Project for the **Clean Air Task**, federal legislation is needed to amend the tax credit for CCS passed by Congress in 2008. Authorizing tax credits of \$20 per MT for saline injections and \$10 per MT for EOR/EGR (capped at 75 million MT). “The credit’s current unallocated structure does not permit firms to pre-certify the amount they will claim, so it is uncertain for developers,” according to a presentation Thompson gave in October.

The Bingaman-Snowe Advanced Energy Tax Incentives Act of 2010 (S. 3935) would make the tax credit allocated to facilitate pre-certification as well as raise the credit for permanent sequestration to \$35 per MT and set a 10 million MT cap for any one project. Although Olympia Snowe is a Republican Senator, CCBJ was not able to ascertain if House Republican leaders would support S. 3935.

U.K. Energy Ministry Receives Nine Applications for CCS Projects

In the United Kingdom, the Energy Ministry received nine applications by its February 2011 deadline for about \$6.16 billion in EU funding for CCS projects in Britain, according to Reuters. These include:

♦ **Drax and Alstom** applied for funds to support a 426 MW oxy-fuel combustion CCS project at Selby. “Britain’s energy network operator National Grid will develop the infrastructure to transport carbon emitted from the plant out to the southern North Sea, where it will be stored,” according to Reuters.

♦ **SSE** applied for funding to capture and store CO₂ from about 400 MW of the 1,840 MW Peterhead gas-fired power plant in Scotland. Shell and oil services company Petrofac will develop the transport and storage elements of the project,

which aims to store CO₂ in a depleted North Sea gas field operated by Shell.

♦ **Peel Energy** sought support for a new 1,852 MW supercritical coal and biomass power station at Hunterston, Scotland. Petrofac, Doosan Power Systems and Fluor are named as partners with Peel.

According to Reuters, about eight CCS projects across the European Union are expected to be given a share in the funding, which will come in the form of EU Allowances from the EU Emissions Trading Scheme’s New Entrants’ Reserve. Reuters also notes that the United Kingdom is running a separate CCS funding competition which will subsidize four projects for up to \$15.3 billion.

China Could Be First To Construct Integrated CCS, But How Committed Is It To The Technology?

So where will the first integrated CCS coal power project go into operation? Judging by the progress of construction, the odds are in favor of China, where the **GreenGen** consortium is making real progress on its phase-one 250 MW IGCC project which will deploy CCS. Angel Hsu, Yale doctoral student and expert on Chinese environmental policies, visited the GreenGen site in Tianjin in July 2009 and October 2010. While on the first visit, site preparation was still underway; on the second, substantial progress was visible.

“They had constructed administrative buildings and two water cooling towers,” Hsu told CCBJ. She and her colleague Sarah Forbes from World Resources Institute also saw the Siemens turbine. **Siemens** is one of two foreign partners in the Chinese consortium behind GreenGen; the other is **Peabody Energy**.

China is engaged in a host of other CCS RD&D projects with other technologies, including post-combustion capture systems which could be used to retrofit

the country’s enormous coal-fired power capacity, estimated at 600 GW in 2008 and known to be growing at a fast clip.

James Fallows, who wrote the *Dirty Coal*, *Clean Future* cover story for the December 2010 *Atlantic Monthly*, interviewed a range of U.S. industry, government and NGO representatives about China’s progress on CCS, and also about the scale of the country’s energy and carbon challenge. According to Duke Energy’s Chief Technology Officer David Mohler, China is preparing for its urban population to grow by 350 million people by 2025. “They have to build the equivalent of the U.S. electrical system ... by 2025. It took us 120 years,” Mohler told Fallows.

China’s raging need for Gigawatt-hours in the next decade leads some CCS experts to question how willing the nation’s leaders will be to burden existing and future coal power plants with the extra capex and parasitic loads of CCS systems. But Hsu and others point to the country’s announced goals to reduce the carbon intensity of its economy by at least 40% by 2020. “In terms of carbon and climate mitigation technology, they’re very serious,” she said.

“GreenGen is very much a demonstration project,” said Hsu. “They want to see, once they have this industrial-scale project up and running, what exactly the costs would be. But they also say that they hope to have another 20 of these plants online by 2020, all IGCC with CCS.”

GE’s Keith White says “it’s an open question” how broadly CCS will be deployed in China. “I think they’re serious about investing what it takes to do that. Whether it will turn into broad market deployment is questionable.” GE has a large gasification business in China, with 40 operating or under construction, and company recently established a Chinese joint venture with energy giant **Shenhua** to sell coal gasification technology licenses

and pursue IGCC research, development and demonstration projects.

“What China is going to do with CCS is not so different from what we’re doing here. They will debate it, they will invest in it and make decisions on what’s best for their energy economy in the future,” said White. “Their progress is a bit of a wake-up call for the U.S. because they’re deploying wind, solar, nuclear and now cleaner coal at a pace that’s rivaling any country in the world.” With rapid deployment will come competitive advantages, says White.

“Any new technology enters the market at its high price point,” he said. “It’s the volume and implementation of that technology that will actually drive it down the cost curve. China is building multiple nuclear plants and thousands of wind turbines. If they choose to go down that path with IGCC, we see them as having the ability to drive the costs down.”

How about exporting CCS technology to the United States and Europe? Given China’s export-oriented growth trajectory and goals, that certainly must be a part of the country’s goals for CCS. As Fallows pointed out in his *Atlantic Monthly* story, six large U.S. corporations, including GE, Duke and American Electric Power are active in a government-business-university group working on CCS in China.

In January, AEP and electric power company **China Huaneng** announced a cooperative agreement to evaluate Huaneng’s CCS technology for possible deployment in the United States. Hsu believes exporting CCS technology is part of China’s vision. “Siemens is the only foreign technology [the GreenGen project] is using. They’re really trying to be a leader. We usually talk about technology transfer being a one-way route from developed to developing nations, but in this case China wants to be the leader.” ⚙

Opinions on Whether Advanced Biofuels Will Develop Fast Enough to Meet California’s 2020 Low Carbon Fuel Standard

The majority of CCBJ’s Future of Fossil Fuels Survey respondents agreed that refineries would not be able to meet California’s low carbon fuel standard by 2020 with advanced biofuels, but a number of opinions and scenarios were expressed. Following are edited responses to the statement that the petroleum industry and analysts say that advanced biofuels (cellulosic ethanol, algae biodiesel) will not be commercially available fast enough for refineries to meet the LCFS by 2020.

- Lack of commitment and incentives will prove this statement correct.
- The analysts are correct. Production of biofuels will not advance that quickly. The effect on world food supply and adverse environmental impacts caused by such fuel production will prevent this schedule from being achieved.
- They are correct. The commercialization of these technologies will take a long time, not least as a result of research grant funding limitations.
- While biofuels are excellent in theory, there is an inherent lack of sustainability regarding the landscape change required to significantly cultivate the biofeed stocks—plus the infrastructure is not currently scaleable.
- We need to speed development of advanced biofuels to meet California and national timeframes. Long term we will have to look at focusing biofuels on some critical sectors like aviation, offshore marine and long-distance trucking to deal with scale and sustainability concerns.
- The distribution network is the primary problem. Mixing of biofuels with conventional fuels also causes a problem.
- I disagree. I think it is totally do-able, especially with bioengineering available to us as a tool to help this process advance.
- If financial mechanisms can be put into place to support the shift to advanced biofuels, then we respectfully disagree with pessimism about tech readiness. It is poised to scale up rapidly. The cost, however, is likely to be passed to foods, which seem destined to be displaced in the early transition, in California specifically. This may equilibrate in time, but there will be economic discomfort and political backlash.
- That is BS put out by the oil industry. The USA has the technology, intelligence and dedication to make advanced biofuels a significant contributor to our energy independence. The oil industry does not want that to happen while they are still making record profits off the American consumer.
- Technologies can make these fuels at prices that compete at the \$85+/bbl crude. Funding for the units when many are first of the kind will be the problem.
- It is impossible physically and scientifically for biofuels to ever provide more than 10% of energy needs. Biofuels will be abandoned by 2020. Renewable hydrogen will provide 100% of all transportation energy, and 50% of all stationary energy needs by 2050.
- The market will provide solutions that solve the availability challenges, provided the regulatory and taxation variables are known and trusted to remain stable for a fixed period of time.

Source: CCBJ’s Future of Fossil Fuels Survey 2011. Question was: The petroleum industry and some analysts say that advanced biofuels (cellulosic ethanol, algae biodiesel, etc.) will not be commercially available fast enough to allow refineries to meet California’s low carbon fuel standard by 2020, which mandates a 10% reduction in the carbon intensity of transport fuels. What’s your opinion?

Alberta's CCS Projects Approach Green Light as Province Sorts Ownership, Regs & Liability Issues

Reward of developing CCS is to manage its emissions rather than gain proprietary technology advantage, says Shell.

Turning Alberta's Athabaskan oil-sands into marketable petroleum crude is an energy-intensive business with an outsized carbon footprint. Both surface mining and in-situ production require large boilers or heaters for effective separation of bitumen from sand, after which the bitumen must be up-graded—using hydrogen produced from natural gas and more gas for heat—to synthetic crude oil that can be refined into gasoline, diesel and other products.

As widely reported, Alberta is looking to carbon capture and storage (CCS) as the primary mechanism to mitigate CO₂ emissions associated with its oilsands and power industries. To that end the province has put up \$2 billion (all currency figures in this story are in Canadian dollars) to fund four large-scale CCS projects. The province has also implemented an intensity based cap and trade regime (see CCBJ's December 2010 policy edition) with a \$15/ton price floor—nowhere near the \$80 to \$140/ton price range that analysts have cited as sufficient to justify CCS on an economic basis, but at least a starting point upon which a carbon market can develop.

Alberta is also making good progress sorting out the complex ownership, regulatory and liability issues associated with CCS. In fall 2010, the legislative assembly passed Bill 24, the Carbon Capture and Storage Statutes Amendment Act. "Bill 24 addressed the ownership of pore space, granting of sequestration rights and long-term liability management including providing for a post-closure stewardship fund paid for by CCS storage operators,"

said Kevin Heal, a carbon business development manager based in Calgary with environmental consulting and engineering firm Golder Associates.

On the ownership question, Alberta has affirmed that pore space is owned by the provincial government which can grant rights to private parties to store CO₂. The province is "currently setting up regulations that will allow the province to issue pore space leasing permits, which would be long-term agreements to evaluate the geology of the subsurface and use it to store CO₂," said Heal.

"On the liability issue, the liability resides with the project operator or proponent, but the government has established a process in which the province would issue a closure certificate after injections have stopped and certain conditions have been met. The province would basically assume long-term liability from the operator," said Heal. "As part of an entity's injection rights, it will be obligated to make payments into the post-closure fund to pay for long-term monitoring as well as potential remediation activities."

For the \$2 billion in funding, Alberta has signed letters of intent with four project proponents selected out of dozens of outfits that expressed interest, according to **Alberta Energy**. The selected projects include:

- The **Alberta Carbon Trunk Line** (receiving \$495 million), a CO₂ pipeline system designed to dry, compress and transport as much as 14.6 million metric tons (MMtCO₂) per year from upgraders and other facilities in the "industrial heartland" near Edmonton to locations 250 kilometers to the south where it will be used for enhanced oil recovery in mature oil fields and, eventually, permanent storage. At CCBJ deadline, the project sponsor, **Enhance Energy of Calgary**, had received environmental approvals and was negotiating terms for its government funding.

Shell's CCS Project Receives C\$865 Million

Alberta's provincial government wants to use CCS to handle CO₂ emissions from its oil sands and power industries. With \$2 billion to allocate, four projects have been chosen for funding. Biggest purse goes to Shell's saline aquifer injection disposal project, Quest. Injection could start as early as 2015, and Shell is working towards public acceptance in anticipation of regulatory approval. Environmental C&E Firm Stantec is charged with environmental analyses and permitting.

- **Swan Hills Synfuels** (\$285 million) is an in-situ underground coal gasification (UCG) project which will access coal seams about 1,400 meters underground and considered too deep to mine with conventional methods. The technology uses wells to access coal seams, performs the partial oxidation process in situ, and recovers syngas that is similar to natural gas. Swan Hills plans to pipe its syngas to a new 300 MW combined cycle natural gas power plant near Whitecourt. The CO₂—an inevitable byproduct of gasification—will be used for enhanced oil recovery in the Swan Hills area.

- With **Project Pioneer** (\$436 million), **TransAlta Corp.** and partners **Capital Power** and **Alstom** will retrofit the 450 MW Keephills 3 supercritical coal-fired power plant (in the last phases of construction and expected to be commissioned in Q1 2011) in Wabamun, Alb. The new plant replaces four subcritical units retired last year, achieving 60-80% reductions in SO₂, NO_x and mercury and 24% reductions in CO₂ over the older technology while producing the same amount of power, according to TransAlta's website. Project Pioneer will use Alstom's proprietary chilled ammonia carbon capture technology to capture about 1 MMtCO₂ annually from the plant's flue gas and use it for enhanced oil recovery as well as permanent storage in underground saline aquifers far beneath and geologi-

cally separated from freshwater aquifers.

- Alberta's largest grant of \$745 million has been awarded (pending final agreements) to the only project among the four that intends to inject all its captured CO₂ in saline aquifers: The Quest project will capture up to 1.2 MMtCO₂ annually from Shell's Scotford upgrader facility near Fort Saskatchewan, dehydrate and compress it, transport it 90 kilometers north via a new pipeline and inject it more than 2,000 meters underground into "the deepest saline aquifer formation in Alberta known as the Basal Cambrian Sands," according to Shell's website "The CO₂ will be trapped within tiny pore spaces between the grains of the sandstone rock formation and by dissolving into the brine of the saline aquifer."

Shell's partners in the venture include **Chevron Canada** (20%) and **Marathon Oil Sands** (20%). The **Government of Canada** is also contributing \$120 million from its Clean Energy Fund to "help demonstrate CCS technology and advance Canada's leadership on clean energy technologies while reducing greenhouse gas emissions from energy production," according to a Shell news release.

According to Ian Silk, Quest venture manager for Shell, the company's choice to focus on permanent storage in a saline aquifer was driven by a combination of long-term need and short-term competitive and schedule practicalities.

Silk says Shell has a vision of using CCS to mitigate a significant portion of its emission of greenhouse gases (GHGs) worldwide. "We have quite a few gas fields with high CO₂ content where carbon capture and storage could be a very viable technology to abate CO₂ emissions that would otherwise occur" said Silk. Shell is a partner with **Chevron** on a CCS project associated with the Gorgon LNG plant off the coast of Northwest Australia.

To store the volumes of CO₂ associated with an international portfolio of

facilities will require storage in saline aquifers, according to Silk.

Silk echoed the consensus of CCS researchers—summarized in the Intergovernmental Panel on Climate Change's (IPCC) 2007 report on CCS—who say that enhanced oil and gas production and depleted oil and gas reservoirs can only provide a small portion of the storage capacity needed for CCS to achieve its promise as a climate change mitigation strategy. "EOR is a great opportunity but it's also a limited opportunity," Silk told CCBJ. "If you look at the volume of CO₂ on a global scale that needs to be captured and the reservoirs that you'll need to store those volumes, EOR ain't going to get you there."

Revenues gained from selling CO₂ to oil operators can offset the capital and operations costs of first-of-a-kind CCS projects.

Revenues gained from selling CO₂ to oil operators can offset the capital and operations costs of first-of-a-kind CCS projects, and both Alberta and Saskatchewan have declining oil fields that can provide a market for CO₂. Thus, Shell surmised—correctly it appears—that competing applicants for Alberta's \$2 billion CCS fund would propose EOR projects. Shell also reckoned—correctly again—that Alberta's energy officials recognize the long-term importance of demonstrating CO₂ storage in saline aquifers and would view such a project favorably in the competition. "We felt it was strategic for Alberta, too," said Silk. "The province will have to go to saline aquifers to meet its climate change objectives."

"This is an opportunity for us to learn about the technology in a cradle-to-grave project, and an opportunity for the government to prove up this formation

that we're choosing, known as the Basal Cambrian Sands," said Silk.

Capturing the CO₂ emissions from its oilsands crude may also position Shell to supply that crude to refineries that have to comply with low carbon fuel standards, such as that just taking effect in California and being considered in the Northeast and elsewhere.

Shell Reaches Out to Public; Debate Over Saskatchewan Findings Could Be a Challenge

The Scotford Upgrader receives bitumen after it has been treated at the oilsands mining sites to the north and upgrades it to marketable crude. "The main difference between bitumen and crude is the higher ratio of carbon to hydrogen in bitumen," said Silk. "We bombard the bitumen at high temperature and pressure with hydrogen, which we generate by reforming methane with steam. That produces lots of hydrogen, which is great, but it also creates a large volume of CO₂ which is presently vented to atmosphere."

The facility has a nameplate capacity of 155,000 bbl/day, and a second upgrader is going onstream in the first half of 2011 expanding capacity by 100,000 bbl/day. "That's an average throughput, but in reality it cycles up and down. The real issue in our production is on the mining operation, and the two parameters that determine how much we produce each day are how many tons of ore we put into the mining system and what percentage of that ore is bitumen."

Shell's website makes clear that the Quest project is still in development, and that a decision to proceed will depend on "regulatory and permitting approvals, final project economics and consultation with stakeholders." If the project receives a green light, "injection of CO₂ would begin in 2015."

According to Silk, Shell made its regulatory application in November 2010 and

is anticipating a decision from provincial authorities in early 2012. On a parallel track, the company is working to reach out to people who live near the pipeline or above the sequestration site to hear their concerns and outline Shell's plans for monitoring and verification. "Public acceptance is key," he said. "We've done a lot of work with the communities that we'll be working amongst. It's important that they're comfortable with a carbon capture and storage scheme on their doorstep, one that will be there forever."

Potential opposition to Quest and other CCS projects may become more serious after reports that CO₂ injected in Saskatchewan's Weyburn oil fields has contaminated water supplies and poisoned livestock on a Saskatchewan farm. As the *Vancouver Sun* reported, the news "could be grave news" for CCS proponents. "It's a story with global implications, potentially bad ones, for the energy sector."

After the report by **Petro-Find Geochem**, commissioned by the landowners, surfaced in early January 2011, Alberta Energy Minister Ron Liepert announced the province would stand by its "\$2-billion commitment to develop technology to store carbon emissions," according to the *Calgary Herald*. "Carbon capture and storage takes place throughout the world, and all of the data that we have is that it can be stored safely," said Liepert, according to the *Herald*.

In the weeks after the report was released, the **Petroleum Technology Research Centre (PTRC)** and **International Energy Agency's** Greenhouse Gas R&D Program—the lead agency in a Weyburn CCS consortium which includes Canadian, U.S., Japanese and European energy companies and government agencies—challenged the accuracy of the Petro-Find report. According to PTRC/IEA, the CO₂ soil concentrations the consulting firm detected were typical for prairie soils; the carbon isotope signature of soil gas found on the farm was "not anomalous

and does not fingerprint leakage from the Weyburn oil reservoir"; and Petro-Find incorrectly used baseline value from a deep geologic formation to infer that a major shift in the isotopic composition of CO₂ in soil gases on the farm had occurred due to CO₂ injections.

An executive with a consulting and engineering firm active in CCS in Saskatchewan and Alberta also told CCBJ that his firm's review of the Petro-Find study indicated that the study did not support its conclusions that CO₂ was leaking from the CCS project.

In fairness to Petro-Find, a critique of its report is beyond the scope of CCBJ. At deadline, Petro-Find and the NGO **Ecojustice** which is supporting the investigation, responded to the critiques saying they ignored "important factors such as the presence of abandoned oil wells, the presence of faults and fractures and the high pressures under which CO₂ is injected." Ecojustice Staff Lawyer Barry Robinson wrote CCBJ in an email that **Cenovus Energy**, the oilfield operator, has committed to conduct further investigations in the summer of 2011. "Also, **IPAC-CO₂ Research Inc.**, an independent research organization based at the University of Regina, has indicated that they will conduct in depth investigations."

News reports have undoubtedly raised the fear level for some prospective neighbors of CCS projects, making Shell's outreach and communications—and those of other CCS project proponents—all the more critical. "We believe that CCS can be done safely, and we want to have the positive support of the communities that we'll be working amongst," said Silk.

Silk says this belief is based on the fact that CCS uses existing technologies that have been used for many decades by industry to both store natural gas underground (until it is needed to meet the seasonal fluctuations in consumer demand) and to inject CO₂ for EOR.

Among Shell's environmental and monitoring plans are a baseline study to determine CO₂ soil levels prior to any injection and using a marker in the CO₂ it injects underground.

"We are confident that the site we have selected for the Quest Project is a very safe storage site based on the three thick layers of impermeable rock that provide very effective barriers to keep the CO₂ contained in the storage formation," Silk says.

Silk says to provide further certainty that the CO₂ remains securely contained, Shell is developing world-class monitoring systems involving multiple monitoring technologies, with some of the most important monitoring happening deep underground immediately above the storage formation.

According to Silk, in the unlikely event that any CO₂ makes its way though the first or primary seal overlying the storage formation, the combination of monitoring technology employed directly above the storage formation and the addition of a marker in the CO₂ would allow Shell to take immediate steps to address the leakage while the CO₂ is still a couple of kilometers underground.

Because Alberta is already host to intensive and widespread mining and extraction industries, Albertans are relatively accustomed to mining sites, wells, pipelines and other industrial infrastructure. "In Alberta, negotiations with landowners around wells, access, pipeline routes and other issues is quite normal," said Silk. "That's helpful."

On the other side of the coin, prospective CCS injectors must contend with an abundance of abandoned well-bores from previous oil and gas operations—the culprit in the alleged Weyburn leakage, according to Ecojustice. "One of the most significant types of leakage pathways that need to be investigated for any carbon capture and storage project are abandoned

wells, especially older wells where the abandonment and cementing practices are uncertain,” said Golder’s Kevin Heal.

Golder recently worked with University of Calgary’s **Institute for Sustainable Energy, Environment and Economy** on a feasibility study for long-term CO₂ storage in the Wabamun area where the TransAlta project mentioned above hopes to inject CO₂ from its new Keephills 3 coal-fired power plant. The study “examined the feasibility, cost and potential risk of permanent underground storage of 20 [MMtCO₂] annually over 50 years ... in a 5000 km² area,” according to a Golder Science News story.

Golder’s role in the project was developing a risk-based leakage model for simulating underground CO₂ movement with a particular focus on the potential for leakage through existing wellbores. “Imagine a storage container very deep in the subsurface covered by many geological layers, some of which are impermeable rock,” said Heal. “If there have been holes poked down into that, they represent potential leakage pathways to the surface. The key is to identify all these wells. Fortunately Alberta has reasonably good records of where wells have been drilled, but depending on how far back you go, there is not necessarily good data on how sufficiently the wells were abandoned.”

According to Silk, this concern is a primary reason Shell has identified a sequestration site with “zero legacy wells where the CO₂ will be stored.” The 2,000-meter depth of the saline reservoir also is well below oil and gas resources and water resources, according to Silk.

\$1.3 Billion to Build; Measurement, Monitoring & Verification Will Be Key

Shell contracted with **Stantec Consulting** (Calgary) to conduct its environmental analyses and permitting, and other consultants and contractors will be hired if the project moves ahead. “A major contractor will cover the design and

engineering, and we’ll need construction contractors, including mechanical, electrical and civil,” said Silk. The project will use Shell’s proprietary ADIP-X activated amine technology for carbon capture.

Silk says the company’s rough estimate of costs to develop and build the project and operate it for 10 years is \$1.3 billion. Costs will be significantly higher than for those for that capture otherwise vented CO₂ from natural gas processing, such as the iconic Sleipner project in Norway and smaller CCS projects developed by **Blue Source** and others at gas processing facilities in the United States.

“With the type of project like Quest, we’ll have a 15 percent CO₂ stream at low pressure that needs to be compressed for pipeline transport and subsurface injection,” said Silk. “Natural gas processors already have to strip CO₂ from their gas, so there’s no additional cost for the capture part.” He said that because Quest will capture dilute, low-pressure CO₂ streams, the project’s experience will be relevant to coal power plants which face a similar challenge in capturing CO₂ from flue gas.

Quest will be constructed in a modular process with sub-units built offsite. “It’s normal here in Alberta to do that with road-truckable [equipment],” said Silk. “We have a number of vendors we already work with in this regard.” Key equipment purchases will include amine contactor columns, cooling equipment and a compressor system capable of compressing CO₂ to the dense supercritical phase in which it has the density of a liquid but flows like a gas. “Two kilometers underground, the pressure is equivalent to a column of water two kilometers high,” said Silk. “We have to be above that pressure to get the CO₂ in.”

Measurement, monitoring and verification (MMV) systems and contractors will be key players before, during and after CO₂ injection, according to Silk. “We’ll need baseline measurements, and [MMV]

services in the operational phase and in the post-closure phase,” he said.

Shell expects to monitor and verify the security of the stored CO₂ for a number of years post-closure as per government regulations before it will be ready to request that the province take over long-term responsibility, as it has agreed to do in recent legislation. “If you can demonstrate 10 years of closure, you have a very, very good chance of securing success in the long term,” said Silk.

“The pressure in the reservoir begins to dissipate after you’ve stopped injecting CO₂ into the reservoir, so over time the risk of leakage, which is already very small to begin with, reduces even further,” said Silk.

In addition to three to five injector wells, the storage site will have monitoring wells to measure pressure underground. “We’re also looking at some exciting novel 4D seismic technologies to measure the pressure in the reservoir non-intrusively,” said Silk. “Essentially, there’s a speed-of-sound difference for sound waves going through the brine in the reservoir now and sound waves going thru CO₂. Shooting the same seismic survey every couple years will allow us to see real evidence of where the CO₂ is. This method has worked particularly well in the offshore Sleipner storage reservoir.”

In accord with its government funding agreements, Shell will openly share its data and analyses of CO₂ monitoring methods, as well as every other facet of the project, according to Silk. “We’re not looking at this as an opportunity to develop proprietary technology,” he said. “We want to develop our know-how to do CCS projects in order to manage our emissions around the world [but] CCS requires all of us to pull together.” ☼

AEP Explores Gamut of Options to Improve the Profile of Coal-Fired Power

Biomass co-firing, ultra supercritical designs, carbon capture & storage, and natural gas rank in the utility's fossil fuel alternatives.

It's going to be an interesting decade for American Electric Power (AEP, Columbus, OH), which had revenues of \$14.4 billion in 2010 from its eight electric utilities, a vast transmission network and 38,000 MW of generation capacity. One of the two largest coal consumers in the United States (the other is Southern Co.), AEP is a top target of climate change activist groups, and it has enormous potential liabilities associated with climate change regulations and impacts. The seriousness of its exposure is underscored by its role as lead defendant in a landmark climate change nuisance case that will be heard by the U.S. Supreme Court on April 19, 2011.

AEP is investing in demand side energy efficiency, signing contracts with wind power generators in Ohio to meet its renewable obligations in that state and considering solar power projects in some regions, according to Senior Vice President, Generation for Engineering, Project and Field Services Bill Sigmon. The company is also looking ahead to possible large investments in combined cycle natural gas plants to accommodate load growth and replace retired coal units.

However, coal will definitely be a big part of AEP's future. "We fundamentally believe that coal is a key element of domestic energy supply because of the amount of coal resources that are still available in the U.S.," said Sigmon. This perspective is echoed by utility commissions, elected officials, businesses and consumers in AEP's service territories who benefit from relatively low power prices due in large part to the predominance of coal power.

AEP has spent more than \$4 billion since 2004 on air quality control systems, primarily flue gas desulfurization (FGD) or "scrubbers" and selective catalytic reduction (SCR) gear to comply with tightening regulations around SO₂, NO_x and mercury, according to Sigmon. But making coal power "clean" from the greenhouse gas (GHG) perspective is a much greater challenge.

As highlighted in CCBJ's first edition on carbon capture and storage (May 2008), AEP is one of the most active proponents of pre- and post-combustion carbon capture RD&D projects. AEP's plans haven't progressed at the pace it envisioned three years ago. Nonetheless, its CCS project on the Mountaineer coal power plant in Virginia, up and running 18 months, is one of the most advanced in the world. With a \$334 million federal grant promised, AEP is working to take the project to commercial scale.

The company is pursuing GHG reductions—and increases in power output—through improving efficiency at existing coal plants and by developing the ultra-supercritical design for a coal plant being constructed in Arkansas that may become the most efficient coal plant in the nation. AEP is also investigating biomass co-firing, which can cut a coal plant's GHG emissions by 5% or more through the blending of carbon-neutral biomass with coal. AEP has tested co-firing preblended sawdust at its 1300 MW Amos 3 plant in West Virginia and co-firing pellets at two other smaller plants.

As other generators' tests have revealed, co-firing appears technically feasible up to about 10%; after that materials handling, moisture and other issues would pose major equipment and maintenance headaches. "These furnaces were designed to burn coal," said Sigmon. "With biomass you're getting up to 60 percent moisture and high levels of elements that create issues with the combustion process." Drying biomass with equipment is very

AEP Moves Forward with Diverse Strategies

A huge coal consumer, utility giant AEP has been disappointed by state utility commissions which have balked at proposed CCS projects due to cost. Without rate recovery, a \$335 million DOE grant may not be sufficient incentive to expand its one active CCS project to commercial scale. AEP is building an ultra-supercritical coal plant in Arkansas, and new natural gas turbines are also likely to play a role in AEP's next 10-year cycle.

energy-intensive on a large scale, and field drying is usually not feasible because of the large land area that would be required, according to Sigmon. Unfortunately, finding biomass supplies at economic rates has been a deal breaker for AEP thus far.

"We've tried to deal with several suppliers, and they're looking for a much longer-term contract, say 10 to 15 years, than makes sense economically for AEP and our ratepayers," he said. With wind power projects receiving twice the production tax rate of biomass producers, "wind wins out."

Post-Combustion Capture Project is Nation's First, But Expansion Is Challenged

While co-firing and pursuing higher efficiency can create coal power with lower GHG emissions per MWh, there's an international consensus that CCS for coal power will ultimately be needed to stabilize atmospheric CO₂ and mitigate the risk of extreme impacts from climate change. CCS hasn't advanced much in the last three or four years in the United States. Without a price on carbon emissions—and some assurance that the price will rise substantially within 10-15 years—CCS cannot be justified economically. AEP had originally proposed several ambitious CCS projects, including new integrated gasification combined cycle (IGCC) coal power units in Ohio and West Virginia. Both of those are on hold

indefinitely due to decisions from the respective state utility commissions that the high costs for the facilities couldn't be justified—a decision based on the power plant construction costs alone and not the capital and operating costs of potential future CCS systems.

Projects were proposed to be built “capture ready,” with future installation of the steam shift reactors, compressors, pipelines and other CCS gear anticipated only when carbon prices appeared to be headed high enough to justify the capital and operating expenses of CCS.

That leaves AEP's Mountaineer technology validation facility as the company's only active large scale CCS project. Since September 2009, a slipstream of flue gas equivalent to 20 MW of the plant's 1300 MW generation capacity has been diverted to a CCS system built around Alstom's chilled ammonia post-combustion capture technology. The system can capture about 90% of CO₂ in flue gas—up to 100,000 metric tons (MT) per year—which is then compressed to supercritical density and injected into saline aquifers beneath the power plant, one at 7,800 feet depth and the other at 8,200 feet.

Sigmon says the project has had its challenges, but nothing outside the realm of what the company and its partners—**Alstom**, **RWE** and the **Electric Power Research Institute (EPRI)**—expected. “When you take any new technology forward, there is a need for optimization from the engineering and process perspective,” said Sigmon. “This is the first of its kind, at least in North America but perhaps in the world.”

Confidentiality agreements proscribe Sigmon from revealing many details, including the critically important data about parasitic loads imposed on the power plant by the CCS system; once estimated to be as high as 30%, EPRI researchers have estimated in recent modeling that losses could be reduced to 17%. But he

told CCBJ that some of the key developmental issues have included “understanding where the steam takeoffs should be and how to best optimize all the steam flows, as well as optimization of the absorber vessel and recycle vessel. We've gained a great deal of knowledge in the year and a half we've been in operation.”

Now AEP is working on scaling up the project to capture and store a slipstream equivalent to 235 MW of the plant's capacity—about 1.5 million MTCO₂ per year. The stumbling block, as usual with CCS projects, is cost recovery.

AEP has received a \$335 million U.S. Department of Energy grant for 50% of the cost of the commercial-scale project, but the utility would require state regulatory approval to spend the matching \$335 million. “So far, discussions with our utility commissions haven't been very encouraging,” according to Sigmon. “It's difficult to think about raising electric rates for something that's not obligated by any regulation, especially now with everything that's going on from an economic perspective,” he said.

Ultra-Supercritical Combustion Means Higher Output, Lower GHGs

Aside from IGCC configurations, one of the most climate-friendly technologies for new coal plants is pulverized coal combustion operating at supercritical and ultra-supercritical temperatures and pressures. Engineers have different takes on what temperatures and pressure levels qualify a plant as supercritical or ultra-supercritical, but the bottom line is a sharp improvement in heat rate (Btus consumed per kWh of electricity generated) and an increase in efficiency from the standard subcritical plant.

AEP defines ultra-supercritical as supercritical steam above 1100° F; and according to the company, AEP built the world's first supercritical unit in 1957 (it operated until 1975) and today owns more than 17,000 MW of supercritical coal

power capacity. Eking out the next 50–100° temperature increases above historic designs to get to what AEP considers ultra-supercritical operating levels has been challenging. The first AEP supercritical plant operated at these levels, but lack of available metals to tolerate these temperatures has meant that ultra-supercritical operations couldn't be sustained, according to an AEP fact sheet.

Near McNab, Ark., AEP's **Southwest Electric Power Co.** is building a new 620 MW plant that will incorporate the newest metallurgical alloys to operate at ultra-supercritical levels. EPC contractors are **Shaw** and **Babcock and Wilcox**. If the John W. Turk Jr. Plant operates as AEP and its engineers expect it to, its efficiency will be in the neighborhood of 39% versus the 37% achieved by AEP's typical supercritical plant. As a result, emissions of criteria pollutants and CO₂ per MWH will drop—with CO₂ declining from 1.02 tons per MWH at a supercritical plant to 0.96 tons. Adding up the Turk plant's annual output at an estimated 85% capacity factor would yield a reduction of 275,000 MtCO₂ annually from a comparable supercritical plant.

It's important to note that AEP's technology choice was driven by more than a corporate imperative to reduce GHGs. The higher efficiency will mean more output per ton of coal. Also, the ultra-supercritical technology—as well as state-of-the-art air pollution control systems—gave the company some useful leverage to fend off environmental challenges (not enough to forestall all lawsuits, several of which are pending according to the company's latest quarterly report.)

Gas Turbine Capacity Considered

Speaking of the operating efficiency of coal power plants, Sigmon points out that AEP evaluates its coal fleet continually, naming “heat rate champions” and seeking to optimize boilers and turbines for higher efficiency. Noting the company's need to

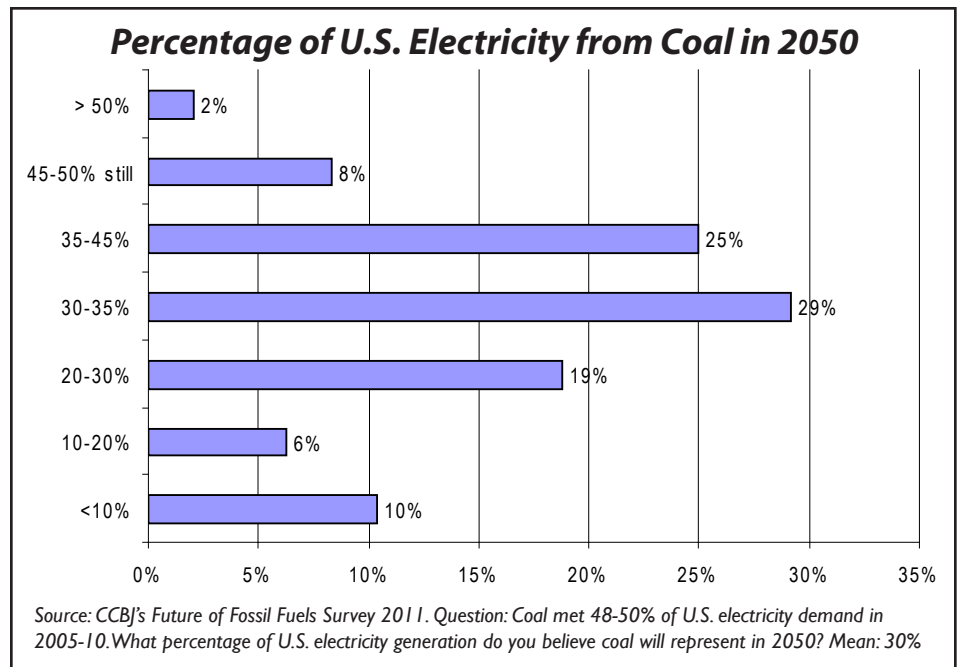
comply with the EPA's New Source Review (NSR) rules, Sigmon says AEP opts not to implement many potential boiler optimizations that could improve efficiency because they would also increase the plant's BTU consumption and emissions.

NSR compliance is a complex puzzle for many large utilities—"arguably the most confusing, politically charged and ambiguous aspect of the Clean Air Act," write NSR experts at Burns & McDonnell—and AEP is not alone in seeking to avoid triggering any potential violations.

As noted above, gas-fired power could be a much larger part of AEP's generation mix over the next decade and beyond. "In our next 10-year cycle, one of the things we're looking at is building some gas turbine capacity in both combined cycle and simple cycle," he said.

Many analysts expect gas prices to remain moderate for many years, and Sigmon says gas suppliers are offering the most favorable prices and terms in his memory, including long-term, multi-year supply contracts. At the same time, turbine manufacturers are rolling out more efficient turbines and collaborating with power engineers to create combined cycle plant designs that can operate more flexibly than past designs which were designed for steady baseload operation.

The capability of a gas turbine plant to cycle up and down is becoming more important as intermittent renewable sources like wind power provide more power on regional grids. "Combined cycle units are able to ramp a lot more quickly than in the past," said Sigmon. "They're doing it in a variety of different ways. Some of them are just bypassing the HRSG (heat recovery steam generator) at least during the startup phase and just running the gas turbine. Some just minimize flow through the HRSG while they get the gas turbine going. There are different configurations by different manufacturers, but not only are they able to give you fast start as with



a simple cycle machine, they're able to give you the favorable heat rate when they're in combined cycle mode."

AEP Configures New Designs With View to Doing Procurement

Sigmon told CCBJ that AEP is developing its own internal reference designs for new combined cycle plants, including two-on-one (two turbines, one HRSG) and three-on-one configurations, with technical evaluations of the turbines offered by the major manufacturers—GE, Mitsubishi, Siemens and Alstom—and others, as well as HRSG manufacturers.

This would position the company to procure equipment on its own, taking on financial risks that a turbine manufacturer or EPC contractor would typically carry—and charge its client for. "It's not that we can necessarily manage the risk more effectively, but if we can order the material, we take some of the financial risk away from the contractor and they don't have to price that risk component in their contract," said Sigmon.

The extent and pace of AEP's investment in new gas-fired power plants partly depends on what happens with climate policy in the United States. Generally considered the country's largest GHG

emitter (a fact that may be confirmed after EPA releases results of 2010 GHG reporting), AEP's management and shareholders could have taken comfort in the results of the November 2010 election.

But an electric utility company making decisions about \$50 billion in current assets and billions of potential investments over the next decade can't depend on the priorities of the 112th Congress remaining the same in ensuing Congresses. Besides, AEP (which says on its website that its challenge is to "ensure a sustainable electricity future in a carbon-constrained world,") appears to have accepted the reality of climate change and the inevitability of climate policy. The company supported the Waxman-Markey cap-and-trade bill that passed the House in 2009, and it would probably still prefer climate legislation to a patchwork of state regulations and EPA rules, not to mention lawsuits.

As described by McKenna Long and Aldridge attorneys in CCBJ's January 2011 Executive Review edition, a key reason the Second Circuit Court decided that the climate change nuisance lawsuit against AEP and other power generators could go forward was because there was no federal legislation to displace the plaintiffs' claims. ⚙

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