

THE ART OF THE POSSIBLE

A LOOK INTO THE FUTURE VIA THE HISTORY OF DAKOTA GAS

BY TRACIE BETTENHAUSEN

Take a minute to remember a not-so-distant past. In the mid-1990s, natural gas prices were very low. At Dakota Gasification Company's Great Plains Synfuels Plant, employees were coming up with ways to diversify from natural gas. By developing byproducts, the Synfuels Plant increased its revenue during a time when a \$1.96-per-dekatherm natural gas price wasn't covering the cost of production. (A dekatherm is 1 million British thermal units.)

Dakota Gas was in talks with PanCanadian, an oil company in the Canadian province of Saskatchewan. (PanCanadian, whose name changed to EnCana, is now called Cenovus.) Paul Sukut, Basin Electric chief financial officer, was then Dakota Gas' vice president of finance. "We were meeting with PanCanadian, trying to hammer out what we would charge them for carbon dioxide. They were wondering about the long-term viability of Dakota Gas," Sukut says. "They said, 'How are you going to pay for the capital costs of building that pipeline and compressor?' This was going to be a \$100-million investment."

Sukut admits, the answer wasn't there. Kent Janssen, then Dakota Gas' vice president, looked around the room. "He jokingly said, 'Maybe a miracle?'" Sukut remembers.

"We were hoping for a miracle as far as financing the capital costs of putting this pipeline in," Sukut says. Dakota Gas borrowed money from Basin Electric. Not long after, natural gas prices went up, Dakota Gas paid off its loans plus interest,

and today, the Basin Electric subsidiary is nearly debt-free.

This success story is one of several in the company's history. The decisions made along the way weren't easy; they wouldn't affect only Basin Electric, but every member cooperative. The Synfuels Plant was not expected to survive until it did. When natural gas prices are high, everything's great. But when those prices fall, eyes turn to the plant that was once called a white elephant and worse.

“We're not thinking of having to drill another hole to get more gas; we're producing it consistently. We're a long-term investment and we give Basin Electric an advantage in producing electricity.”

Gary Loop, Dakota Gasification Company

A history in the red, then well into the black

When Basin Electric's members voted to buy the Synfuels Plant, they did it in part to save Basin Electric money, and in part so no one else could take it over just to shut it down. If the plant had shut down, it "would have resulted in a big loss of electrical load, about 90 megawatts for Basin and its members," according to "The New Synfuels Energy Pioneers," a book detailing the history of Dakota Gas.

The U.S. Department of Energy had assumed ownership of the Synfuels Plant in 1985, when its original owners defaulted on their loan. When Basin Electric paid \$85 million to the Department of Energy, \$16 million was for the plant, and \$69 million was for the mining rights and other equipment to continue operations at the Freedom Mine, according to Andy Buntrock, director of financial services for Dakota Gas.

The risk was that if Basin Electric didn't buy, another owner would shut it down, which would have had ongoing implications for Basin Electric. "We've seen impacts even when short-term events have happened," says Faye Miller, director of financial services for Dakota Coal Company. "When the Synfuels Plant has had to go into an unscheduled shutdown, lignite deliveries from the Freedom Mine have been reduced. Using today's production costs at the Freedom Mine, for every 100,000 tons of reduced lignite deliveries, the cost per ton of lignite to the mine's other customers would increase by about 7 cents per ton." Now consider that each of Basin Electric's power plants uses millions of tons of coal per year, one can understand the economic impact to the Basin Electric membership.

For the most part, Dakota Gas has been able to pay its own debts. But when big projects needed to be done – the CO₂ pipeline, for example, or when the plant needed to install equipment to reduce sulfur dioxide emissions – Dakota Gas borrowed money from Basin Electric.

Over time, Dakota Gas paid back its debts to Basin Electric and the Department of Energy. The United States government has recovered more than \$1.2 billion of its \$1.5-billion investment through revenue sharing, foregone production tax credits of approximately \$754 million and the initial purchase price of \$85 million. 2009 was the last year of Dakota Gas' revenue sharing with the Department of Energy.

In 1994, Dakota Gas made its first small dividend payment to Basin Electric. By the end of 2006, Dakota Gas was officially out of debt to Basin Electric. Major dividends began in 2007, and the Basin Electric board of directors chose to pass some of them through to the membership as bill credits.

Besides the benefit Dakota Gas brings Basin Electric when natural gas prices are good, the Synfuels Plant brings benefit

continuously. The plant was built in conjunction with Basin Electric's Antelope Valley Station and the Freedom Mine. The Synfuels Plant shares resources such as coal supply and facilities for water intake, delivery and storage. The Synfuels Plant sells, at a reduced price, its unusable coal fines to Antelope Valley to burn as fuel, a resource Antelope Valley would have to buy otherwise.

"We are joined at the hip. There are three of us: the coal mine, Antelope Valley Station and the Synfuels Plant. They do work well together; they were designed from the ground up to be that way," says Gary Loop, chief operating officer for Dakota Gas.

Allowing Basin Electric to avoid risk

The United States holds one-third of the world's coal, and the Synfuels Plant is one of just two plants in the world that take coal and turn it into natural gas. The construction of Basin Electric's natural gas peaking plants and a combined-cycle power plant are all linked to the Synfuels Plant. "The fear of building those plants is that natural gas could spike to \$20. Because we (Dakota Gas) own a gas plant, we can invest in power plants that use natural gas. If you can produce natural gas for \$5, you don't have to be afraid of \$20 gas," Loop says.

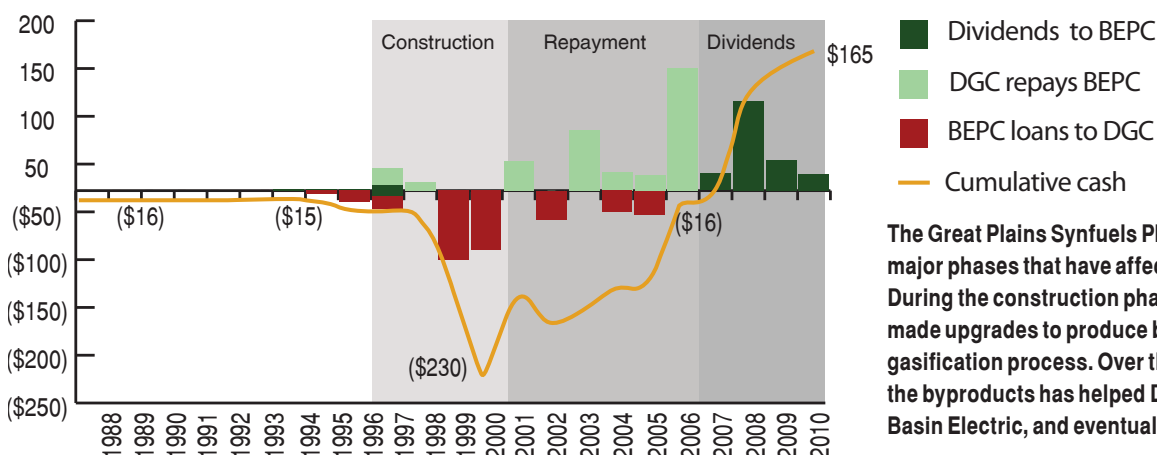
Basin Electric pays Dakota Gas market price for their natural gas. However, all revenue above what it costs the Synfuels Plant to produce the gas comes back to Basin Electric as a return on its investment.

Loop says natural gas from a coal mine is a sure thing. "We're not thinking of having to drill another hole to get more gas; we're producing it consistently. We're a long-term investment, and we give Basin Electric an advantage in producing electricity."

Buntrock says the benefit can be hard to see on the surface; you have to see the price Dakota Gas is getting through hedging arrangements. "Someone might say, 'We know your cost of

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DGC: A financial timeline



The Great Plains Synfuels Plant has gone through major phases that have affected Basin Electric. During the construction phase, the Synfuels Plant made upgrades to produce byproducts from the coal gasification process. Over the next decade, the sale of the byproducts has helped Dakota Gas repay loans to Basin Electric, and eventually pay dividends as well.

production is right around \$5. And I know that I can look online and see that gas is selling for \$4.50. So how can you tell me that Dakota Gas isn't a drain on Basin Electric?" Buntrock explains, through hedging, Dakota Gas is making more on its gas than the market value. In fact, the current hedges, set through May 2015, are worth \$20 million-\$50 million per year. Seventy percent of the available gas production is hedged to be sold above the cost of production.

"In early 2009, we revised our policies and procedures for managing the natural gas price risk," Buntrock says. "We have guidelines for how we hedge that force us to layer our hedges. On a schedule, we're making new, forward-looking hedges that protect us."

The company is projected to make \$28 million before tax net income in 2011, Buntrock says. That revenue will help the plant maintain a positive cash flow.

The man with the plan

"As you look into the future, if you were to take our current financial forecast, it shows us falling behind, turning negative in the year 2017," Loop says. "However, that assumes we continue operating the way we are today, and we have no intention of doing that."

When Loop was hired in 2006, he was given the assignment of creating an operation at the Synfuels Plant that is sustainable. "We're on a major path to hit a production cost of \$5 per dekatherm in 2016."

Producing natural gas at or below the \$5-per-dekatherm mark is the goal Loop has been pushing the plant toward. If the plant continues making improvements, projections show the Synfuels Plant will make \$30 million-\$40 million during the years, under the current operating scenario, the plant is projected to lose money, according to Buntrock.

Loop says the plant has a list of projects, some vetted and approved, some not, that save money and/or increase revenue at the plant. (See page 5 for projects being implemented.)

"We've filled our pipeline, if you will, with projects, and now they're popping out at the end. We didn't just rest on our laurels. Today, instead of worrying and thinking and calculating, we're working on the projects that will bring us to the \$5-per-dekatherm goal," Loop says.

So how does Loop know the \$5-per-dekatherm goal is enough? He says shale gas and fracking have changed the natural gas market. "Shale gas is being produced for \$3.50 to \$6.50, depending on the field. While there are some companies that can produce shale gas for \$3.50, they're not big enough to drive the market down, because if the price went that low, other producers would stop producing. There'd be less gas, and the price would go back up."

Loop says natural gas producers don't necessarily drill a hole to get gas these days. "The biggest cost of getting gas out of the ground was the up-front capital costs to drill the hole and lay pipe to get it to market. You'd punch a hole and produce for 10 years. So if the price of gas drops, you're not going to stop producing because you've already spent your money."

Loop says the new fracking wells are different. Because a majority of the gas is produced within 18 months, producers hedge their entire production before even drilling the well. "The minute the price would drop below their costs, they'd stop drilling and the market will react within 18 months as opposed to years. That makes the market more reactionary; you can't have – we don't believe – long periods of time where the price is below what it costs to produce it."

Making their own miracles

Perceptions of the Great Plains Synfuels Plant will always ride on the natural gas price tide. But Loop says the employees of Dakota Gas are focused on keeping the plant viable. "They're working on it and doing something they believe is going to make a difference. It can be pretty exciting. Just like the guy going to the Super Bowl. He's nervous as hell, but he's glad he's going."



Making a hedge: A product is sold ahead of time to avoid the market fluctuations associated with that product. For example, you sell the lemonade you will produce next month at a price you believe will still cover the cost of lemons, sugar and labor next month.

In 2011, Dakota Gas has hedged 73 percent of the Synfuels Plant's available natural gas production. The price is not only above the cost of production, but above today's market price. Through May 2015, the current hedges on available production are worth \$20 million-\$50 million in gross revenue per year.

PROJECTS TO SAVE MONEY

Compiled by Joan Dietz and Tracie Bettenhausen

Some of the people working on new ideas at the Great Plains Synfuels Plant. (From left) Dale Johnson, Robin Braun, Bob Weir, Gene Baker, Mike Just, Claudia Miller and Jerry Sanden.



The Synfuels Plant has been on a path to natural gas production at or below \$5 a dekatherm. “People get nervous because if you don’t meet the curve, you’re in trouble. Let me tell you, the employees of Dakota Gas can see that, and they have no intention of shutting down their plant,” Loop says. “They’ve got their whole livelihood riding on this and they’re coming up with ideas. It’s a fantastic system.”

Clean cooling water

In January, directors approved a \$77-million clean cooling water project at the Synfuels Plant.

The project will add eight plate and frame heat exchangers, including ancillary equipment that will be used to cross exchange the existing dirty water with the new clean water system.

The project is projected to save \$15 million annually in maintenance by avoiding costly outages.

“The existing exchangers will see the clean water instead of dirty water, allowing us to extend the time between turnarounds,” says Claudia Miller, engineering manager for Dakota Gas. “With the addition of the new system, we will complete maintenance turnarounds every two years instead of every year.”

SNG booster

The installation of the synthetic natural gas booster compressor at the Hebron metering station will allow the Synfuels Plant to maintain high production “even during increased Northern Border pipeline pressures,” says Bob Weir, supervisor of project management for Dakota Gas. “This has been a significant plant limiter over the last several years.”

The compressor arrived at the Synfuels Plant in early January. It is a gas-driven reciprocating compressor that will use natural gas from the pipeline produced at the Synfuels Plant.

The yearly benefit of this project is about \$1 million.

Waste stream in phenosolvan project

It was determined last year that two waste streams from the phenosolvan area needed to be handled differently. In mid-December, a group of process engineers, process operators, environmental and chemistry lab employees put their heads together. Mike Jones, process engineering supervisor, says after several ideas, they came up with a winner: a stripping tower in which the waste streams are routed to an existing tower in the phenosolvan unit.

“Bringing the stream back to recycle in the distillation tower allows us to recover the IPE (isopropyl ether) in the stream, which, in the end, saves us money,” says Robin Braun, process engineer.

The new concept was tested over a chilly three-week period in January. “The process operations and maintenance employees were very instrumental in testing this concept during the most frigid part of our winter,” Braun says. The chemistry lab completed extra analysis during the test period.

After testing was complete, the new concept proved to be successful. Not only is the cost to implement the project cheaper than other options, at about \$1 million compared to some more than \$4 million, the ability to reuse the IPE stream is cost-effective.

“We went from a project that would have lost us money, to a project that will make us money,” Braun says. Depending on how the unit is running, it is estimated that \$100,000 to \$400,000 can be saved every year in IPE costs.