DAKOTA GASIFICATION COMPANY
GREAT PLAINS SYNFUELS PLANT

THE HIDDEN VALUE OF LIGNITE COAL

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DAKOTA GASIFICATION COMPANY BACKGROUND

The Great Plains Synfuels Plant is the only commercial-scale coal gasification plant in the United States that manufactures natural gas. The synfuels plant is owned and operated by Dakota Gasification Company (DGC), a subsidiary of Basin Electric Power Cooperative(BEPC).

The plants genesis lies in the energy crisis of the 1970's when Americans felt the tightening grip from oil-producing nations of the Middle East. It is the only project operating today that is tied to the Federal Nonnuclear Energy Research and Development Act of 1974, which was enacted to spur developments that could help the United States achieve energy independence.

The $2.1 billion plant began operating in 1984. Using the Lurgi gasification process, the synfuels plant gasifies lignite coal to produce valuable gases and liquids. The average daily production is 130 million standard cubic feet of synthetic natural gas(SNG), the majority of which is piped to Ventura, IA, for distribution in the eastern United States. The plant capacity is 170 million standard cubic feet. Many byproducts and alternate products are produced and marketed in the United States and worldwide including up to 1200 tons per day of anhydrous ammonia. A portion of the gas produced is used to make some of the byproducts.

The synfuels plant daily consumes about 18,500 tons of lignite supplied by the nearby Freedom Mine. The mine is owned and operated by the Coteau Properties Company, a subsidiary of the North American Coal Corporation.

THE GREAT PLAINS SYNFUELS PLANT PROCESS

The process of turning lignite into SNG begins by feeding 18,500 tons/day of sized coal to 14 Lurgi Mark IV gasifiers. In the Lurgi moving bed gasifiers, steam and oxygen are fed to the bottom of the gasifier and distributed by a revolving grate. The steam and oxygen slowly rise through the coal bed, reacting with the coal to produce a raw gas stream.

The raw gas stream that exits each gasifier is first cooled in a waste heat boiler that generates 100 psig saturated steam. After this initial cooling step, two-thirds of the raw gas is sent to additional waste heat recovery and cooling water unit where the gas is cooled to 95 degrees F. The remaining one-third of the raw gas is sent to shift conversion where the composition of the gas is modified by converting some carbon monoxide (CO) and water to carbon dioxide (CO_2) and hydrogen. The shifted gas is then cooled to 95 degrees F and combined with the cooled raw gas to make mixed gas.

The mixed gas stream is sent to the acid gas unit where CO_2 and sulfur compounds are removed by a cold methanol wash. Great Plains Synfuels Plant utilizes the Rectisol Process licensed by Lurgi. A liquid naphtha stream is also removed by the cold methanol wash. The naphtha stream can either be further treated and sold as a by-product or burned in the plant's main boilers as a liquid fuel. The synthesis gas from the Rectisol unit is then sent to Methanation where SNG is produced. Following Methanation, the SNG is compressed, dried and sent to the pipeline.

The Rectisol Unit also produces a waste gas stream. The waste gas stream is comprised primarily of the CO_2 and sulfur compounds removed from the mixed gas. The waste gas stream had been used as gaseous fuel in the plant's three main boilers. More recently this stream has been used as feed to the CO_2 compression unit. The waste gas stream only has a heating value of 50 Btu/SCF due to its high CO_2 content.

Gasification of lignite (which contains an average of 36 wt. % moisture) also produces a water stream called raw gas liquor. Raw gas liquor contains in part tars, oils, phenolic compounds, and ammonia. Raw gas liquor is condensed from raw gas and shifted gas at the various steps where these gases are cooled prior to the Rectisol Unit.

Raw gas liquor is first treated in the Gas Liquor Separation Unit where, through gravity separation, any tar, coal fines and tar oil are removed. The tar and coal fines are recycled back to the gasifiers. The tar oil is used as a liquid fuel in the main plant boilers.

The treated raw gas liquor from the Gas Liquor Separation Unit is further treated in two process units, Phenosolvan and Phosam, which remove crude phenolic compounds and ammonia. Stripped gas liquor from these two final treatment processes is sent to the plant's cooling tower as make-up water.

The crude phenol stream is further processed in a Phenol Purification Unit where pure phenol and cresylic acid are produced as saleable by-products. At times, depending on sales and purity, the product phenol is sent to the plant's main boilers and is burned as a liquid fuel.

In 1997 a 1000 ton per day CF Braun Ammonia Plant was relocated from Ft. Madison, Iowa and installed at the Great Plains Synfuels Plant. The Ammonia Plant is a conventional unit with the exception that it does not have a primary reformer. Synthesis gas from the Rectisol Unit is fed directly to the secondary reformer. Purge gas from the Ammonia Plant's synthesis loop is mixed with the fuel gas recovered from the gasification Unit going to the plant's main boilers.

The Great Plains Synfuels Plant has three Riley Stoker boilers and two C-E direct fired superheaters. The Riley boilers generate 1150 PSIG superheated steam. The superheaters take 1250 PSIG saturated steam produced in the Methanation Unit and Ammonia Plant and superheat the steam such that it can be combined with the 1150 PSIG steam.

The two superheaters use tar oil liquid fuel to provide the heat input required to superheat the 1250 PSIG steam. Flue gas from these two superheaters is used to reheat the flue gas scrubbed in the Flue Gas Desulfurization Unit.

KEY OPERATIONAL IMPROVEMENTS

The number of improvements over the course of operating the facility for nearly 20 years are many. Following are descriptions of some of the key improvements.

Increased Throughput

Shortly after start-up, the plant underwent a debottlenecking study to identify and correct rate limiting factors. The plant may now be operated at 127% of the original design capacity. It was determined that the gasifiers were most efficient when operated near design throughput. In order to optimize efficiency while maintaining high plant throughputs, the gasifiers have undergone significant mechanical improvements. Some of the key improvements include:

- Optimize water jacket thickness to prevent cracking.

- Modify oxygen distribution to minimize heat effects on gasifier jackets.
- Utilize hardened materials and weld overlay to improve valve seat life.

With these and many other improvements gasifier maintenance turnaround cycles have been extended by 30% to 40%.

Coal Blending

Good communication with the coal mine providing lignite provides advanced notification of upsets in coal quality. This allows the gasification operators to respond on a proactive basis. The range of coal quality that can produce good gas rates is wide. However, when the quality changes it takes time to find the optimum rate. The goal for coal blending is to provide constant quality feed.

Regulating the quality of coal by blending efforts at the mine reduces plant upsets by providing coal that is consistently suitable for efficient operations. Understanding the effects of different properties of coal on the gasification process has been developed since start-up of the facility. Knowledge has been gained to quantify the effects of these variables. Variables that have the largest effect on gasifier operation are sulfur, sodium and fines. Most often, primary coal blending efforts are to reduce sodium concentration, blending for sulfur is secondary.

<u>Sodium</u>
The most important aspect of operating the gasifiers is operating the combustion zone at the ash melting point. The ash fusion temperature fluctuates as the sodium concentration changes, in turn steam rates and/or grate speed have to be adjusted. The coal mine blends coal to provide a constant composition of 6-8% sodium in the coal to the gasifiers. Higher than normal sodium concentration, from 8% to 13%, lowers the ash fusion temperature. Low fusion temperature can result in a large formation of fused ash or clinkers in the ash bed. DGC has experienced formation of clinkers that filled 20% of the gasifier. The gasifier has to be shutdown and jackhammers used to break up the clinker so it can be removed.

<u>Sulfur</u>
High sulfur levels cause environmental concerns. With the addition of the Flue Gas Desulfurization unit the environmental impact of high sulfur concentrations has been eliminated.

<u>Fines</u>
The gasifiers cannot tolerate coal feed with a high fines concentration. The design limit is for a maximum of 5% coal less than 1/4 inch in size. The cause of high fines concentration is usually a result of one of the following:

- Wet coal that does not screen efficiently.
- Plugged coal screens.
- Aged/Brittle Coal.

When conditions are right, high fines, damp coal, and high top flange temperatures, the gasifiers tend to flash. Flashing possibly occurs because of the oxygen in air that enters the coal locks along with the coal. Flashing causes carry over of solids along with the raw gas. This can result in plugged downstream equipment and/or a gasifier trip on high top flange temperature. It is also anticipated that higher concentrations of fine coal will cause channeling in the bed and carry over of fines to downstream equipment. If an over concentration of fines is allowed to enter a gasifier in the coal feed, the operator has no recourse but to reduce gas production. Such a condition, if allowed to continue, will require a total gasifier rate reduction with disruption of the entire plant operation.

ODOR REDUCTION / ENVIRONMENTAL EMMISSIONS ISSUES

Flue Gas Desulfurization

In the original design of the Great Plains Synfuels plant a Liquid Redox Sulfur Recovery Unit (SRU) was included to remove hydrogen sulfide from a waste gas stream before this stream was burned in the plants boilers. Following start up and initial operation of the plant, the SRU was found to be unable to remove the required amount of hydrogen sulfide from the waste gas. So the sulfur dioxide content in the plant's flue gas emitted from the main stack did not meet the permitted levels. Numerous changes in operation of the SRU, changes in design and changes in chemistry, were unsuccessful in improving the hydrogen sulfide removal to the level required to meet the sulfur dioxide permit.

In late 1990, DGC commissioned a task force to review all possible options and recommend a solution to meet the environmental permit. Options of treating the waste gas to remove hydrogen sulfide prior to burning the gas in the boilers were investigated along with flue gas desulfurization (FGD). The Task Force found that a wet limestone forced oxidation FGD for the flue gas from the Plant's three main boilers was the best solution.

During the Task Force review process, General Electric Environmental Systems Inc. (GEESI) approached DGC to discuss their ammonia scrubbing technology. This technology was of interest to DGC as it would produce ammonium sulfate. This could then be sold as fertilizer rather than producing gypsum, which would be a waste for disposal in the ash disposal area. This fit into the attempt to enhance by-product production at the Great Plains Synfuels Plant to reduce the reliance on SNG sales.

DGC and GEESI entered into a joint venture to build and test a 10,000 ACFM Ammonium Sulfate Forced Oxidation FGD pilot plant using flue gas from one of the main plant boilers. The pilot plant was first operated using limestone as a reagent to gather operating data on the liquid to gas ratio (L/G) and removal rates as well as other data for scale up purposes. The pilot plant was then operated using ammonia as the reagent at various levels of SO_2 in the flue gas to simulate concentrations that the commercial scale unit would see.

Following successful completion of the ammonia scrubber pilot plant, DGC continued the process of requesting bids for a limestone forced oxidation FGD. An alternate bid from GEESI for an ammonium sulfate forced oxidation FGD was accepted for review. Following review of all bids, DGC and GEESI entered into an agreement to build the first commercial scale Ammonium Sulfate Forced Oxidation FGD.

Construction of the Ammonium Sulfate Forced Oxidation FGD was completed in June 1996. Several difficulties had to be overcome during the initial operation of the new FGD. The FGD has shown it can remove sulfur dioxide and produce a saleable grade of ammonium sulfate fertilizer.

Wet Electro-Static Precipitator
While the FGD unit succeeded in allowing the plant to meet state required sulfur dioxide regulations, the opacity of the stack emissions was high. The particulate emissions from the FGD system are above permissible levels, making the plume an unattractive environmental feature.

To improve the situation, a Wet Electrostatic Precipitator (WESP) is being added to further process the flue gas. The WESP is designed to remove microscopic particulate matter that add to the cloudy appearance of the stack's plume. The WESP takes flue gas from the FGD and passes it through a series of collecting and discharge electrodes. A high negative DC voltage is applied to the discharge electrodes. The flue gas around the discharge electrodes is ionized, creating both positively and negatively charged ions. The positive ions travel to the negative discharge electrode and are not a contributor to the operation or performance of the precipitator. The negative ions are attracted to the "positive" collecting electrode. The mist and dust particles in the flue gas are charged by the negative ions flowing between the discharge electrodes and the collecting electrodes. The electrostatic field then drives the now negatively charged mist and dust particles to the collecting electrodes. The collected particles are removed from the collecting electrodes by washwater sprays.

Plant Odor Control
An undesirable byproduct of lignite gasification is the formation of odorous organic sulfur compounds and nitrogen compounds. DGC has worked diligently to identify and eliminate fugitive emissions and odorous vent streams. However, the plant's cooling tower, which is fed process water streams, continues to be the most significant odor source.

A consultant was hired to study the odors in the cooling tower and determine the sources. The superstill overhead condensate stream was determined to be the worst single odorous stream. DGC is proceeding with a multi-million dollar project to design, construct and install two packed towers to air strip volatile and malodorous contaminants from this water stream. This is being done to improve the water quality before it is used as makeup for the cooling tower. The offensive stream is produced as a distillate from the Superstill in the Phosam Ammonia Recovery Unit. It contains part-per-million concentrations of both ammonia and miscellaneous nitrogen-containing organic compounds ("nitriles"). The second column will scrub the sour air leaving the stripper (first column) to preferentially recapture the ammonia. The spent air will then be piped to the three Riley boilers, where the organic vapors will be combusted.

During the summer and fall of 1998 a fairly extensive pilot plant investigation was conducted to air-strip the SSOH condensate and test the odor reduction potential of the process. The first column used air, steam and heat to remove the "nitriles" (propylnitrile, acetonitrile, pyridine, and pyrrole, although the latter two aren't actually nitriles), a portion of the ammonia, and a variety of unidentified compounds from the process water. The second column used an ammonium phosphate solution to selectively and chemically absorb the ammonia from the exhaust air of the first tower. This combination of stripper and absorber was investigated with the commercial goal of reducing the amount of ammonia going to the boilers. This was felt necessary to lessen the probability of raising the boiler nitrogen oxide emissions when the vapors are combusted. Prior to entering the boilers, the spent air will combine with a similar vapor stream and pass through a knockout drum to remove any entrained liquid or condensate.

KEY PLANT ADDITIONS

Anhydrous Ammonia

The Great Plains Synfuels plant had been recovering a small amount of anhydrous ammonia from the gasification process and marketing it as an agricultural fertilizer since the plant's startup. Production was about 25,000 tons per year. Early in 1994 several factors prompted the idea for increasing anhydrous ammonia production:

- Good market for anhydrous ammonia in 1994.
- Falling natural gas prices.
- Need for more anhydrous ammonia to feed the FGD scrubber.
- Feed gas was available. Primary reformer not needed.
- Plant located in an agricultural region.

DGC opted to purchase an existing anhydrous ammonia plant at Fort Madison, Iowa. This was done to get the facility on line quickly and take advantage of the favorable market as well as feed the new scrubber. Compared to a new plant cost, it was projected to be a much lower investment.

The plan called for increasing the 1000 ton per day Braun ammonia plant to 1200 tons per day and have it on-line in 3 years. The construction objectives were met. But the start-up and initial operation had many challenges associated with old or poorly refurbished equipment. Currently, the ammonia unit is capable of achieving 1200TPD production rates, and the reliability is improving.

Carbon Dioxide For Enhanced Oil Recovery

The idea for selling carbon dioxide from the Great Plains Synfuels plant arose well before the plant was built in the early 1980's. The focus was to use carbon dioxide from the plant for injecting into aging oil fields and recovering oil that otherwise would be lost. In particular, enhanced oil recovery using carbon dioxide from Great Plains Synfuels plant would make economic sense for certain reservoirs within the huge Williston Basin field underlying parts of North Dakota, South Dakota and Montana in the United States and Manitoba and Saskatchewan in Canada.

In the process of producing SNG from lignite, carbon dioxide and hydrogen sulfide must be removed from the gas. This is done in the Rectisol unit. Low temperature methanol wash is used to remove the carbon dioxide and hydrogen sulfide from the raw gas before it enters the Methanantion Unit for further processing. The methanol is regenerated for reuse by flashing it from 400 psig to sub-atmospheric pressure. As the pressure is reduced carbon dioxide, hydrogen sulfide, and a small amount of hydrocarbons are released. This is the feed gas to the carbon dioxide compression unit. There is a total of 240 MMSCFD of carbon dioxide available and current sales are for 95 MMSCFD. Before the carbon dioxide Compression Unit was built, the carbon dioxide was sent to the boilers to recover the small percentage of hydrocarbons and thermally convert hydrogen sulfide to sulfur dioxide. The feed gas to the carbon dioxide unit was a low value fuel, and has now become a source of revenue.

The compression unit consists of two 8-stage compressors manufactured by GHH Borsig. Each compressor is driven by a 19,500 Hp fixed speed motor. Between each stage air cooled heat exchangers are used for cooling. These compressors take feed gas at 3 psig and compress it to 2700 psig. 205 miles of 14” and 12” pipe carries the gas from the plant to the Weyburn oil field located in Southern Saskatchewan. The new compressor and pipeline system began operation in the fall of 2000. Since that time DGC has been working with the customer (Pancanadian Resources of Calgary, Alberta) to achieve reliable operation. The compressors have achieved the design throughput, and the customer is beginning to experience the benefits of tertiary recovery of the aging oil field.

A sophisticated computer model of the pipeline monitors pipeline pressures, temperatures, and flow rates to identify potential leaks in the pipeline. Pressure and temperature readings are taken at each of 12 valve stations along the pipe and sent via microwave, hard wire, and radio communication to a control room at the Great Plains Synfuels plant. The software uses this information to identify a potential leak. The software can identify a potential leak location to within +/- two miles, estimate the leak rate and report the total volume lost.

FUTURE

DGC’s bottom line is significantly dependant on a single commodity (methane). Commodities are known to have significant price variability, leading to exposure to varying degrees of financial risk based on the then current price of the single product. DGC will continue to reduce