Montana’s Crow Nation and Australian-American Energy Co. reported in August that they will jointly construct a $7 billion coal-to-liquid (CTL) fuels plant in southeastern Montana. Plans for the plant were unveiled Aug. 8, with 2016 announced as the likely date for the start of production at the plant.

CTL presents a new scenario for coal, utility, and petroleum companies to work together. Utility companies want to turn coal into electricity, while coal companies seek to expand their market from solely electric power generation to liquid hydrocarbon conversion, and petroleum companies can use the carbon dioxide (CO₂) produced for enhanced oil recovery (EOR).

The economic incentives of using coal with green technology to make electricity and transportation fuel was explained in the O&GJ, Feb. 26, 2007, article, “Fischer-Tropsch oil-from-coal promising as transport fuel.” Specifically, the method couples the integrated gasification combined cycle (IGCC) process with Fischer-Tropsch syngas conversion to develop an advantageous, green CTL system from pairing the two technologies.

New economic conditions

However, much has happened since that economic analysis. Crude oil prices ramped up to more than $140/bbl from about $60/bbl, while plant construction prices escalated greatly as well—although not quite to the degree of crude oil.

Furthermore, CO₂ can now be valued higher because its use in EOR floats with the value of crude oil. Originally $1/Mcf, it recently commanded a price as high as $5/Mcf. IGCC investment costs also have risen—to $2,000-3,000/kw capacity from $1,400/kw capacity.

This article presents the best and worst-case scenarios for CTL based on recent economic conditions. The best-case scenario includes oil valued at $135/bbl, investment costs for IGCC increased to $2,000/kw capacity from $1,400, and CO₂ valued at $5/Mcf. The worst-case scenario has oil valued at $75/bbl, investment costs at $3,000/kw capacity and CO₂ valued at $2/Mcf. The cost for the Fischer-Tropsch section of the IGCC plant was scaled by the same amount.

The economics shown in Table 1 illustrate that a huge increase in capital costs was offset by higher crude oil prices. Specifically, the discounted cash flow (DCF) rate of return increased to 27% for the best-case scenario from the original 15% (Case 3 in the February 2007 article), and it dropped only slightly—to 12%—for the worst-case scenario.

The announcement of the Crow Nation-American-American Energy Co. Montana CTL project is evidence that this clean technology merits serious consideration for future energy projects, particularly when the coproduced CO₂ can be used for EOR.

IGCC plant operations

In a typical IGCC plant, coal is first gasified to synthesis gas—hydrogen and carbon monoxide (CO). The synthesis...
gas is scrubbed to remove acid gases and mercury. The synthesis gas is then burned in the combustion turbine, and the hot exhaust is used to raise steam to drive a second turbine. Both turbines produce electricity, with the thermal efficiency increasing to 40% for combined-cycle operation from 33% for a direct-fired coal unit.

If the synthesis gas is passed through a water gas shift converter before reaching the turbines, the CO converts to H2 and hydrogen. The CO2 can then be scrubbed, providing a hydrogen-rich stream to the turbines. This is an "ultra-green" scenario because there is very little CO2 emitted from the power plant. CO2 cannot be eliminated entirely because some CO must be left in the feed to the power plant for flame stability. The figure shows the process flow for converting coal to electricity and liquid hydrocarbons.

With newer technologies, such as IGCC, coal conversion is an environmentally friendly process. Pollutants such as mercury, sulfur oxides (SOx), and oxides of nitrogen (NOx) are essentially eliminated because coal gasification instead makes hydrogen sulfide and ammonia, and these easily can be removed in acid gas scrubbers. CO2 also can be captured and sequestered. If oil fields are nearby and responsive to CO2 flooding for EOR, then CO2 can provide a significant income stream.

**Clean coal benefits**

Although most people deem coal to be a “dirty” fuel, it can easily be cleaned. Its bad reputation is grounded in its use for many years in direct-burning power plants. It is unfortunate that opposition to coal as part of the solution for US energy needs is based on this older, direct coal burning technology rather than IGCC, which makes an electric power generation facility more like a chemical plant than a coal-fired plant with a tall smoke stack.

With IGCC, coal conversion can be a green technology; the plant can easily capture CO2 from the oxygen-blown coal gasifier because the offgas is not diluted with nitrogen. The CO2 can then be injected into the ground and stored.

In addition, the CO2 produced in the CTL process has tremendous potential for EOR use if a mature, light-oil field is nearby. These synergies suggest that the coal and petroleum industries should cooperate to enable green coal technology to be exploited to increase oil production via EOR.

Benefits of this technology for the US can be enormous because US coal reserves are huge, representing 27% of the total world supply. Consequently this energy resource deserves serious consideration. Coal from the states of Montana, Illinois, and Wyoming alone could be converted, via Fischer-Tropsch syngas conversion, to 300 billion bbl of diesel fuel.

And CTL technology is already off the shelf. Sasol in South Africa is producing 160,000 b/d with this technology, so it is not an immature, undeveloped process.

**Enhanced oil recovery**

In this economic analysis, CO2 production during the CTL process represents a major revenue stream that can offset some of the project’s investment costs. Currently CO2 for EOR commands a price of $1-5/Mcf. Because it takes roughly 5 Mcf of CO2 injection to produce 1 bbl of oil, the price of CO2 will continue to rise correspondingly as oil becomes more valuable.

Oil & Gas Journal’s most recent EOR survey shows EOR projects using CO2 injection increasing, with the 100 ongoing CO2 miscible injection projects accounting for 240,000 b/d of additional US oil production. Despite these advances, scant availability of CO2 currently limits the US petroleum industry’s ability to expand CO2 flooding.

Because CO2 has become a viable product in its own right rather than simply a byproduct, CO2 handling today differs considerably from its handling during the energy crisis of the 1970s and 1980s when it was simply emitted into the atmosphere. As incentive to curtail CO2 emissions, the US Department of Energy has been funding CO2 sequestration partnerships around the country.

**Updated economics**

The updated economics are shown in Table 2 for the previous cases using Montana Rosebud subbituminous coal.
The updated economics assigns diesel fuel a value of $3.90/gal for $135/bbl crude and $2.12/gal for $75/bbl crude vs. the old $1.80/gal. CO₂ in the new scenario would cost $2/Mcf, and the capital investment costs for IGCC are updated to $2,000/kw capacity vs. the old $1,400/kw. The table shows the economics for four processes:

- Case 1—CTL transportation fuels using Fischer-Tropsch synthesis.
- Case 2—Coal-to-electric power using IGCC.
- Case 3—Coal to both liquid transportation fuels and electric power.
- Case 4—Ultragreen technology to eliminate CO₂ emissions from the IGCC plant using hydrogen-rich gas for the combustion turbine. CO₂ in the syngas is shifted to hydrogen in a water gas shift reactor, and the CO₂ is removed and sold.

The good news is that the rate of return is now higher for all of the cases. They benefit from the increased price of diesel fuel and CO₂ even with the higher investment costs. In fact, Case 4 for the ultragreen technology looks very attractive at a 30% DCF rate of return for $135/bbl crude and 26% for $75/bbl crude. The CO₂ produced from Case 4, represents a major revenue stream and shows that plant location is important. The coal conversion plant needs to be within 100-450 miles of the oil field that will be using the CO₂ for EOR. As one example, CO₂ is transmitted via pipeline about 450 miles from Cortez in southwest Colorado to the Texas panhandle. Other examples are given in the OGJ EOR survey.¹

Cost sensitivity studies

The impacts of higher capital costs and higher value for CO₂ in Case 3 are illustrated in Table 3. It shows the results of a cost sensitivity analysis of capital costs for Case 3, using the much higher value of $3,000/kw to show its impact on the DCF rate of return.

Case 3a shows the result of changing the capital investment basis to $3,000/kw capacity from $2,000/except while keeping CO₂ valuation at $2/Mcf. The second sensitivity, illustrated as Case 3b, shows results of changing the CO₂ valuation to $5/Mcf from $2/Mcf, and with everything else held constant from Case 3a. These new cases are shown in the Table 3 cost sensitivity study results.

Case 3a, using the higher capital investment of $2.4 billion, results in the return on investment dropping to 15% from 20%. This rate of return is still attractive at the higher investment costs and gives some confidence that a potential investor in this project would not be subject to an economic failure, even if...
source of energy in the US. It will take a clear government policy on energy and the environment to convince investors to move forward with these kinds of projects.

There are a number of ways the US government should take the lead in this effort:

• Organize a consortium of oil, coal, and power companies to design, build, and operate the plants. Production of electricity and CO₂ for EOR will cushion the economic downside when crude prices drop.

• Continue the 80% loan guarantee for synfuels plants.

• Provide a price support for the product from the plants, perhaps guaranteeing to purchase the entire liquid product at a set price. This guarantee would not be substantial for the initial plants, which would produce 5,000-10,000 b/d of liquid fuels.

• Offer tax credits to corporations to build and operate “green” and “ultra-green” coal plants that produce either electricity or liquid fuels.

• Streamline environmental permitting so that construction can proceed in a timely manner.

These initiatives could pave the way for a new, robustly ample and clean domestic energy supply for the US.

**References**


**USGS estimates ANS holds 85.4 tcf of gas hydrates**

Nick Snow
Washington Editor

There are 85.4 tcf of undiscovered, technically recoverable natural gas resources in gas hydrates on the Alaskan North Slope, reported US Geological Survey on Oct. 18.

The US Department of the Interior agency said scientists recently completed the first assessment of an area extending from the National Petroleum Reserve-Alaska (NPR-A) on the west through the Arctic National Wildlife Refuge (ANWR) on the east, and from the Brooks Range on the south, to the state-federal offshore boundary 3 miles into the Arctic Ocean off the northern coast.

The 55,894 sq miles consists mostly of federal, state, and Alaskan native lands, USGS noted in a new report. “Approximately 35 years ago, Russian scientists made what was then a bold assertion that gas hydrates, long a curiosity of physical scientists, should occur in nature. Since then, the USGS and others have built a strong foundation supporting the conclusion that gas hydrates are a global phenomenon containing potentially huge volumes of gas in terrestrial Polar regions and the deepwater portions of most continental margins,” it said.

It explained that gas hydrates are naturally occurring, ice-like solids in which water molecules trap gas molecules in a cage-like structure known as a clathrate. Although many gases form hydrates in nature, methane hydrate is the most common by far, it added.

The report said that when USGS conducted the first systematic assessment of US in-place natural gas hydrate resources in 1995, the study suggested that the amount of gas there greatly exceeds the volume of known conventional gas resources. Recognizing gas hydrates’ importance as a potential energy resource, USGS and the US Bureau of Land Management agreed in 2002 to assess the volume of hydrates that could be produced in northern Alaska, it said.

**A producible resource**

“For the first time, the USGS has assessed gas hydrates—a traditionally unconventional source with no confirmed production history—as a producible resource occurring in discrete hydrocarbon traps and structures,” it pointed out.

The assessment’s primary purpose was to conduct a geology-based analysis of gas hydrates’ occurrence within northern Alaska to determine the role