End-Use Technology Study – An Assessment of Alternative Uses for Associated Gas

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END-USE TECHNOLOGY STUDY – AN ASSESSMENT OF ALTERNATIVE USES FOR ASSOCIATED GAS

ABSTRACT

The Energy & Environmental Research Center (EERC) in partnership with the North Dakota Industrial Commission Oil and Gas Research Council, Continental Resources, and the U.S. Department of Energy National Energy Technology Laboratory conducted a study focused on assessing the technical and economic viability of technologies and processes that could lead to increased utilization of associated gas. The impetus for this study was derived from the rapid growth of gas flaring in North Dakota, itself a function of rapid increase in oil production. This final report summarizes EERC assessments of distributed end-use opportunities that were evaluated for their potential to contribute to significant reductions of gas flaring in liquids-rich shale formations like the Bakken Formation in North Dakota.

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NOMENCLATURE

AEGS	Alberta Ethane-Gathering System
ASHRAE	American Society of Heating, Refrigeration, and Air Conditioning Engineers
bbl	barrel
bcf	billion cubic feet
BEPC	Basic Electric Power Cooperative
bpd	barrels per day
Btu	British thermal unit
CARB	California Air Resources Board
CFR	Code of Federal Regulations
CHP	combined heat and power
CNG	compressed natural gas
DEG	diethylene glycol
DOE	U.S. Department of Energy
ECBC	Edgewood Chemical Biological Center
EERC	Energy & Environmental Research Center
EIA	U.S. Energy Information Administration
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FPP	factory protection plan
ft^3	cubic foot
GGE	gasoline gallon equivalent
GOR	gas-to-oil ratio
GRI	Gas Research Institute
HHV	higher heating value
JT	Joule–Thompson
kWh	kilowatt-hour
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LTS	low-temperature separation
Mbpd	thousand barrels per day
Mcf	thousand cubic feet (standard conditions)
Mcfd	thousand cubic feet per day
MDU	Montana–Dakota Utilities Co.
MMbpd	million barrels per day
MMcf	million cubic feet
MOF	metal organic framework
MTBE	methyl tertiary butyl ether
MW	megawatt
NBIP	Northern Border Interstate Pipeline
NDDMR	North Dakota Department of Mineral Resources
NDIC	North Dakota Industrial Commission
NETL	National Energy Technology Laboratory

NGL	natural gas liquid
NGV	natural gas vehicle
NREL	National Renewable Energy Laboratory
O&M	operating and maintenance
OEM	original equipment manufacturer
OGD	Oil and Gas Division
OGRC	Oil and Gas Research Council
PA	propane–air
RLOS	refrigerated lean oil separation
SAE	Society of Automotive Engineers
scf	standard cubic foot
TEG	triethylene glycol
ton	short ton (2000 pounds)
USGC	U.S. Gulf Coast
VMT	vehicle miles traveled
WBIP	Williston Basin Interstate Pipeline
WTI	West Texas Intermediate

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EXECUTIVE SUMMARY

The Energy & Environmental Research Center (EERC), in partnership with the North Dakota Industrial Commission (NDIC) Oil and Gas Research Council (OGRC), Continental Resources, and the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL), has conducted a study focused on assessing the technical and economic viability of technologies that could increase utilization of associated gas. The impetus for this study is the rapid growth of gas flaring in North Dakota, a function of rapid increase in oil production. The stranded gas resource is a transient resource, permitted by the state to be flared for up to 1 year, changing in quantity and location as oil wells begin production and gas-gathering infrastructure gets constructed, thereby creating a challenge to mating an end-use technology to the resource.

The intent of this study is to examine technologies that can utilize the associated gas at locations upstream of traditional natural gas-processing plants, thereby extracting value from a currently uncaptured resource. Economic analysis of these technologies consisted of comparing capital expenses to potential revenue generation in an effort to frame the potential for more detailed economic study specific to individual technology. Technologies evaluated included 1) natural gas liquid (NGL) recovery, 2) compressed natural gas (CNG) for vehicle fuel, 3) electrical power generation, and 4) chemical production.

Bakken associated gas is typically low in sulfur and high in NGLs, creating both unique challenges to utilization and economic opportunity since NGLs are currently more valuable than the dry NG. Deploying small-scale NGL recovery systems as an interim practice while gathering lines are built allows the highest value and most easily transported hydrocarbons to be marketed. Further, the leaner gas generated from these systems can be more easily utilized for power, transportation fuel, or transported as a compressed gas. Clearly, NGL recovery would be most economical at wells flaring larger quantities of gas, immediately after production begins to capture the greatest volume of gas. Additionally, technology mobility is critical to enable relocation to new wells as gas-gathering infrastructure is constructed.

While there may be several other drivers to warrant the use of CNG in the Bakken region, economics alone will most likely not justify conversion of medium-sized fleets of vehicles to CNG if a distributed CNG refueling approach is taken. Bakken associated gas is too rich with NGLs and too variable in composition to be used "as-is" in NG vehicles (NGVs). It must be purified to a strict specification and compressed before being dispensed to a vehicle. Further, vehicle fleets utilizing the CNG fuel would need to be adaptable and flexible to take advantage of this stranded and transient gas resource. In spite of these drawbacks, U.S. Energy Information Administration (EIA) data indicate that CNG prices have been significantly lower and experienced less volatility over the past decade when compared to gasoline and diesel fuels, and the price gap is expected to continue through 2015.

The demand for power in the Williston Basin has grown rapidly. In addition to meeting this growing demand, utilities are also faced with ensuring grid reliability. Forecasts suggest a

tripling of the electric load in oil-producing areas of western North Dakota and eastern Montana. An initial review of the characteristics of each distributed power generation technology eliminated some options from further consideration. Based on this review, three technologies were evaluated: reciprocating engine, gas turbine, and microturbine. When evaluating power generation scenarios, the projects were characterized into two distinct categories based on the primary use of the electricity, grid support and local power. In general, power production using rich associated gas is a viable option. A wide variety of power generation technologies exist that can, without much difficulty, utilize rich gas of varying quality to produce electricity and are scaled to wellhead flow rates.

The petrochemical industry is dominated by large processing plants where economy of scale and access to large gas fields maximize profitability. Despite rapid and significant growth of gas production in North Dakota, only a small fraction of total U.S. NG is produced in the state. Pipeline and rail export of gas and NGLs to existing petrochemical infrastructure is likely to continue to be the predominant mode to market these resources. Although NG export is likely to dominate in North Dakota, opportunity does exist for small-scale technologies that can convert low-cost gas to higher-value chemicals or fuels that have a strong regional demand. The production processes with the best opportunity for economic success at the well site include novel fertilizer production technologies or innovative gas-to-liquid approaches that can be scaled appropriately. All such processes would benefit by being mobile to periodically relocate to better-producing wells and avoid reduced utilization rates.

Although none of these approaches appear to be highly compelling from a purely economic perspective, two end-use technologies were identified that represent technically feasible applications: CNG and power production. The high price of transportation fuel relative to CNG creates some advantages; however, rich gas cannot be used in standard NGVs because of concerns over emissions and engine performance. In the case of power production, these technologies match nicely the scale and temporal nature of the associated gas resource. In either case, small-scale NGL recovery, although less efficient than at large centralized facilities, may be an enabling technology, allowing value to be extracted from the associated gas while improving economical utilization of leaner gas for transportation and power. Chemicals production would be the most challenging to deploy at small scale in the Williston Basin, but some chemicals (specifically nitrogen-based fertilizers) may hold some promise.

Table ES-1 is a summary of the end-use technologies evaluated and their respective characteristics as they relate to deployment in the Williston Basin.

Table ES-1. Summary of Evaluated Technologies with Qualitative Characteristics

Technology	Gas Use Range, Mcfd	NGL Removal Requirement	Scalability to Resource	Ease of Mobility	Likelihood of Deployment at Small Scale
Power – Grid Support	1000–1800	Minimal	Very scalable	Very easy	Very likely
Power – Local Load	300–600	Minimal	Very scalable	Very easy	Very likely
CNG	50+	Yes	Scalable	Very easy	Possible
Chemicals	1,000,000*	No	Not scalable	Not mobile	Very unlikely
Fertilizer	300–2000	No	Scalable	Not easy	Possible
Gas-to-Liquids	1,000,000*	No	Scalable	Easy	Possible

* Typical commercial-scale plant.

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INTRODUCTION

The Energy & Environmental Research Center (EERC), in partnership with the North Dakota Industrial Commission (NDIC) Oil and Gas Research Council (OGRC), Continental Resources, and the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL), has conducted a study to assess the technical and economic viability of technologies and processes that could lead to increased utilization of associated gas. The scope of this study included evaluating distributed end-use opportunities that may benefit from the rapid expansion of oil and gas production in shale formations like the Bakken Formation in North Dakota.

In North Dakota, oil production increased to 534,000 barrels per day (bpd) by the end of 2011, up twofold in only 2 years. This rapid growth in oil production has led to an increase in the amount of associated gas that is flared while gas-gathering, processing, and transmission infrastructure are built to accommodate the new production. In spite of dramatic investment and expansion of gas-processing infrastructure, around 30% of North Dakota's produced natural gas is flared, nearly 190,000 thousand cubic feet (Mcf)/day or 1,500,000 gasoline gallon equivalent (GGE)/day.

This gas resource, although underutilized, is not a low-value by-product of oil production. Bakken shale gas is rich in natural gas liquids (NGLs). Therefore, although natural gas prices are at a historic low—approximately 10% of the value of crude oil on an energy-equivalent basis—the high concentration of NGLs, ethane, propane, butane, and higher-carbon-number hydrocarbons, supports the economic push to gather and process gas. Typical Bakken gas may contain as much as 10 gallons of NGLs per 1 Mcf of wellhead gas. These NGLs, when recovered from the gas during gas processing, provide economic incentive to build the necessary infrastructure to prevent flaring.

North Dakota, a rural state, possessed limited NG infrastructure prior to the recent increase in oil and gas production activity. Construction of gas-gathering pipeline, gas-processing plants, and interstate pipeline is proceeding rapidly, with industry planning to invest $3 billion between 2011 and 2014. For a period of time, gas flaring is likely to continue; however, it is widely expected that as production activities mature in the Bakken play, gas gathering and infrastructure will meet the demand. Currently the North Dakota Century Code allows gas to be flared for up to 12 months after initial production. After that, gathering piping is expected to be connected to new well sites, and gas must be marketed. Nonetheless, an opportunity exists for the next several years to utilize newly produced, otherwise flared associated gas before gathering infrastructure is fully built out. Longer term, opportunity will continue because of the existence of a small fraction of wells that, because of geography or economics, may not be connected to gas-gathering systems.

The expectation of the study when proposed was to evaluate a number of known technologies and assess their applicability to distributed operation with associated gas containing high levels of NGLs. Specific applications that were considered included 1) transportation fuel either with compressed natural gas (CNG) or liquefied natural gas (LNG), 2) power production for distributed electrical loads and electrical grid support, and 3) gas and NGL conversion to chemicals and fuels. In addition to these primary end uses, other technologies were investigated that could have a direct effect on reducing the amount of gas going to flare. It was not the intent of this study to complete an economic assessment of traditional, large-scale petrochemical industry expansion into North Dakota. The North American petrochemical industry is mature and rapidly transforming existing infrastructure to adapt to the dramatic shift toward shale gas production in the Marcellus, Eagle Ford, Bakken, and other shales. Recognizing the logistical challenges of utilizing associated gas at the well site, additional consideration was given to novel implementation of technology that could create additional demand for NG in North Dakota.

BACKGROUND ON BAKKEN ASSOCIATED GAS

Geographic Discussion

Named for the town located in its center, the Williston Basin is a large, oval-shaped depression several hundred thousand square miles in area, underlying parts of North Dakota, South Dakota, Montana, and the Canadian provinces of Manitoba and Saskatchewan. Within the Williston Basin is the recently exploited Bakken Formation, an oil–wet shale formation approximately 200,000 square miles in area. The location of the Bakken Formation is shown in Figure 1.

Figure 1. Geographic extent of the Bakken Formation within the Williston Basin.

Geologic Discussion

The Bakken Formation is known to be an important source rock for oil in the Williston Basin. The formation typically consists of three members: the upper and lower members, comprising shales, and the middle member, comprising dolomitic siltstone and sandstone. Total organic carbon (TOC) within the shales may be as high as 40%, with estimates of total oil in place across the entire Bakken Formation ranging from 10 to 500 billion barrels (bbl) (Figure 2). While the hydrocarbon resource within the Bakken Formation is tremendous, the Bakken is considered an unconventional oil play because it is typically characterized by very low porosity and permeability.

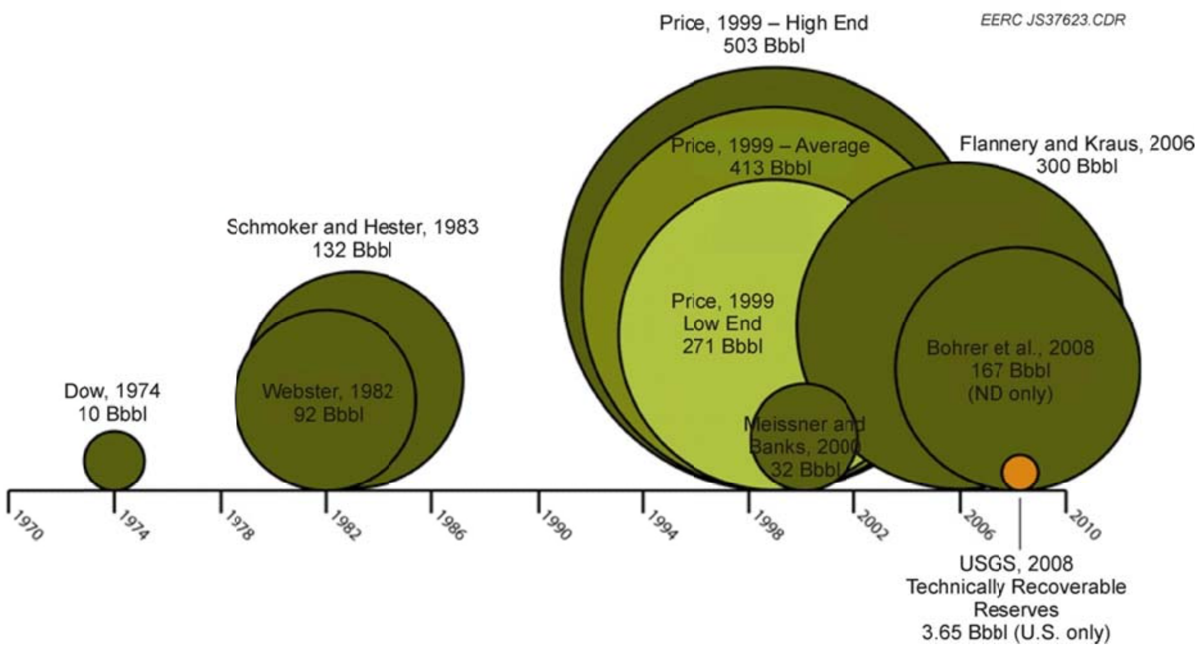


Figure 2. Historical estimates of Bakken oil resources (Bohrer et al., 2008).

The Associated Press announced on October 28, 2009, that North Dakota had become the fourth largest producer of oil in the United States, ahead of Louisiana and Oklahoma, with the top three being Texas, Alaska, and California, respectively. North Dakota produced more than 15 million bbl (510,000 bpd) in November 2011 (North Dakota Department of Mineral Resources Oil and Gas Division, 2012). Based on the increased production, North Dakota became the No. 2 producer of oil in the United States in March 2012, surpassing California and Alaska. In addition to the 15 million bbl of oil, approximately 15.6 million cubic feet (MMcf) of NG was produced in November 2011. An important point regarding the Bakken Formation is that, although a shale formation, it is an oil play (with associated NG), unlike many of the other shale formations in the United States, which tend to be primarily NG plays.

The Bakken Formation in the U.S. portion of the Williston Basin underlies most of western North Dakota and northeastern Montana. The formation is productive in numerous reservoirs throughout Montana and North Dakota, with the Elm Coulee Field in Montana and the Parshall and Sanish Fields in North Dakota being the most prolific examples of Bakken success.

The Bakken Formation has been known to be hydrocarbon-bearing in the Williston Basin since the 1950s, with each decade since the 1970s seeing periods of interest among oil producers as oil recovery strategies and technologies evolved. As such, the stratigraphic, lithological, and structural characteristics of the Bakken Formation in North Dakota have been the subject of many studies.

With respect to stratigraphy, the Devonian–Mississippian-aged Bakken Formation in the Williston Basin typically comprises three members: the upper, middle, and lower Bakken (Figure 3). Lithologically, the upper and lower members of the Bakken Formation are dominated by shales rich in organic carbon that act as the source rock for oil reservoirs in the middle Bakken. The lithology of the middle Bakken varies widely from clastics (including shales, silts, and sandstones) to carbonates (primarily dolomites), with five distinct lithofacies being identified in the North Dakota portion of the Williston Basin.

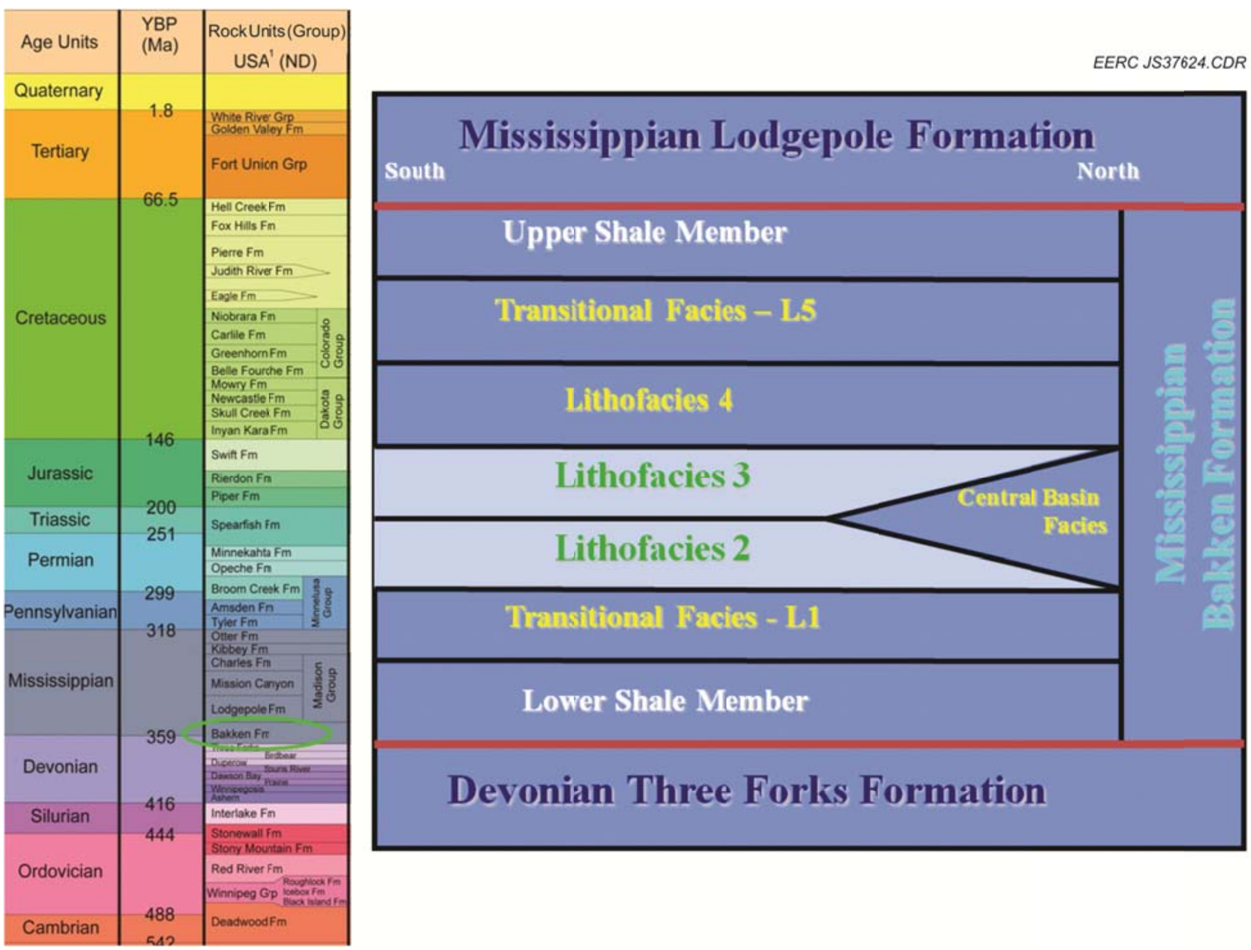


Figure 3. Stratigraphic column for rocks of the Williston Basin in North Dakota and generalized stratigraphy of the Bakken Formation in North Dakota.

Although the Bakken Formation is the target of the majority of the current oil production activity, the petroleum industry is also optimistic about several others, including the Tyler, Lodgepole, Three Forks, and Birdbeard Formations.

Current Oil and Gas Production

Exploration and Production Technology

In general, approaches to the selection of exploitation strategies and application of technologies and tools for the drilling, completion, and stimulation of wells in the Bakken play have been largely dictated by knowledge (or lack thereof) of lithology, structure, and geomechanical properties within a localized area. A vast majority of Bakken wells in the last several years have been drilled horizontally into the middle member where geology is thought to be most favorable (e.g., areas of relatively higher porosity and permeability). For most Bakken wells, the use of hydraulic fracturing is critical to establishing long-term productivity.

Well completions consist of horizontally drilled wells at depths greater than 8000 ft and lateral lengths of 5000–10,000 ft. Completions include openhole and variations of cemented and uncemented liners, shown in generalized depictions from North Dakota Department of Mineral Resources – Oil and Gas Division (NDDMR–OGD) well files in Figures 4–6.

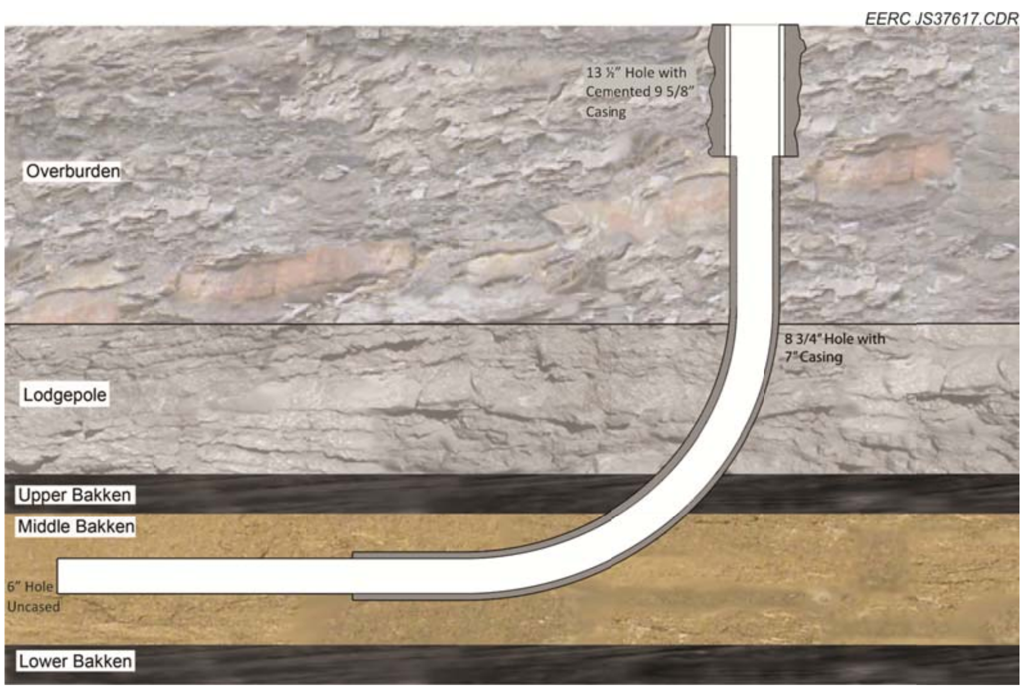


Figure 4. Generalized depiction of an open-hole completion in the middle Bakken, based on well completion diagrams in NDDMR–OGD well files.

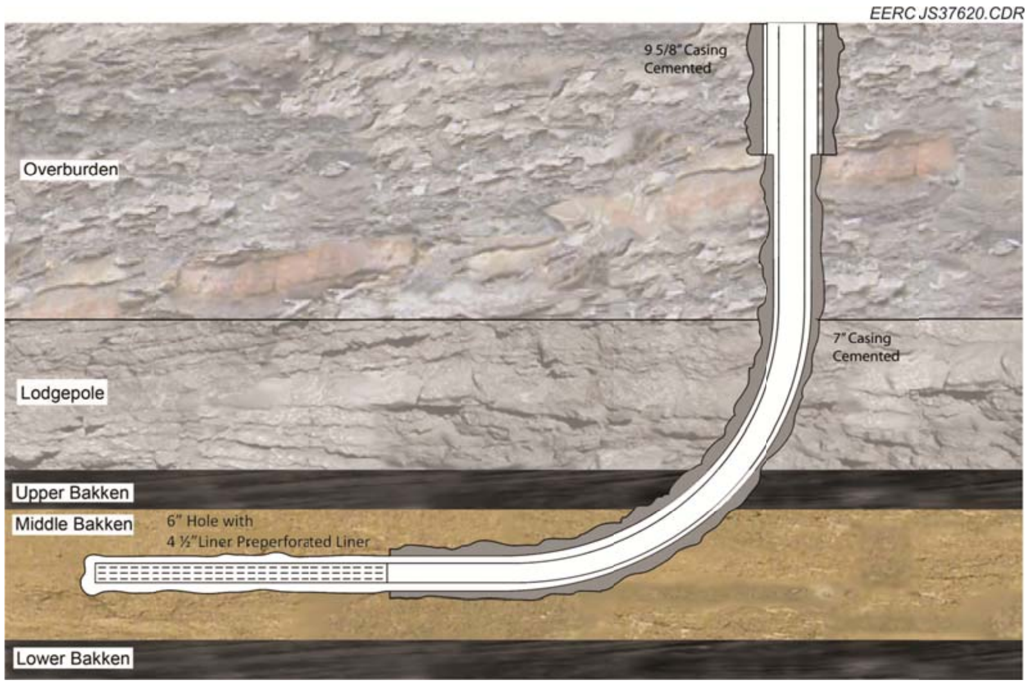


Figure 5. Generalized depiction of a Middle Bakken uncemented liner completion, based on well completion diagrams in NDDMR–OGD well files.

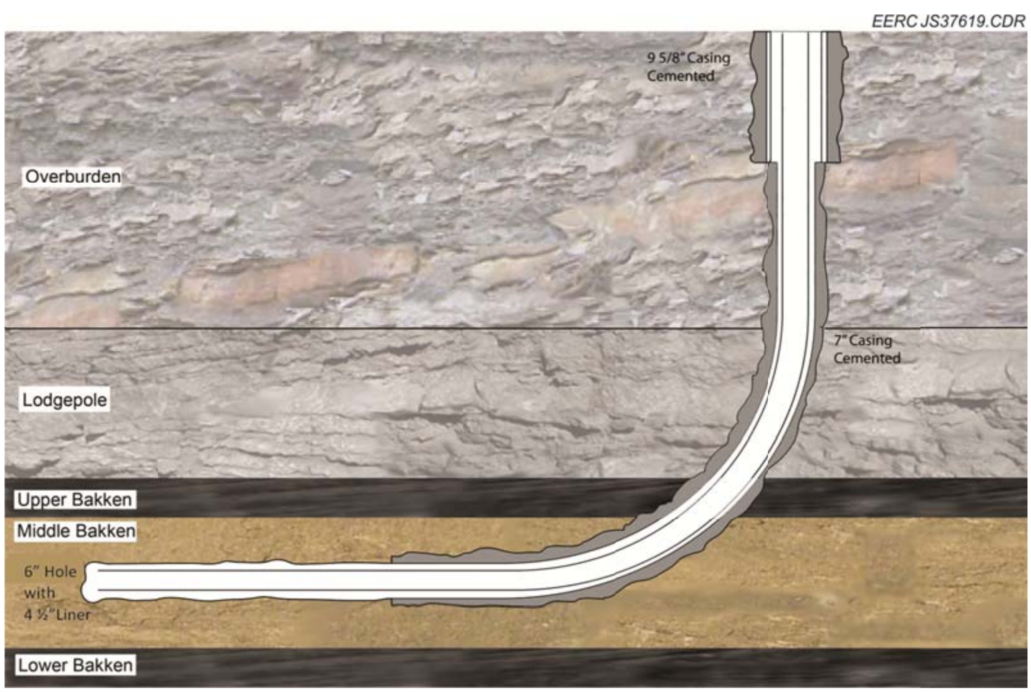


Figure 6. Generalized depiction of a cemented liner completion in the middle Bakken, based on well completion diagrams in NDDMR–OGD well files.

Fracture treatments can be divided into two categories: single stage or multistage. Single treatments in openhole completions have lower capital costs than multistage fracture completions; however, multistage completions appear to be increasing in popularity among most operators.

Figure 7 shows a generalized wellbore schematic of a multistage treatment scheme using swell packers to isolate the various fracture zones. The objective of a single-stage completion is to fracture the well along the length of the wellbore in order to create the greatest contact area between the fracture and the wellbore. Multistage completions attempt to create fractures transverse to the wellbore and, unlike longitudinal fracture completions, require quality proppant and proppant placement to ensure good flow communication to the wellbore.

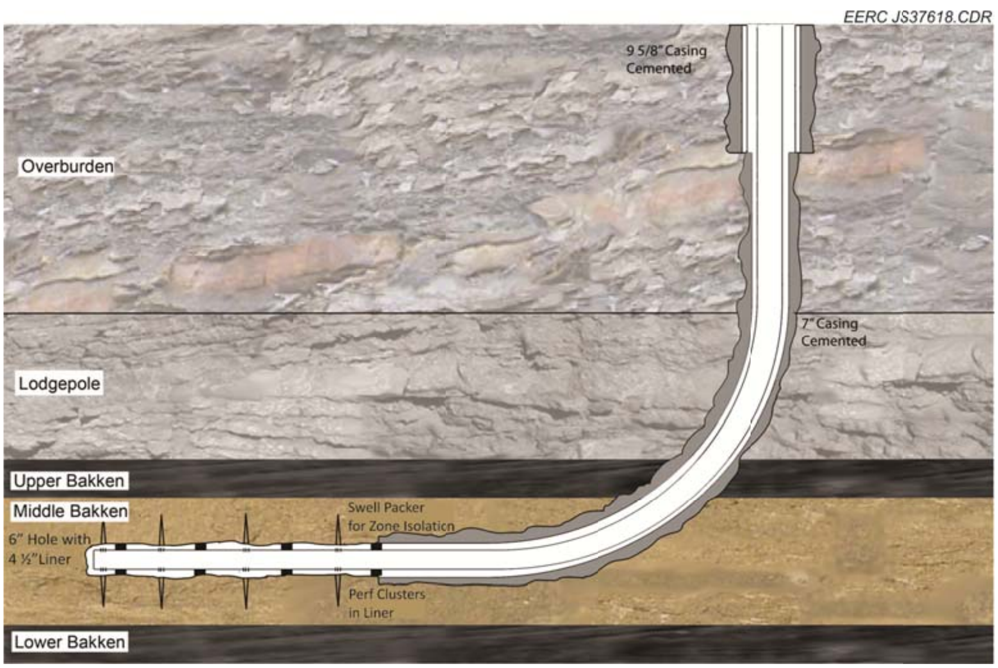


Figure 7. Generalized wellbore schematic showing the placement of swell packers for a multistage fracture treatment, based on well completion diagrams in NDDMR–OGD well files.

Oil and Gas Production

Since 1951, when oil was first produced from the Williston Basin, oil has been produced at a relatively slow pace. With the advent of horizontal drilling (first utilized in the Williston Basin in the late 1980s) and hydraulic fracturing or “fracking” (first utilized in the Bakken Formation in the mid 2000s), the efficiency of oil recovery improved and made recovery of oil from unconventional formations such as the Bakken economical. Figure 8 shows the annual oil production in North Dakota from 1951 through 2011.

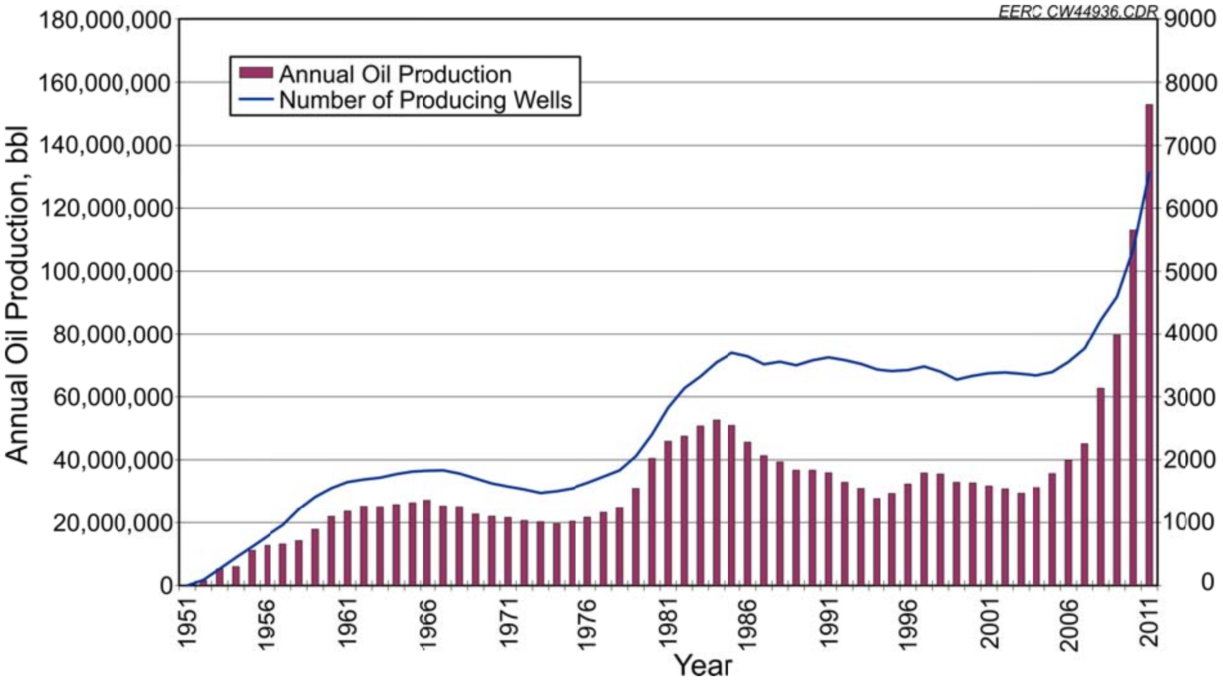


Figure 8. Annual oil production and number of wells producing in North Dakota from 1951 through 2011. Data sourced from the North Dakota Industrial Commission, Oil and Gas Division.

Daily oil production has increased significantly, exceeding 500,000 bpd (recording a new high of 534,000 bpd in December 2011) and is projected to continue rising, although the rate of increase is uncertain. The number of producing wells and active drilling rig counts also surpassed significant milestones in 2011, exceeding 6300 and 200, respectively, in November 2011.

The Bakken Formation, although an oil play, also produces significant quantities of associated NG, and the quantities of NG produced have also increased with the growing oil production. Daily gas production reached an all-time high in December 2011, exceeding 540,000 thousand cubic feet (Mcf) per day. The annual production for 2011 was also a new record, with 155,803 MMcf produced. Figure 9 shows the annual oil and gas production since 1951 and 1990, respectively. Gas records prior to 1990 are incomplete.

Interestingly, the basinwide gas-to-oil ratio (GOR) production has gone from 2:1 historically to 1:1 most recently. Despite the change in this ratio, the quantity and pace of new oil (and gas) production has resulted in a substantial shortage of gas-gathering and processing capacity. The shortage of gas-processing capacity, in turn, has resulted in a dramatic increase in gas being flared at the well site. Therefore, the industry is investing considerable capital in gas-gathering and processing infrastructure to capture this gas resource, but at the current price of NG, the economics are challenging. State officials have released statements indicating that their goal is to see industry get flaring down to at least 10%. For the purposes of this study, this "stranded" gas is being called nontraditional NG, a term that is intended to describe all NG that is upstream of the gas-processing facility.

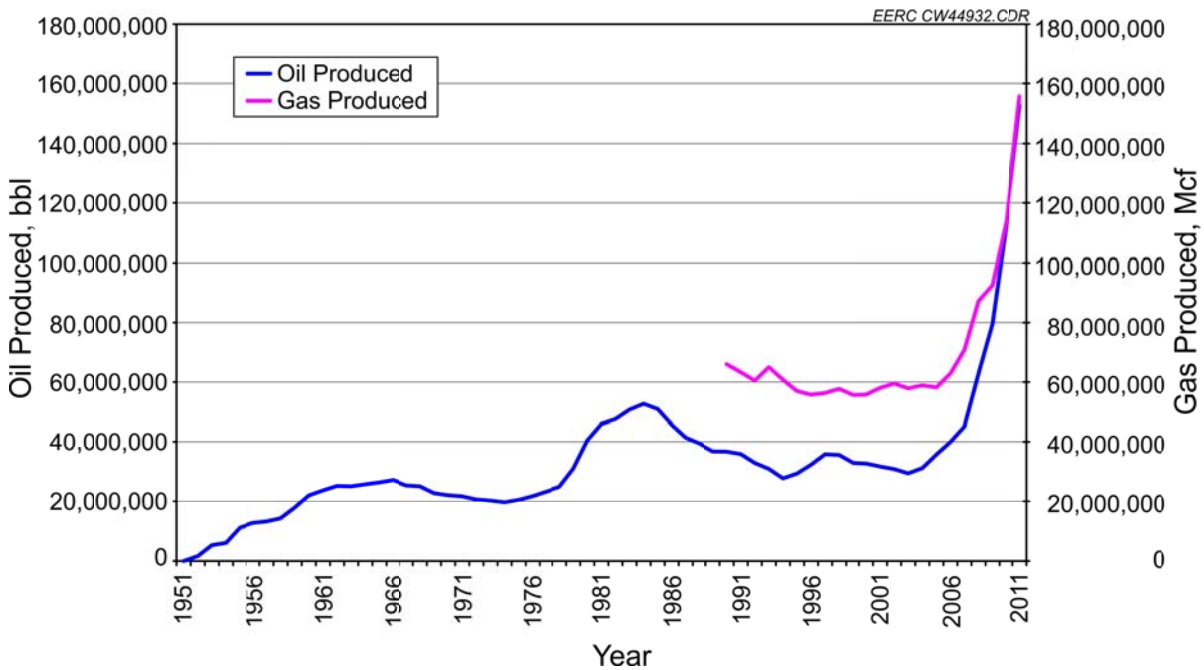


Figure 9. Annual oil and gas production in the Bakken Formation. Data sourced from the North Dakota Industrial Commission, Oil and Gas Division.

Data through the end of 2011 were compiled from NDDMR–OGD regarding the quantity of the NG resource and are considered primarily from the Bakken Formation. More accurately, 70% comes from the Bakken Formation, 12% from the Madison Formation, and the remaining 18% (none more than 3%) from several other formations. Focusing on the Bakken Formation in North Dakota only, the top four oil- and gas-producing counties are Dunn, McKenzie, Mountrail, and Williams (in alphabetical order). Table 1 summarizes the December 2011 oil and gas production from these four counties.

Table 1. December 2011 Monthly Oil and Gas Production for the Top Four Producing Counties in North Dakota

County	Monthly Oil Production, bbl	Monthly Gas Production, Mcf
Dunn	2,337,900	1,620,249
McKenzie	3,079,265	4,343,047
Mountrail	4,497,997	3,256,932
Williams	2,053,172	3,273,668

To better understand the location of this gas production, a graphical depiction was created to show the geographic location of gas production as well as the location of flared gas based on the December 2011 data from NDDMR–OGD (Figure 10). For each of these figures, a 5000- × 5000-meter grid was applied, and gas volumes (total and flared) were summed within each grid

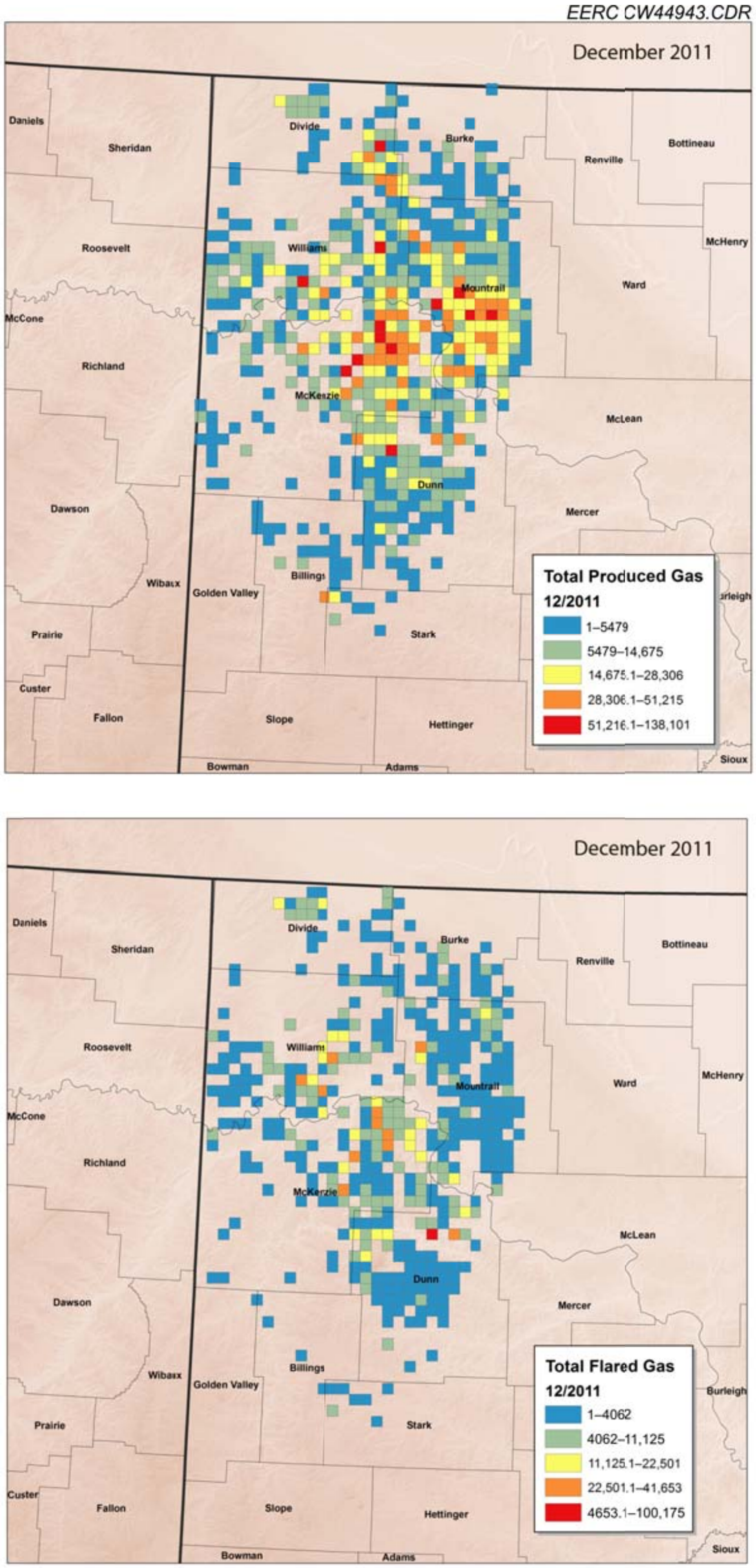


Figure 10. Graphical depiction of total gas produced and total gas flared for December 2011.

for December 2011 in Mcf. The aggregate for each grid was then represented in each grid by color corresponding to a volume range. These two figures make clear some important points about the issue of NG flaring at the well site:

- Flaring is widespread throughout the Williston Basin.
- Higher levels of flaring exist where gas gathering has not yet been built out.

A chart of the annual gas produced, gas sold, and gas unsold since 1990 shows the significant increase in gas production as well as the increase in unsold gas (Figure 11). The percentage of gas unsold (and assumed flared) at the end of 2011 reached a new high, exceeding 35% of the total gas produced. Figure 12 provides a graphical perspective on how the percentages of gas sold and unsold have changed with the development of the Bakken Formation. Prior to development of the Bakken Formation, the existing gas-gathering and processing infrastructure was sufficient to handle the gas production, resulting in 85% to 90% of the gas being sold to market. Since 2007, the two numbers (% gas sold and % gas flared) have been converging. This issue has not gone unnoticed, and infrastructure is being built in an attempt to keep pace with the rapid increase in gas production and to capture the flared gas. Although this rate appears very high on a percentage basis, on a volume basis, North Dakota flared roughly 40% less than Texas or Wyoming[1] (U.S. Energy Information Administration, 2012).

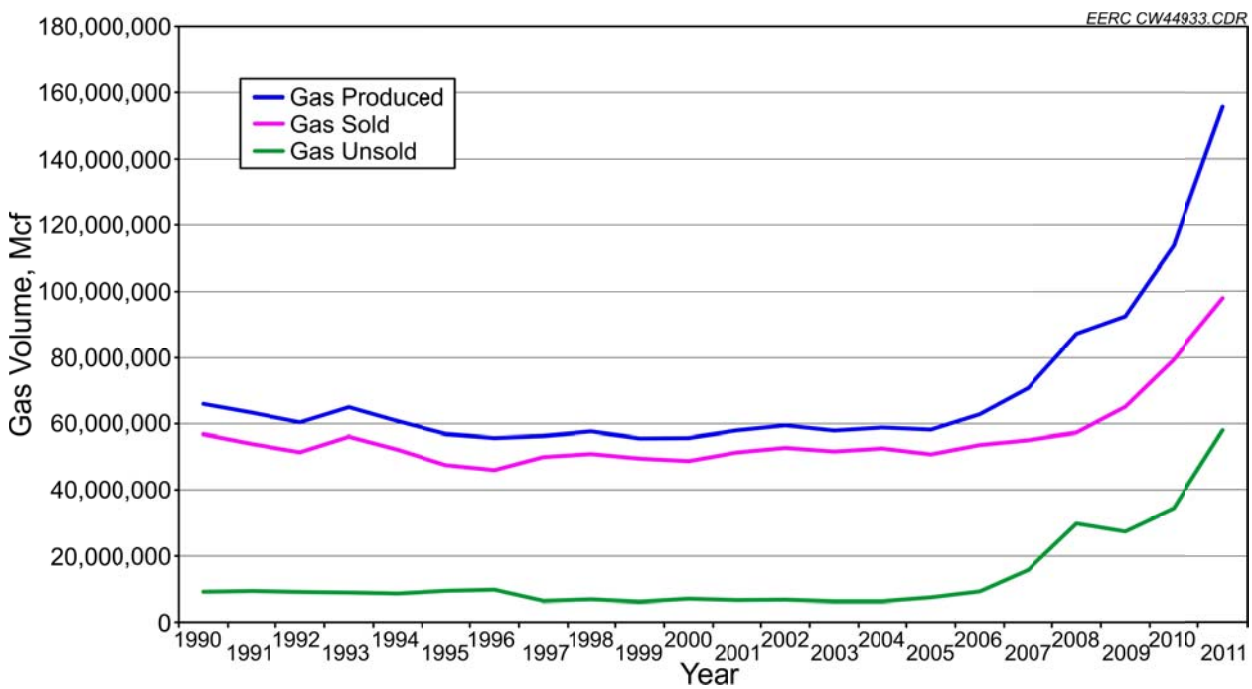


Figure 11. Annual gas produced, sold, and unsold. Data sourced from the North Dakota Industrial Commission, Oil and Gas Division.

[1] Wyoming flaring total includes CO_2-venting volumes.

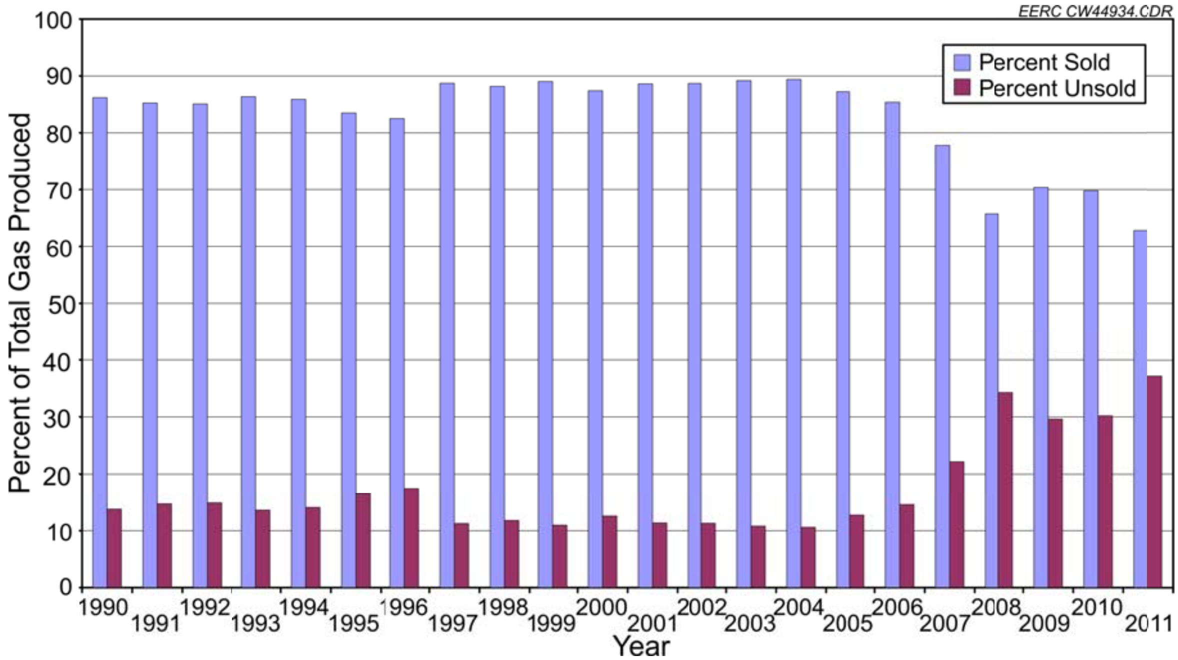


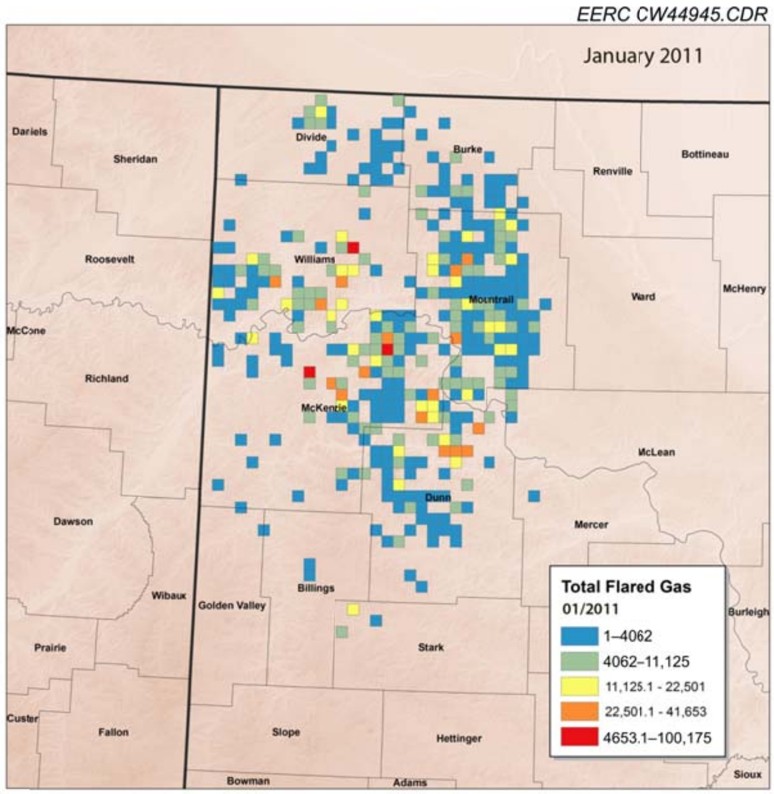
Figure 12. Percentage of gas sold and unsold. Data sourced from the North Dakota Industrial Commission, Oil and Gas Division.

Another important point about the flared gas is that it is a temporally sensitive phenomenon. To better highlight the temporal nature of the flare gas issue, Figure 13 shows the change in flare gas location and quantity during 2011. Using the same grid system described previously, Figure 13 shows the flared gas in January and December 2011, respectively. It should be noted that in any given area, the volume of gas flared changed (in some cases significantly), and this change in volume, and opportunity, poses a significant challenge to matching distributed end-use technology to the source product (flared gas).

Quantity

As presented in previous sections, the quantity of NG from Bakken Formation oil production is substantially greater than oil production from other formations, as shown by the distinct increase in gas production beginning around 2007 (Figure 11). This rapid increase in gas production has outpaced the gas-processing capacity, resulting in an increased volume of gas being flared at the well site (represented as gas unsold in Figure 11).

In 2011, a total of 155,803 MMcf of NG was produced, of which 97,827 MMcf was sold and 57,976 MMcf was unsold. To further define the quantity of NG being flared, Table 2 summarizes the number of wells flaring gas at varying rates per month based on the December 2011 data. Figure 14 shows the same breakdown of wells flaring throughout 2011. Alternatively, the December 2011 data are provided in Table 3 as the number of wells flaring based on Mcf per day. Figure 15 displays the December flaring rates as a percentage of the total flared amount for December. Figure 16 shows the same breakdown for the 2011 calendar year. It should be noted that Table 2, Table 3, Figure 14, and Figure 15 summarize Bakken wells only.



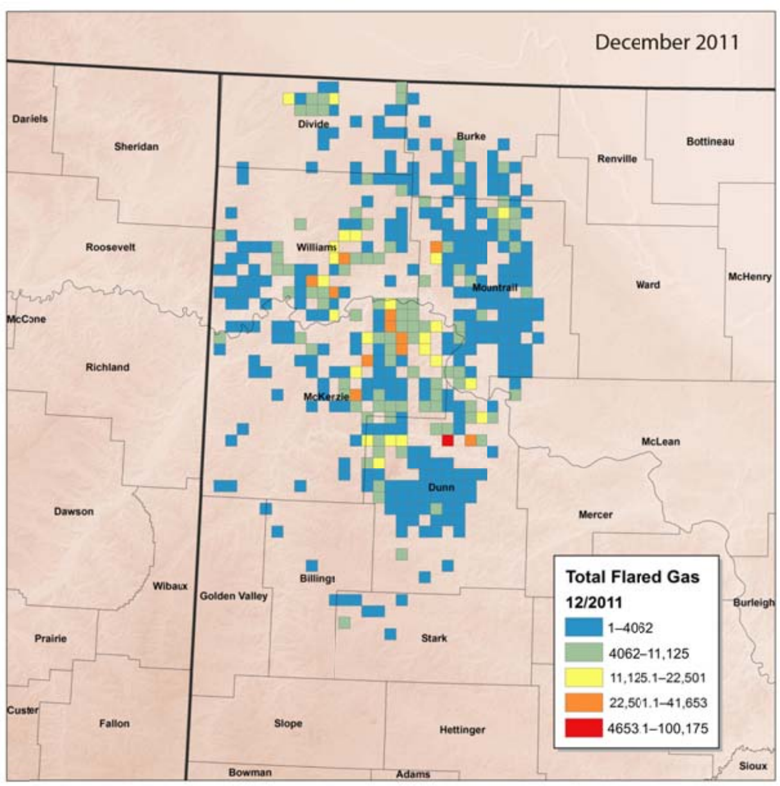


Figure 13. Graphical depiction of flared gas for January and December 2011.

Table 2. Summary of Bakken Wells Flaring Gas Based on Rates/ Month – December 2011 Data

Flaring Rate, Mcf/month	Number of Wells	Percent of Total*
0–499	2228	70
500–999	170	5
1000–4999	522	16
5000–9999	156	5
10,000–19,999	72	2
>20,000	27	1
Total	3175	99

* Does not equal 100% because of rounding.

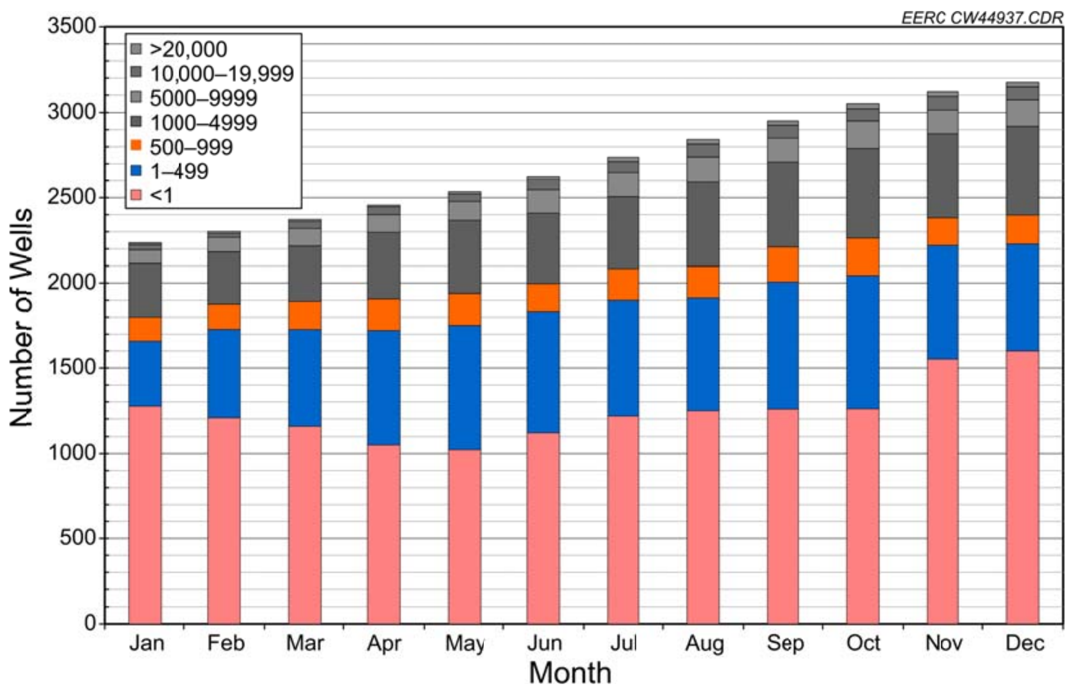


Figure 14. Number of Bakken wells flaring a range of quantities per month for 2011.

NDDMR–OGD has indicated in presentations that it expects, 2000 new wells to be drilled per year for the next several years. Using 2000 new wells per year and an assumed annual gas production of 100,000 Mcf/well (300 Mcf/day) it is anticipated that gas production will increase annually by approximately 200,000,000 Mcf. If gas gathering and processing catch up to production and only 10% is flared, the flared volume would still amount to 20,000,000 Mcf/year from the Williston Basin.

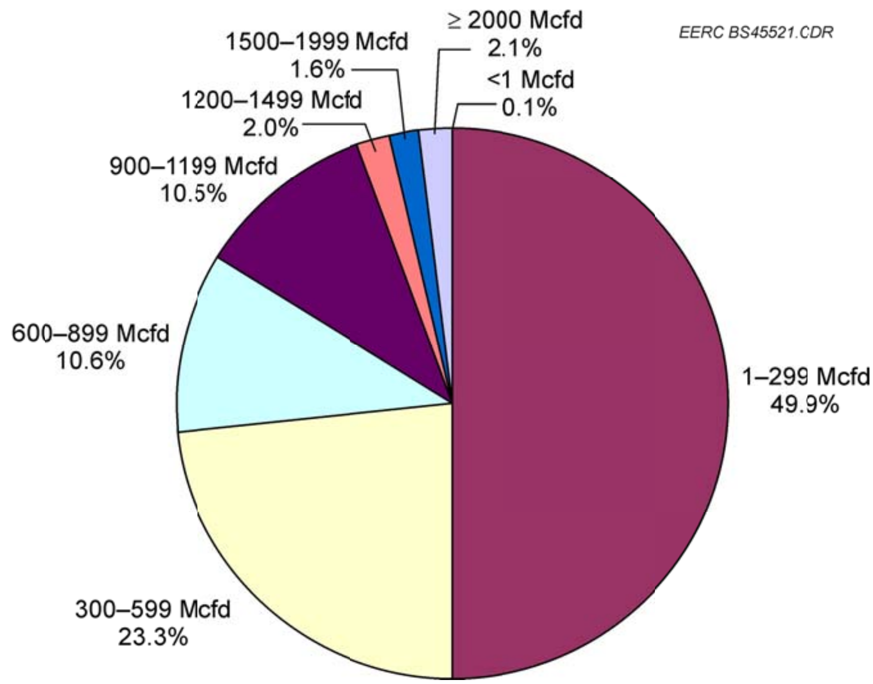


Figure 15. Flaring rates as a percentage of total flared gas for December 2011.

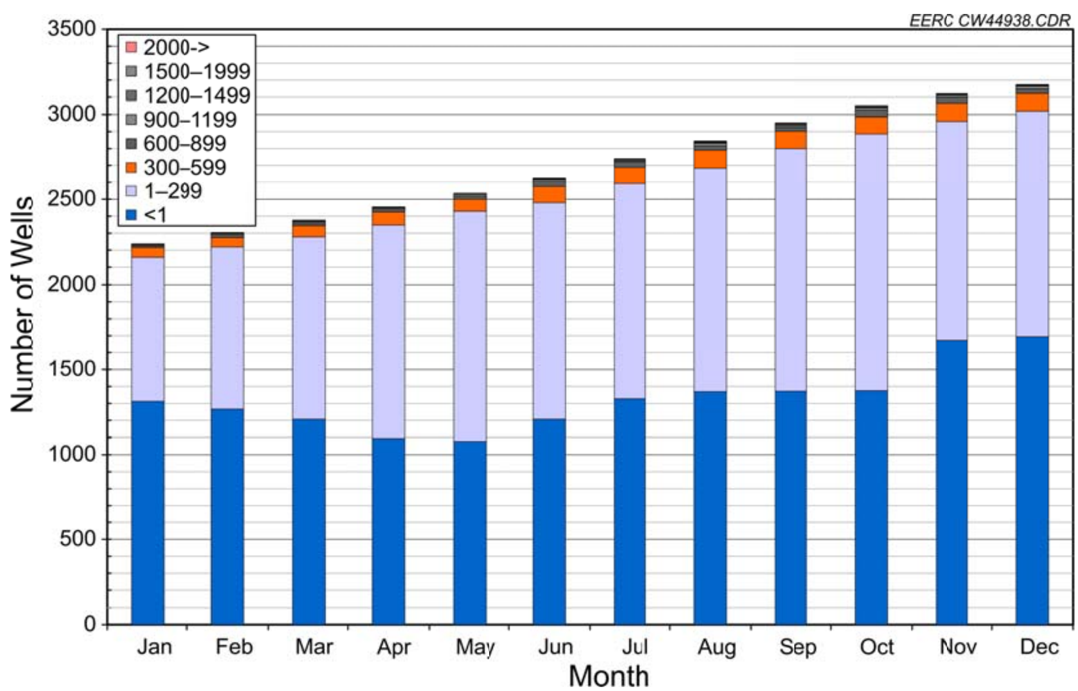


Figure 16. Number of Bakken wells flaring a range of quantities per day for 2011.

Table 3. Summary of Bakken Wells Flaring Gas Based on Rates/Day – December 2011 Data

Flaring Rate, Mcf/day	Number of Wells	Percent of Total, No.-of-wells basis*	Total Gas Flared December, Mcf	Percent of Total, flared-volume basis
<1	1695	53.4	2331	0.1
1–299	1325	41.7	2,178,842	49.9
300–599	103	3.2	1,017,536	23.3
600–899	26	0.8	463,634	10.6
900–1199	17	0.5	457,220	10.5
1200–1499	4	0.1	87,378	2.0
1500–1999	3	0.1	70,974	1.6
>2000	2	0.1	89,621	2.1
Total	3175	99.9	4,367,536	100.1

* Does not equal 100% because of rounding.

This study focused on the opportunity for utilization of associated gas from initial wells drilled on a lease. Associated gas will be available in greater quantities as infill wells are installed, and thus may impact the applicability of certain technologies investigated in this study. It was reasoned that by the time multiple wells are in production, gas-gathering infrastructure will be in place. For this reason and others stated in the report, the authors view the window of opportunity for application of these technologies to be during the initial few months when gas production is at its highest and not as a long-term installation. In most scenarios considered, once gas production has declined sufficiently, the equipment would be mobilized to a new well to capture initial production.

Quality/Physical Characteristics

NG at the wellhead commonly exists as a mixture of methane (C1) with other hydrocarbons, including ethane (C2), propane (C3), butane (C4), pentane (C5), hexane, and higher (C6+). These higher-carbon-number hydrocarbons are often referred to as NGLs. Wellhead NG also contains other compounds such as water vapor, hydrogen sulfide, carbon dioxide, oxygen, and nitrogen. A random sample of Bakken region wellhead gas quality data is presented in Table 4.

Bakken associated gas is typically low in sulfur and high in NGLs. This high NGL content typically corresponds with higher energy content (1300–2000 Btu/ft^3) when compared to residential pipeline gas (~1000 Btu/ ft^3). These NGLs pose unique challenges to utilization, both economically and practically.

Although gas composition can vary within Bakken wells, a gas composition was assumed for the purposes of this study and is presented in Table 5. In addition to the composition in Table 5, the energy content was assumed to be 1400 Btu/ ft^3.

Table 4. Select Associated Gas Quality Data from Wellheads in the Bakken Formation in North Dakota[1]

Wellhead:	A	B	C	D	E	F	G
C1, mol%	70.23	48.07	73.93	50.79	68.05	52.9	66.17
C2, mol%	13.94	18.78	13.25	15.73	14.2	11.32	13.15
C3, mol%	6.7	14.87	5.55	11.61	8.05	8.52	7.01
C4+, mol%	5.5	16.38	4.32	14.42	6.22	6.46	9.37
CO_2 + N_2, mol%	3.44	1.72	2.87	7.29	3.43	19.8	4.18
H_2S	0.19	0.18	0.08	0.16	0.05	1.00	0.12
Wobbe Index, Btu/scf	1470	1712	1454	1563	1491	1207	1519
Methane No. (MN)	53.2	43.5	56.1	44.9	51.6	49.2	48.7

[1] Data from a randomly selected set of wellhead gas analysis provided to the EERC by a number of North Dakota operators.

Table 5. Assumed Bakken Gas Composition

Component	mol%
H_2O (water)	0.02
N_2 (nitrogen)	5.21
CO_2 (carbon dioxide)	0.57
H_2S (hydrogen sulfide)	0.01
C1 (methane)	57.67
C2 (ethane)	19.94
C3 (propane)	11.33
I-C4 (isobutane)	0.97
N-C4 (n-butane)	2.83
I-C5 (isopentane)	0.38
N-C5 (n-pentane)	0.55
C6 (hexane)	0.22
C7	0.09
C8	0.04
C9	0.01
C10–C11	0.00
C12–C15	0.00

Production, Processing, Transport, and Distribution

NG processing acts to separate heavier hydrocarbons (ethane, propane, butane, etc.) and other contaminants (sulfur, nitrogen, oxygen, water, etc.) from the pure natural gas, to produce what is known as “residue gas” or “pipeline-quality” dry NG. Independent transportation pipelines impose varying restrictions on the makeup of the gas that can be injected into the pipeline.

The first processes involved in NG processing typically occur at or near the wellhead. Here, liquid water and oil (condensates) are separated from the "wet" gas. The condensates are trucked to a refinery or gas-processing plant, and the wastewater is normally discarded. In some instances, heaters and scrubbers are installed. The scrubbers remove solid particles. The heaters elevate the gas temperature to avoid formation of icelike methane hydrates.

The minimally processed wellhead NG is then transported to a centralized gas-processing plant through a network of small, low-pressure-gathering pipelines. At the gas-processing plant, three main processes are normally employed to remove the various impurities:

- Water removal
- Separation of NGLs
- Sulfur and carbon dioxide removal

These processes are summarized in the process diagram shown in Figure 17.

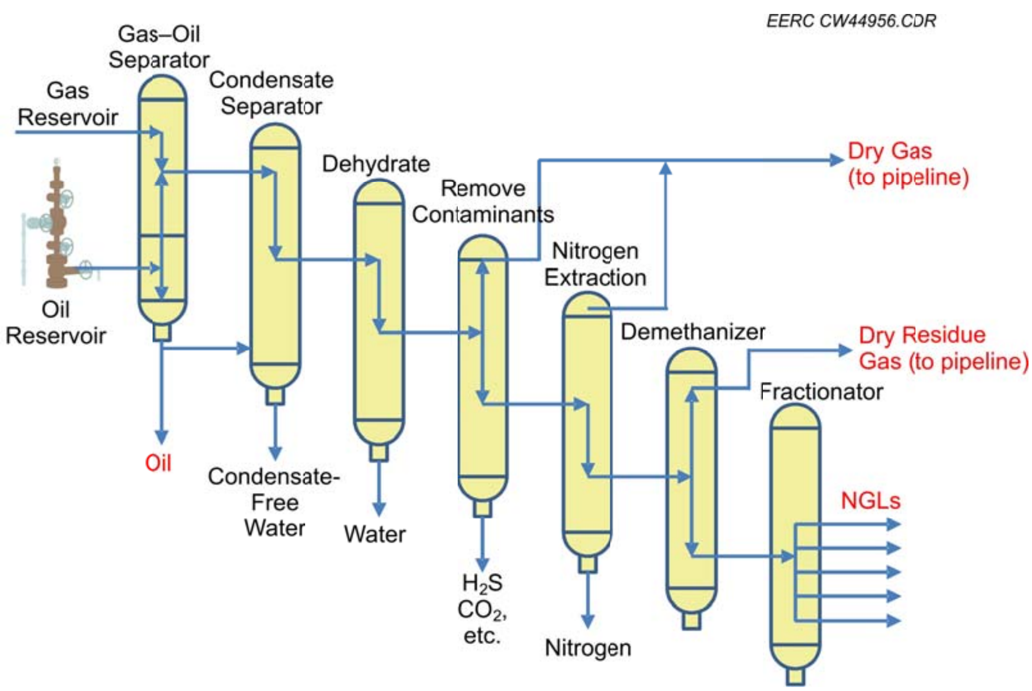


Figure 17. Generalized NG-processing schematic (U.S. Energy Information Administration, 2006).

Water Removal

In addition to separating oil and some condensate from the wet gas stream at the wellhead, water vapor that exists in solution in NG is removed via dehydrating processes – either absorption or adsorption. Absorption occurs when the water vapor is taken out by a dehydrating agent. Adsorption occurs when the water vapor is condensed and collected on the surface. These processes are generally conducted at a centralized gas-processing plant.

Glycol dehydration is a frequently employed absorption process that uses a liquid desiccant to absorb water vapor from the gas stream. Glycol dehydration uses either diethylene glycol (DEG) or triethylene glycol (TEG) in contact with the wet gas stream to absorb water from the wet gas. After absorbing water, the glycol particles sink to the bottom of the contactor, where they are removed. The now-dry NG is then carried out of the dehydrator. The glycol solution is heated in a boiler to vaporize the water out of the solution.

Solid desiccant dehydration is a frequently employed adsorption method that usually consists of two or more adsorption towers filled with solid desiccants, such as silica gel. Wet NG is passed through the towers. Water vapor in the wet NG is sequestered on the surface of the desiccant. Dry NG exits the tower to the NGL separation process.

Separation of NGLs

Removal of NGLs is generally accomplished at centralized gas-processing facilities in two steps. First, the NGLs must be extracted from the NG. Second, these NGLs must be fractionated into their base components.

NGL Extraction

Two techniques account for approximately 90% of all NGL removal from NG streams in gas-processing plants – the absorption method and the cryogenic expander process (Ghosh and Prelas, 2009).

The absorption method of NGL extraction is very similar to using absorption for dehydration. The main difference is that in NGL absorption, absorbing oil is used instead of glycol. This absorbing oil absorbs NGLs in much the same manner as glycol absorbs water. The NG is passed through an absorption tower and is brought into contact with the absorption oil, which absorbs much of the NGLs. The “rich” absorption oil then exits the tower and is fed into lean oil stills, where the mixture is heated to a temperature above the boiling point of the NGLs but below that of the oil. This process recovers approximately 75% of butanes and 85%–90% of pentanes and heavier molecules.

Cryogenic processes are used to extract lighter hydrocarbons such as ethane from NG. These processes use extreme cooling of the gas stream to condense out the lighter NGLs. An effective method of chilling the gas stream is the turbo expander process. In this process, external refrigerants are used to cool the NG stream. Then, an expansion turbine is used to rapidly expand the chilled gases, which causes the temperature to drop significantly (Joule–

Thompson [JT] effect). This process can recover up to 95% of the ethane originally in the gas stream.

NGL Fractionation

NGLs removed from the NG stream must next be broken down into their base components to be marketable. Fractionation is used to accomplish this step. Fractionation uses controlled heating and the boiling points of the different hydrocarbons in the NGL stream to separate gas components. The fractionation process is conducted in discrete steps, starting with the removal of the lighter NGLs from the stream. Fractionators are used in the following order:

- Deethanizer
- Depropanizer
- Debutanizer
- Butane splitter or deisobutanizer – this step separates the iso- and normal butanes

Sulfur and Carbon Dioxide Removal

NG can contain significant amounts of sulfur and carbon dioxide, which must be removed prior to use of the NG as fuel. The process for removing hydrogen sulfide from NG is similar to the processes of glycol dehydration and NGL absorption described earlier. This process is used in approximately 95% of U.S. gas-processing plants. The NG is bubbled through a tower that contains an amine solution having an affinity for sulfur. The effluent gas is typically free of sulfur compounds. Like the process for NGL extraction and glycol dehydration, the amine solution is typically regenerated. Although most NG desulfurization involves the amine absorption process, it is also possible to use solid desiccants such as iron sponges to remove the sulfide and carbon dioxide.

Straddle Extraction Plants

In addition to processing done at the wellhead and at centralized processing plants, final polishing is sometimes accomplished at straddle extraction plants. These plants are located on major pipeline systems. Although the NG that arrives at these straddle extraction plants is already of pipeline quality, there may exist small quantities of NGLs that are extracted at the straddle plants.

Interstate Pipeline Transport

Interstate NG pipelines have gas quality requirements that vary from pipeline to pipeline but are established for each pipeline under its Federal Energy Regulatory Commission (FERC) gas tariff. Tariff terms and conditions typically limit such gas characteristics as the following:

- Presence on nongaseous constituents (such as particulates, gums, and oil)
- Heating value
- Liquid hydrocarbon content (expressed as dew point)
- Hydrogen sulfide, total sulfur, and mercaptan sulfur

- Hydrocarbon components
- Water
- Undesirable constituents like carbon dioxide, oxygen, nitrogen, and mercury
- Specific gravity
- Hydrogen
- Helium
- Deleterious (toxic or hazardous) substances
- Microbial agents
- Temperature

Summary of Bakken Associated Gas

Based on the information presented in the previous sections, several key points have been provided to summarize the current state of oil and gas development as well as the opportunities as hypothesized by the authors:

- North Dakota is experiencing unprecedented oil and gas production from the Williston Basin in the western part of the state. Assuming continued strong prices for oil and continued completion technology evolution, the development of the Williston Basin is expected to continue at a rapid pace.

- The primary formation targeted for production is the Bakken Formation, a tight shale formation requiring horizontal drilling and hydraulic fracturing stimulation to produce economical quantities of oil.

- The Bakken Formation is an oil play but contains significant quantities of associated NG, which is high in NGLs.

- Currently, the value of the NGLs is substantially higher than the value of the "residue" gas, and separation of the NGLs, if economical, makes sense and can enable the economic viability of other NG uses.

- The combination of prolific oil production from Bakken wells, the currently high crude oil price, and the significant quantity of associated gas has resulted in a volume of NG production that exceeds the current gas-gathering and processing infrastructure. The excess of gas has forced producers to flare large quantities of NG at some "stranded" well sites.

- Given that industry, regulators, and the general public wish to minimize this flaring, the amount of flared NG is likely to decrease significantly in the future.

- The best opportunity for capturing and utilizing the flared gas in a nontraditional manner (i.e., a use other than delivery and processing at a NG plant) is likely to be time-sensitive. That is, infrastructure will eventually be built out and gas will be captured. The opportunity to capture the gas exists after the well is put into production and before gas gathering occurs. Modularity and mobility will also be vital in any feasible distributed opportunity.

ALTERNATIVE APPROACH FOR SMALL-SCALE GAS PROCESSING AND NGL RECOVERY

Background

The overarching purpose of this study was to identify alternative uses of stranded rich associated gas that could provide an economical alternative to flaring while efforts continue to build gas-gathering and processing infrastructure needed to accommodate the rapid expansion of oil and gas production in the Bakken Formation. Emphasis was placed on uses that derived economic and environmental benefit while allowing a minimum amount of gas cleanup. Within the study, the authors recognized that to be competitive, small-scale gas utilization approaches would need to be mobile, moving to where stranded gas is available or competitive with centralized gas processing, thereby allowing the technology to remain in place even after gas-gathering pipelines are installed.

Two obvious gas uses were identified that have large NG demand and match the geographically distributed gas resource: transportation fuel and power. The high price of transportation fuel relative to NG creates some advantages; however, rich gas cannot be used in standard NG vehicles (NGVs) because of concerns over emissions and engine performance. In the case of power production, NGLs contained in the rich gas are more valuable in the chemical market than as a combustion fuel or associated electricity. Further, they do not necessarily improve engine performance. As such, small-scale NGL recovery, although less efficient than at large centralized facilities, may be an enabling technology, allowing value to be extracted from the associated gas while improving economical utilization of leaner gas for transportation and power. Further, at some locations, where geography and economics prevent gas gathering, even low-efficiency NGL recovery approaches may provide an attractive alternative with no flaring.

Summary of Alternative Gas-Processing Technologies

The goal of this study is not to define a specific distributed-scale gas-processing system but, rather, to identify opportunities to work outside the typical centralized gas plant model and identify conditions that could allow technical and economic feasibility. The approach taken by this study is to examine the broad unit functions employed in traditional gas processing, then identify new alternatives that may offer potential paths for further research focused on applicability to smaller-scale implementation. The unit functions can be broken down as follows:

- Acid gas removal
- Dehydration
- Nitrogen rejection
- NGL recovery

Acid Gas Removal

In most cases, because of low content, acid gas removal is not required on Bakken associated gas. In general, potential acid gases to be removed from NG streams are CO_2 and H_2S. CO_2 is essentially a neutral compound and, in most cases, is removed via the formation of carbonic acid. This is a kinetically slow process that may require catalysis. H_2S is much more reactive and is easier to remove. Several conventional and alternative technologies can be applied to acid gas removal. A summary of these technologies is presented in Table 6.

Table 6. Possible Distributed-Scale Acid Gas (SO_2 and CO_2) Removal Technologies

Absorbents (solvents)
Physical
Chemical (organic, inorganic)
Physical/Chemical
Adsorbents (pressure swing adsorption, online or off-line regeneration)
Molecular Sieves
MOFs
PURASPEC (ZnO for H_2S removal)
Membranes
Polymer
Zeolites

Several alternate acid gas removal technologies are currently under development. Some of these technologies are being investigated already within the EERC's gasification and syngas purification programs. Some of these technologies hold near-term promise for small-scale NG-processing applications.

New semipermeable membrane technologies enable separation of acid gases and water from the NG stream. However, with current technology, it is difficult to adjust the relative rates of diffusion of CO_2 and H_2S. Therefore, a distributed gas-processing system utilizing this technology must be designed to meet the CO_2 specification. A fixed-bed adsorbent may then be used to remove H_2S subsequently to meet the sulfur specification.

Metal organic frameworks (MOFs) have been investigated by many (including DOE NETL, UOP, Sandia National Laboratories, U.S. Army Edgewood Chemical Biological Center [ECBC] and others) as highly efficient, easily regenerable acid gas absorbers (Willis, 2010; Peterson and Rossin, 2008). MOFs are novel crystalline compounds consisting of metal ions structured within organic molecules to form multidimensional porous structures. Chemisorption occurs because the framework has a strong affinity for the acid gases possessing high adsorption enthalpies. The framework chemistry is also conducive to easy release of the guest molecules (acid gas) when regeneration is desired. It may be possible to advance MOF state of the art to suit a distributed gas-processing application.

Dehydration

Compounds known as gas hydrates can form when liquid water is present in NG lines and temperature and pressure conditions are favorable. These hydrates can agglomerate and plug NG transport pipes and valves. Therefore, pipeline operators typically require that water vapor in the gas be removed to levels lower than the saturation point at the lowest expected pipeline temperature plus a margin of safety. The dehydration step is typically completed both at the wellhead and after separation of hydrocarbon liquids and removal of acid gases at a gas-processing plant. Several dehydration process alternatives are summarized in Table 7. Selection among these alternatives can be guided by the chart shown in Figure 18.

Table 7. Possible Distributed-Scale Water Removal Technologies

Direct Cooling
Absorption
Glycol
Alcohols
Membranes
Adsorbents (pressure swing adsorption, on-line or off-line regeneration)
Activated Alumina, Silica Gel
Alkali Metal Chlorides (KCl, LiCl), Alkaline-Earth Metal Chlorides ($CaCl_2$)
Molecular Sieves (zeolites)

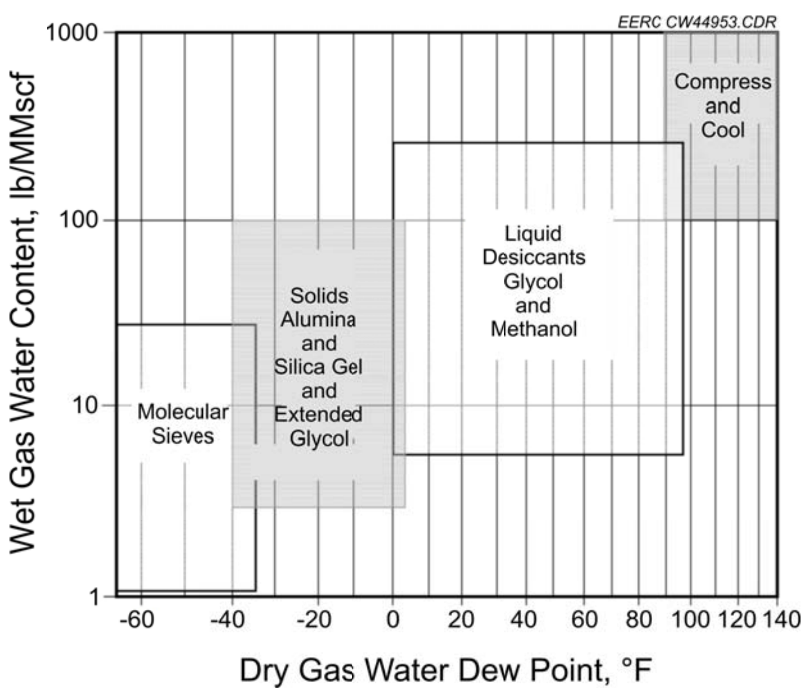


Figure 18. Dehydration technology selection guide (Huffmaster, 2004).

Liquid Desiccants

Dehydration with liquid desiccants typically involves the use of a glycol solution in an absorber column. It can also be combined with cooling. It is the most widely applied process, used extensively in production operations and in many refinery and chemical plant operations. DEG or TEG are typically used in field gas or gas-processing plant residue gas streams. For chilled contacting, ethylene glycol is used.

Methanol has also been employed in dehydration processes. Methanol is used either in direct injection or contactor absorber processes. Because methanol has a high vapor pressure, losses to the vapor and liquid hydrocarbon phases are considerably higher than with glycols. Methanol recovery methods such as IFPEXOL must be employed.

Cooling Below Initial Dew Point

Low-temperature separation (LTS) can be employed to dehydrate a gas stream. This method generally requires additional steps to prevent hydrate formation. For example, ethylene glycol can be used in conjunction with LTS for hydrate prevention and simultaneous dehydration of the gas. New rapid expansion technologies such as Twister® have also been combined with LTS to achieve dehydration.

Solid Desiccants

Dehydration of NG with solid desiccants is usually limited to those cases where complete water removal is desired, for example, in cryogenic plants operating in the region of −100° to −150°F or where a relatively small volume of gas is being processed.

Molecular sieves are also being employed in the gas-processing industry for cryogenic plant feed-conditioning applications and some sour gas applications with special acid-resistant binder formulations. Dehydration of NG to a typical pipeline requirement of 7 lb_{water}/MMscf is normally least costly utilizing a liquid desiccant such as glycol, rather than using solid desiccants.

Solid desiccants such as activated alumina and silica gel have been successfully used for many years in production and processing applications that require lower dew point than achieved by conventional glycol. With silica gel, it is possible to simultaneously remove hydrocarbons and water. However, with solid desiccants, regeneration becomes a significant design factor. Multiple-bed systems are used on gases with relatively low water content. Typically, one or more beds are in service drying gas and one or more beds are in regeneration mode.

Deliquescent Desiccants

Deliquescent systems can be economical for smaller gas volumes typical of wellhead rates up to 1 MMcf. Deliquescent desiccants generally comprise naturally hygroscopic alkaline-earth metal halide salts, e.g., calcium chloride. Water vapor is removed from NG as it flows through a bed of desiccant in a pressure vessel. Moisture is attracted to the deliquescent desiccant and coats it with hygroscopic brine. This brine continues to attract water, forms a droplet, and then migrates with gravity to a liquid sump. Since the desiccants dissolve upon attracting and absorbing water vapor, relatively inexpensive new desiccant is simply added to the vessel when needed.

Nitrogen Rejection

Nitrogen rejection unit operations will not always be required. The necessity of this operation will depend heavily upon the characteristics of the gas field to which the distributed operation is being applied. When nitrogen rejection is required, one of two technologies is typically employed – cryogenic technology or selective gas-permeable membrane technology. Cryogenics are generally assumed to be power-intensive and, therefore, not adaptable for use at a distributed scale. Selectively permeable membrane technology may be scalable to this size.

NGL Recovery

Because of the relatively high value of products produced, NGL recovery technology options exist for larger and smaller gas-processing applications. The general approaches employed by these technology options are summarized in Table 8. In general, these approaches fall into one of three categories of processes:

- Control of temperature and pressure to achieve condensation of NGLs
- Separation of heavier NGLs from lighter gas with pressurized membrane separation systems
- Physical/chemical adsorption/absorption

Table 8. Possible Distributed-Scale NGL Recovery Technologies

Turboexpander + Demethanizer
JT Low-Temperature Separation
Membranes
Absorption
Refrigerated Lean Oil Separation (RLOS)
Adsorption
Activated carbon
Molecular Sieve
Twister Supersonic Gas Low-Temperature Separation Dew-Pointing Process

Turboexpansion

A commonly employed approach to NGL recovery at industrial gas-processing plants is to use a turboexpander in conjunction with a demethanizer. One manufacturer's hardware is shown in Figure 19. In this approach, a heat exchanger first chills the inlet gas where a gas–liquid mixture results from condensation of NGLs. The gas–liquid mixture is separated in a simple knockout pot. The liquid stream from the knockout pot flows through a throttling valve. This results in lowering the temperature of the stream significantly before the stream enters the demethanizer (distilling column). In parallel, the gas stream from the knockout pot enters the turboexpander where it undergoes a rapid expansion that again lowers the gas stream temperature before it enters the demethanizer to serve as distillation reflux.

Figure 19. CryoStar turboexpander and demethanizer.

Liquid from various levels of the demethanizer is drained through the heat exchanger, where it repeatedly absorbs heat from the inlet gas being cooled. Warmed liquid is returned to the lower section of the demethanizer. In effect, the inlet gas provides the low-grade heat required to vaporize the liquid from the bottom of the demethanizer. The turboexpander removes the heat required to provide distillation reflux to the top of the demethanizer.

The demethanizer produces gas that is suitable for distribution to end-use consumers by pipeline. A gas compressor driven by the turboexpander compresses the product gas before injection into the distribution pipeline. The NGL product from the demethanizer is also warmed in the heat exchanger as it cools the inlet gas. The NGLs are then sent to storage for distribution to market.

JT Separation

Several companies offer skid-mounted systems that employ the JT effect to chill gas and condense NGLs. An example of such a system is shown in Figure 20. A JT unit typically consists of a gas-to-gas exchanger, a JT (throttling) valve, and a gas–liquid separator. In this respect, it is similar to the turboexpansion process, except that it employs no rotating machinery to accomplish the expansion, and does not rely on a demethanizer.

EERC CW44954.CDR

Figure 20. Small JT NGL recovery skid as provided by dew point control.

The process of expanding gas to produce cooling can be cost-effective when excess supply pressure is available. However, JT units become expensive to operate when the pressure reduction across the JT valve must be provided by front-end gas compression. A JT unit might require up to 1000 psi differential pressure to operate efficiently.

Twister Supersonic Separation

The Twister supersonic separator (shown in Figure 21) has thermodynamics similar to a turboexpander, combining the following process steps in a compact, tubular device:

- Expansion
- Cyclonic gas–liquid separation
- Recompression

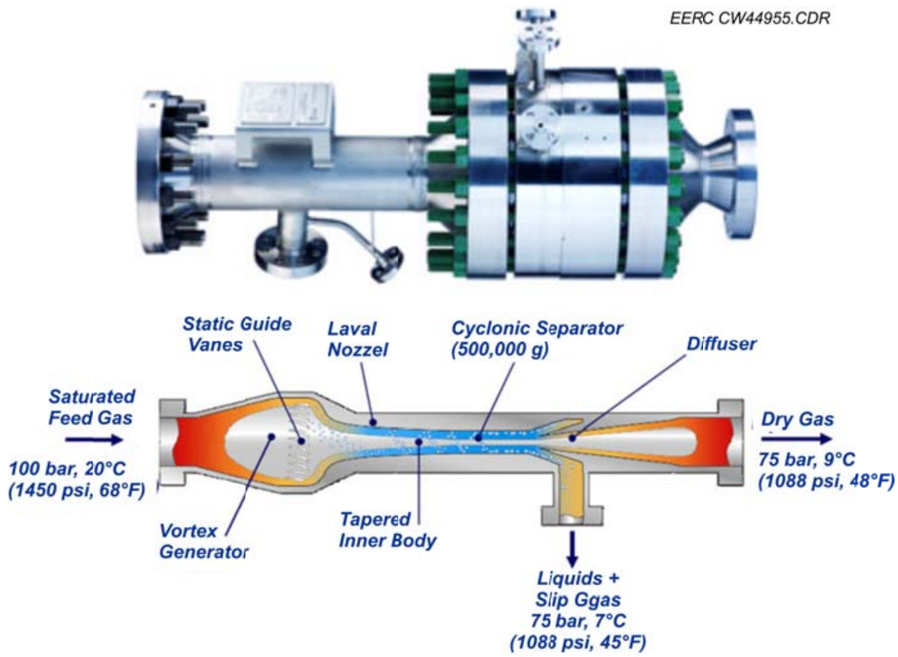


Figure 21. Twister supersonic separator.

Whereas a turboexpander transforms pressure to shaft power, Twister achieves a similar temperature drop by transforming pressure to kinetic energy. Twister technology employs the following gas–liquid separation steps:

- Multiple inlet guide vanes generate a high-vorticity, concentric swirl.
- A nozzle is used to expand the saturated feed gas to supersonic velocity, which results in a low temperature and pressure.
- The rapid expansion results in the formation of a mist of hydrocarbon condensate.
- The high-vorticity swirl drives the droplets to the wall with centrifugal force.
- The liquids are separated from the gas using a cyclonic separator.
- The separated streams are slowed down and repressurized in separate diffusers.
- The liquid stream contains slip gas, which is removed in a compact liquid degassing vessel and recombined with the dry gas stream.

Small-Scale NGL Recovery for Stranded Gas

Small-scale NGL recovery has the potential to provide several benefits to the industry. Gas that cannot yet be gathered and marketed is typically flared, resulting in unutilized energy, the loss of revenue, and emissions from the flared gas. Deploying small-scale NGL recovery systems as an interim practice while gathering lines are built allows the greatest value and most easily transported hydrocarbons to be captured and marketed. Further, the leaner gas generated from these systems can be more easily utilized for power and transportation fuel or transported as a compressed gas. As an alternative, the lean gas can still be flared, as shown conceptually in Figure 22, generating a lower emission profile than rich gas.

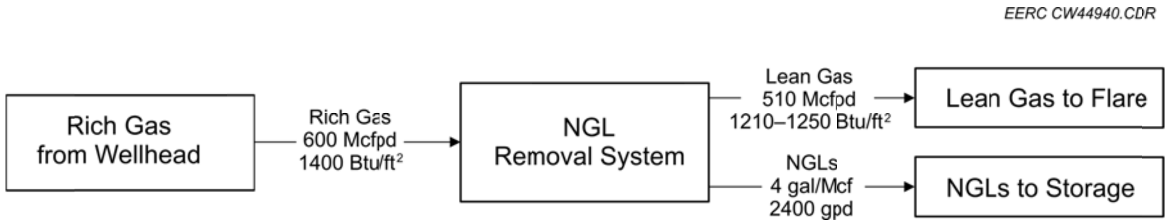


Figure 22. Block flow diagram of NGL removal system.

Industry experience indicates that 10 to 12 gallons of NGLs/Mcf of associated gas is present in many producing Bakken wells. At an estimated NGL removal rate of 4 gallons/Mcf (from 1000 Mcf/day of rich gas), the daily production of NGLs would be approximately 4000 gallons of NGLs per day. Since the NGLs make up a majority of the economic value of the rich gas, removal of at least a portion of the NGLs from the rich gas has both economic potential and an environmental benefit to the flare emissions. To evaluate the potential viability of small-scale NGL recovery, a simplified model was developed based on a JT-based technology. The NGL removal system evaluation assumes the parameters shown in Table 9.

Table 9. Assumptions for Evaluation of a NGL Removal System

Parameter	Assumed Value
Rich Gas Flow Rate from the Wellhead, average	300 Mcf/day
Rich Gas Flow Rate Processed, economic cutoff	600 Mcf/day
Rich Gas Flow Rate, design flow	1000 Mcf/day
Rich Gas Heat Content	1400 Btu/ft^3
Rich Gas Price (cost) at the Wellhead	\$0.00/Mcf
Volume of NGLs Existing in Rich Gas	10–12 gallons/Mcf
NGL Price, value	\$1.00/gallon
Lean Gas Flow Rate from NGL Removal System	85% of rich gas flow rate
Lean Gas Heat Content	1210–1250 Btu/ft^3
Lean Gas Price, value	\$2.00/Mcf

Capital costs for the NGL removal system comprise two main components: compression and chilling and storage. The compression-and-chilling system is based on a design requirement of −20°F and 1000 psi (from an assumed pressure of 35 psi at the heater/treater). The storage of NGLs was based on a desire to have 2 weeks of storage capacity, or approximately 56,000 gallons (1300 bbl), or four 400-bbl tanks. The estimated capital cost for the NGL removal system of $2,500,000 is based on vendor quotes and industry discussion. Operating and maintenance (O&M) costs were assumed to be 10% of the total capital cost, or $250,000 (Table10). Revenue calculations are based on NGL sales only at $1.00/gallon and a recovery rate of 4 gal/mcf. In this scenario, it has been assumed that residue gas is flared.

Table 10. Summary of NGL Removal System Costs and Revenue

Description	Capital Cost	Annual O&M Cost	Annual Revenue[1]
NGL Removal System, 300 Mcfd rich gas	$2,500,000	$250,000	$350,400
NGL Removal System, 600 Mcfd rich gas	$2,500,000	$250,000	$700,800
NGL Removal System, 1000 Mcfd rich gas	$2,500,000	$250,000	$1,168,000

[1] Assumes 80% annual system availability and no cost for rich gas.

Although the technical aspects of NGL removal are fairly straightforward, the business and contractual aspects do not share that simplicity. Several business models could be employed which are summarized in the following sections.

Fee for Service

The simplest business model for all parties involved is to provide the service of separating NGLs from the rich gas for a fee (most likely on a dollar-per-gallon basis). In this scenario, the operator pays a third party to separate the liquids, and the operator sells the liquids and either continues to flare the lean gas, sells it, or sends it on to gas processing via gas-gathering infrastructure.

Monetization of Products by Third Party

More complicated but still plausible would be a scenario where the entity separating the NGLs from the rich gas buys the rich gas, removes the NGLs, and sells the NGLs (and likely the lean gas as well). If the entity separating the NGLs is a third party and not the current operator, the contractual and financial aspects are likely quite complicated.

Monetization of Products by Operator

If the current operator chooses to perform the well site NGL separation, contractual and financial issues would likely be managed similar to existing contracts with royalty owners consistent with existing contractual relationships.

Conclusions

Although the economic viability of NGL removal systems is highly dependent on how the business entity is positioned in the supply chain and contractual considerations, sufficient value is contained within the recovered NGL to suggest an economical business plan could be developed.

Clearly, NGL recovery would be most economical at wells flaring larger quantities of gas immediately after production begins in order to capture the greatest volume of gas. Additionally, such a technology would benefit from being mobile and easily mobilized and commissioned every several months. The value achievable from trucked delivery of NGL is also a critical factor in determining economic viability. Businesses with their own gas-processing facilities would likely gain the greatest value. Those relying on third-party truck unloading may experience smaller profit margins.

APPLICATION I – CNG/LNG FOR VEHICLES

Introduction

A possible utilization of flared gas is to purify and compress it for use in NGVs. The gas vented or captured at the wellhead is too rich and variable in composition to be used effectively in NGV engines; therefore, extensive small-scale gas processing would be required to implement this utilization strategy upstream of typical large-scale gas plants. CNG for vehicles is a commercial off-the-shelf product with original equipment manufacturer (OEM) and aftermarket engine options as well as fueling stations available from vendors. Provided NG is available with sufficient quality and quantity, CNG can provide a cost-effective and low-emission alternative to gasoline and diesel, and the economics are well understood. The purpose of this study was to evaluate adaptation of CNG upstream of the gas plant to positively impact flaring. For these applications to be feasible, a significant amount of small-scale gas processing will be necessary, including purification, compression, and dispensing of CNG fuel. Further, the vehicle fleets utilizing the CNG fuel would need to be adaptable and flexible in order to take advantage of stranded gas resource that changes in quality, quantity, and location with time.

It is generally assumed that a new wellhead in North Dakota can flare gas for up to a year before North Dakota oil and gas regulators demand that the associated gas be captured for use at the well site or gathered and transported to centralized gas-processing plants. The CNG fueling system and accompanying fleet would need to be capable of following this transient resource or models would need to be adapted to enable fueling infrastructure to remain in place as gas-gathering pipelines fill in around the CNG infrastructure.

CNG and LNG Fundamentals

NG has been used as an engine fuel since 1860, long before gasoline engines were commercialized. The first U.S. vehicles to use NG as a fuel were put on the road in the 1960s. In 2009, the U.S. CNG vehicle fleet numbered 114,270. At the same time, the LNG vehicle fleet numbered 3176. Worldwide, approximately 13.2 million NGVs are in use. In the past two decades, the number of NGVs on U.S. roads has increased nearly 500%. Transit buses account for approximately 62% of all CNG motor fuel use (U.S. Energy Information Administration, 2012a).

The United States does not lead the world in use of NGVs. As shown in Figure 23, many countries surpass the United States in NGV utilization. The reasons frequently cited include:

- Lack of demand: Many major manufacturers sell CNG cars elsewhere in the world. Lack of demand has, to some extent, prohibited their entrance into the U.S. market.

- Limited range: CNG tanks designed to operate at 3500 psig require more on-vehicle volume per unit energy than their gasoline or diesel cousins. The Honda GX has a range of about 200–250 miles, half that of the gasoline model.

- Safety: Some U.S. consumers express concerns about the safety of CNG, despite the CNG industry’s justifiable claims that it is safer than gasoline.

- Lack of filling stations: There are more than 1000 CNG filling stations in the United States, but less than half of them are open to the public. An Italian company called FuelMaker sells a home fueling system, called Phill, which compresses and fills NGV tanks at home. However, the home device takes several hours to fill the tank and costs several thousand dollars to purchase and install, if local building codes permit its installation and use.

- Additional cost of engine: One of the largest barriers to wider use of NGVs is the incremental cost of purchasing an OEM NGV or converting existing vehicles. One of the largest components of the cost of CNG conversion is compliance with strict U.S. Environmental Protection Agency (EPA) and California Air Resources Board (CARB) regulations. Conversion kit makers must go through a complex certification process, and kits must be installed by certified technicians.

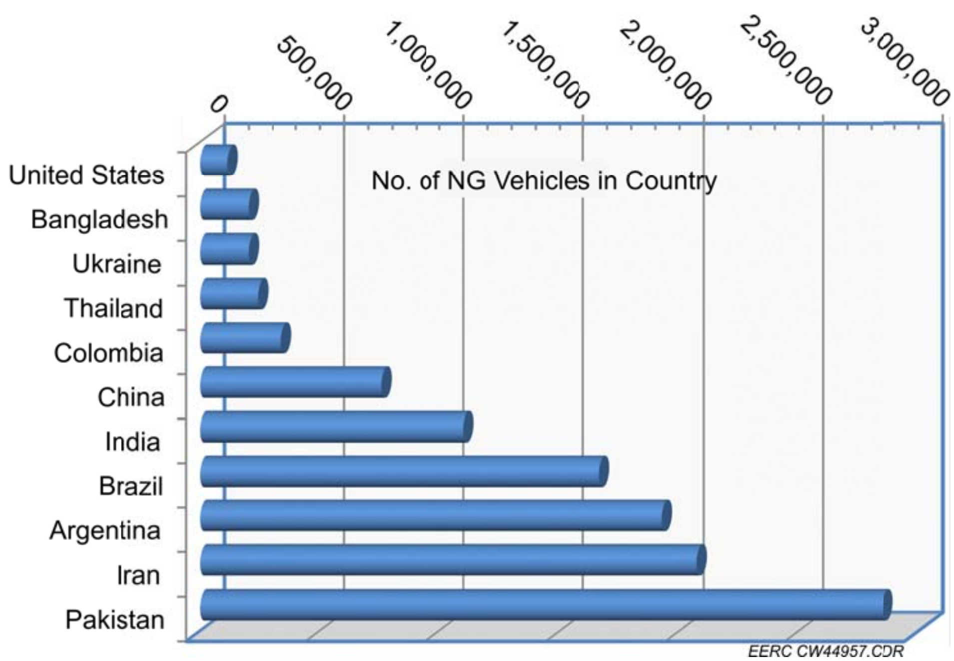


Figure 23. NGV use by country (NVG Journal, 2012).

Having established some of the barriers to NGV use in the United States, strong factors are also playing into a reinvigorated impetus to consider NGVs. Strongest among these market forces is the price gap between CNG and gasoline. This gap is currently at record levels because of supply and demand factors stemming from a wealth of new NG source discoveries in the United States. As a result of this increased supply, CNG prices are ranging from \$1.00–\$3.00 lower than gasoline, on a GGE basis. Continued low CNG prices could further encourage more widespread use of CNG for fleet vehicles.

CNG must be stored in tanks at pressures up to 3600 psi to offer the vehicle adequate driving range. Alternatively, LNG, which is 2–3 times more dense than CNG (3500 psi), can also be stored in vacuum-insulated pressure vessels. LNG is typically used only with heavy-duty vehicles, where a greater fuel quantity demand exists.

LNG contains a significantly higher ratio of methane to heavier hydrocarbons. This is because of the processing required to liquefy the NG. As the NG is compressed and significantly cooled to −260°F, heavier hydrocarbons (NGLs) condense and are separated from the methane. This precipitation and separation occurs to a much lesser degree with CNG because CNG is not significantly cooled, except to compensate for the rise in temperature due to compression. Because LNG fuel is much closer to pure methane than most CNG fuels, LNG does not present the same challenges in emissions or fuel quality variation that CNG does.

CNG-powered vehicles attain roughly similar fuel economy when compared to conventional gasoline vehicles, on a GGE or energy content basis. A GGE is a quantity of CNG or LNG that contains the same amount of energy (measured in Btus or joules) as a gallon of gasoline. One GGE is roughly 5.7 lb of CNG or roughly 1.5 gallons of LNG.

CNG Feedstock Availability and Quality

Gas processing of Bakken associated gas is generally accomplished at centralized gas-processing plants in North Dakota. The residue gas produced at these gas-processing plants is injected into pipelines that traverse North Dakota. Table 11 presents select samples of pipeline gas quality data from various locations in these pipelines.

The gas quality varies quite dramatically between pipeline operators and geographic locations. What cannot be seen in this summary is the gas quality variation over time. A summary of the variability in gas quality at these same pipeline stations over the 3-month period of October–December 2011 is presented in Table 12.

Liss and Thrasher (1992) produced the most frequently referenced survey of variation (both temporal and geographic) in natural gas composition in the United States. This survey documented wide variations in NG quality across the United States. A brief summary of this extensive data set is captured in Table 13. This study also concluded that gas quality variations over time across the nation are highly variable.

Table 11. Select Gas Quality Data from North Dakota Pipeline Stations, 4th Quarter 2011[3]

	WBIP[1] Williston–Ray	WBIP N. Tioga Transfer–Ray	WBIP Baker–Little Beaver	WBIP Dickinson–Glen Ullin	WBIP Bismarck–Glen Ullin	NBIP[2] Guardian	NBPC Glen Ullin
C1, mol%	69.25	71.29	91.92	82.98	82.98	95.44	95.49
C2, mol%	23.06	21.15	3.10	12.07	12.13	2.14	1.95
C3, mol%	3.13	3.29	0.46	1.00	1.00	0.21	0.14
C4+, mol%	0.30	0.29	0.09	0.07	0.08	0.03	0.01
$CO_2 + N_2$, mol%	4.27	3.98	4.43	3.88	3.81	1.97	2.21
H_2S, mol%	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wobbe Index, Btu/scf	1414	1411	1298	1353	1355	1331	1324
MN	62.0	63.2	96.9	78.4	78.3	101.2	102.2

[1] Williston Basin Interstate Pipeline.
[2] Northern Border Interstate Pipeline.
[3] Sources: transmission.wbienergy.com and www.northernborder.com.

Table 12. 3-month Variability in Gas Quality Data at North Dakota Pipeline Stations, 4th Quarter 2011[1]

	WBIP Williston–Ray	WBIP N. Tioga Transfer–Ray	WBIP Baker–Little Beaver	WBIP Dickinson–Glen Ullin	WBIP Bismarck–Glen Ullin	NBPC Glen Ullin	NBPC Guardian
Calculated Dry Gross Btu/ft³	1193–1237	1186–1620	971–1144	1011–1179	1006–1176	1003–1019	1006–1019
C1, mol%	67.85–72.51	34.08–73.85	51.14–95.41	73.74–95.98	71.46–91.21	94.12–95.79	95.04–96.11
C2, mol%	19.44–23.31	10.05–22.24	0.30–23.67	1.93–23.03	4.20–21.58	1.62–2.97	1.58–2.48
C3, mol%	3.01–4.96	3.11–33.28	0.03–6.98	0.14–1.56	0.21–2.70	0.11–0.33	0.10–0.29
i-C4, mol%	0.08–0.26	0.04–0.25	0–0.21	0–0.05	0.01–0.09	0–0.03	0–0.03
n-C4, mol%	0.15–0.63	0.07–0.55	0–0.55	0–0.11	0.01–0.20	0–0.03	0–0.03
i-C5, mol%	0.01–0.05	0–0.05	0–0.01	0	0–0.02	0–0.01	0–0.01
n-C5, mol%	0.01–0.06	0–0.05	0–0.03	0	0–0.02	0	0
C6+, mol%	0–0.02	0–0.02	0–0.01	0	0–0.03	0	0–0.01
$CO_2 + N_2$, mol%	3.4–5.3	2.53–4.67	3.92–17.40	1.93–4.28	3.0–4.86	2.04–2.40	1.76–2.16

[1] Sources: transmission.wbienergy.com and www.northernborder.com.

Table 13. Select National Statistics for NG in 26 Major Urban Areas of the United States (Liss and Thrasher, 1992)

	National Mean	National Minimum with PA[1]	National Minimum Without PA	10th Percentile Nationwide	90th Percentile Nationwide
C1, mol%	93.9	55.8–98.1	74.5–98.1	89.6	96.5
C2, mol%	3.2	0.5–13.3	0.5–13.3	1.5	4.8
C3, mol%	0.7	0.0–23.7	0.0–2.6	0.2	1.2
C4+, mol%	0.4	0.0–2.1	0.0–2.1	0.1	0.6
$CO_2 + N_2$, mol%	2.6	0.0–15.1	0.0–10.0	1.0	4.3
Wobbe Index, Btu/scf	1336	1201–1418	1201–1418	1331	1357
MN	90.0	34.1–96.2	73.1–96.2	84.9	93.5

[1] PA refers to propane–air peak shaving during peak demand periods.

Existing CNG Fuel Quality Standards

In general, pipeline gas quality standards do not match fuel specifications set forth by either engine manufacturers or regulatory bodies such as CARB. In fact, there is no nationwide pipeline gas specification. CARB is the only U.S. regulatory entity that has established a commercial fuel quality specification for NG.

The lack of clear and reasonable gas quality standards is, by many accounts, impeding the proliferation of CNG and NGVs. Engine manufacturers have greatly improved engine designs in the past decade to accommodate a wider range of fuel compositions, but without a nationwide pipeline standard and without a robust CNG market, CNG suppliers have been unable to consistently deliver the fuel quality required to support a developing CNG market.

Anecdotally, other fuels markets have had to wrestle with the problem of chasms between manufacturer fuel specifications and available fuels. This has happened largely behind the scenes in the world of gasoline and diesel engines. There has always been a tension between the OEMs and the fuel providers. The OEM's ideal is to have a very tight fuel specification to preclude effects of variable fuel composition on their engines. The fuel suppliers cannot generally provide that high level of quality without charging an objectionable premium cost. In the case of mature gasoline and diesel markets, this balance of power results in the two factions agreeing to a compromise.

In the case of CNG, there is not yet a host of major fuel suppliers in the market to push back against the demands of the OEMs. This leads to an unbalanced approach to fuel specifications. The authors of this report spoke with these OEMs and upfitters, including Cummins Westport, Westport HD, Landi Renzo, and BAF. These companies told the authors that strict fuel specifications are required for engine warranty purposes because CNG fuels have the potential to vary so greatly. It is the OEM's position that no engine design could adequately accommodate such widely ranging fuel compositions without inducing damage to the engine or accelerating the replacement schedule of various consumables.

Following is a summary of the major relevant CNG fuel specifications in use in the United States today.

40 Code of Federal Regulations (CFR) 79.55 Base Fuel Specifications (EPA)

EPA prescribes a set of base fuel specifications for each major type of fuel used in transportation in the United States. This base fuel specification is not meant to declare a required specification for fuel sold but, rather, sets a standard fuel upon which tailpipe emissions should be measured. Methane base fuel is defined as a gaseous motor vehicle fuel marketed commercially as CNG, whose primary constituent is methane. According to CFR 79.55, methane base fuel must meet the specifications listed in Table 14.

Table 14. Methane Base Fuel Specification, 40 CFR 79.55

Component	Value
Methane, mol%, min.	89.0
Ethane, mol%, max.	4.5
Propane and Higher HC, mol%, max.	2.3
C6 and Higher HC, mol%, max.	0.2
Oxygen, mol%, max.	0.6
Sulfur (including odorant additive) ppm_v, max.	16
Sum of CO_2 and N_2, mol%, max.	4.0

Society of Automotive Engineers (SAE) J1616 – Recommended Practice for CNG Vehicle Fuel

SAE has published a recommended CNG specification, summarized in Table 15, which presents important physical and chemical characteristics of CNG vehicle fuel and describes test methods for evaluating these characteristics. It does not, however, take the CARB approach to fuel specification by hydrocarbon species. Instead, it leans heavily on the Wobbe index as a measure of fuel quality and provides recommendations on nonfuel contaminant content.

Table 15. SAE J1616 CNG Specifications

Component	Value
Water Content	Note[1]
CO_2	3.0%, max.
S and Sulfur Compounds	8–30 ppm, max.
O_2	Note [2]
Particulate Matter	Minimized
Pressure Hydrocarbon Dewpoint Temperature	Note [3]
Wobbe Index	48.5–52.9 MJ/m³

[1] The local dew point temperature of the fuel should be defined as 5.6°C below the monthly lowest dry-bulb temperature at the maximum operating cylinder pressure.
[2] The oxygen level must not produce a mixture within the flammability limits of NG.
[3] The composition of NG should be such that the original gaseous storage volume will form less than 1% of a liquid condensate at the lowest ambient temperatures and gas storage pressure between 5.5 and 8.3 MPa at which maximum condensation occurs, depending on gas composition.

California Specifications for CNG (California Code of Regulations, 2012)

The CARB CNG fuel specification takes a conservative approach and prescribes fuel content by hydrocarbon species as well as by maximum levels of nonfuel contaminants. It does not address fuel heating value directly but, rather, prescribes a fuel mixture that could be used to derive a methane number or Wobbe index.

CNG cannot be sold or supplied in California unless it meets the specifications in the Table 16. Industry sources indicate that the commercially available CNG fuel in California may not meet the California specification, and the issue may have to be reviewed in the future (U.S. Energy Information Administration, 2012a). In fact, since 2010, CARB has been considering a major redefinition of these CNG specifications to instead rely almost solely on methane number as the key specification. This change is being advocated by major CNG engine manufacturers and their trade associations.

Table 16. CARB Specifications for CNG

Component	Value, mol%, unless otherwise noted
Methane	88.0%, min.
Ethane	6.0%, max.
C3 and Higher HC	3.0%, max.
C6 and Higher HC	0.2%, max.
Hydrogen	0.1%, max.
Carbon Monoxide	0.1%, max.
Oxygen	1.0%, max.
Sum of CO_2 and N_2	1.5–4.5%, range
Water	[1]
Particulate Matter	[2]
Odorant	[3]
Sulfur	16 ppm by vol., max.

[a] The dew point at vehicle fuel storage container pressure must be at least 10°F below the 99.0% winter design temperature listed in Chapter 24, Table 1, Climatic Conditions for the United States, in the American Society of Heating, Refrigerating and Air Conditioning Engineers (ASHRAE) Handbook, 1989 fundamentals volume.

[b] The CNG must not contain dust, sand, dirt, gums, oils, or other substances in an amount sufficient to be injurious to the fueling station equipment or the vehicle being fueled.

[c] The NG at ambient conditions must have a distinctive odor potent enough for its presence to be detected down to a concentration in air of not over 1/5 (one-fifth) of the lower limit of flammability.

Recent Movement Toward NGVs

Corporate Push for NGV Fleet Conversion

A small but significant number of American corporate entities have committed to converting substantial portions of vehicle fleets to CNG and LNG. The reasons for this push vary by case, but in general can be attributed to corporate "green" strategy, fuel cost savings, government incentives, and regulatory pressure in certain states. A small sampling of recent and ongoing fleet conversions to CNG and LNG is presented in Table 17. This list is not comprehensive but, rather, is intended to convey that many major U.S. corporations are acting on motivations to adopt NGV technology into their fleets and business strategies.

Table 17. A Sampling of Recent and Ongoing Major Fleet Conversions to CNG

National Fleets	Regional Fleets
AT&T – Committed to 8000-NGV fleet	Silver Eagle
Verizon – Recently Converted 501 New Vans to CNG	Enbridge
Federal Express	Chesapeake Energy – committed to converting nearly 5000 fleet vehicles to NGV
UPS – Operates 1100+ NGVs	Republic Services – operates 226 NGVs
Waste Management – Operates 1000+ NGVs	

The Impetus of High Gasoline Prices

Available data indicate that CNG prices have experienced lower volatility over the past decade when compared to gasoline and diesel fuels. On an energy equivalent basis, during the same period, CNG has also been significantly less expensive than gasoline and diesel. Figure 24 summarizes nationwide average price data over the past 12 years. If these data are analyzed regionally, larger or smaller separations between CNG prices and gasoline/diesel prices can be presented, but a similar gap exists.

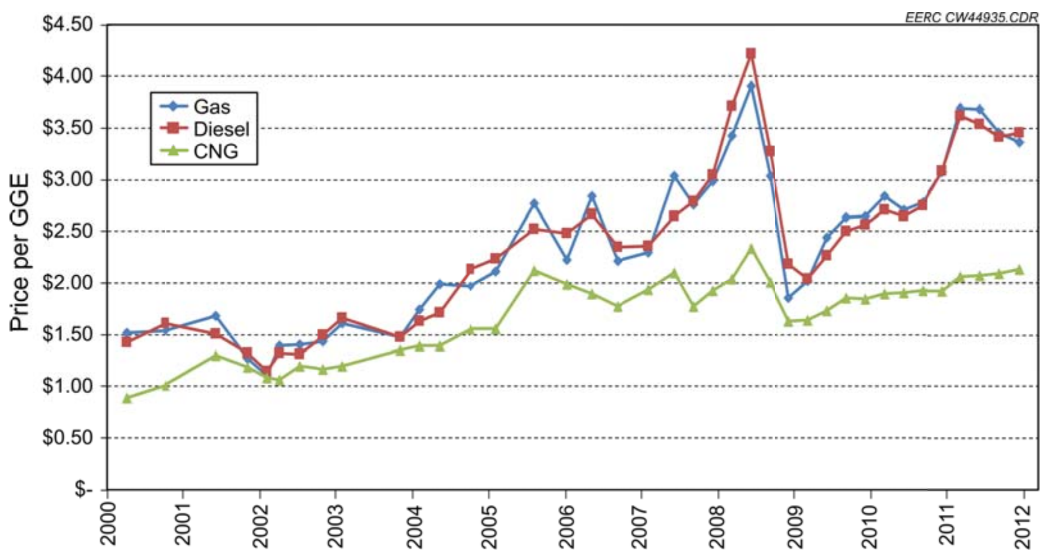


Figure 24. Historical CNG price comparison (Alternative Fuels and Advanced Vehicles Data Center, 2012).

These data seem to indicate a strong economic case to consider CNG as an alternative fuel. However, caution must be exercised in interpreting these data. World LNG trade, domestic production rates of NG, and refinery operations all have dramatic impacts on the price differentials shown in Figure 24. Taking all of these factors into account, the U.S. Energy Information Administration (EIA) still predicts in Figure 25 that the gap between crude oil and

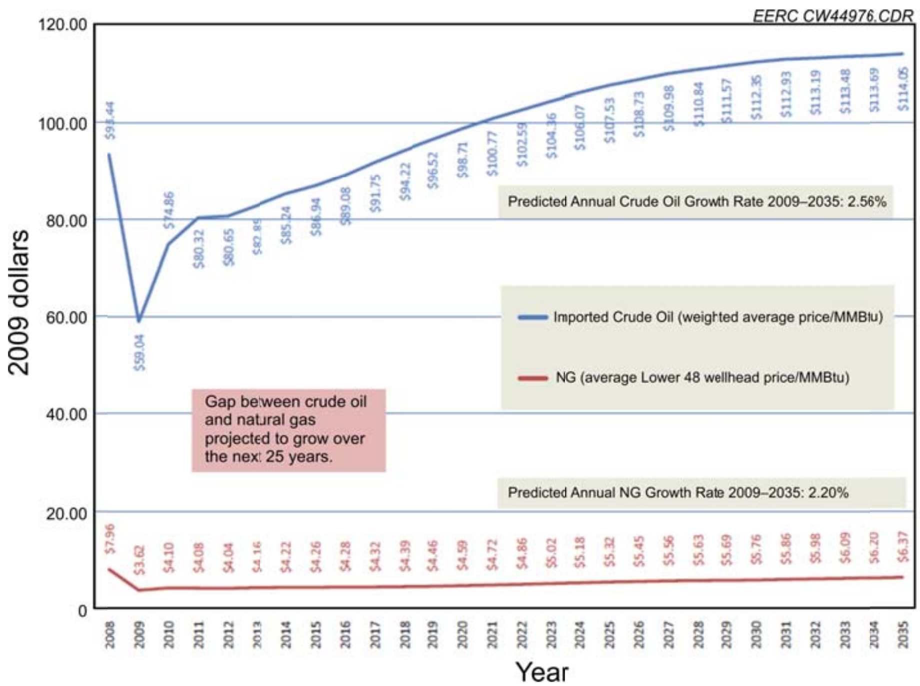


Figure 25. EIA projections for crude oil vs. NG pricing.

natural gas prices will continue to grow through at least 2015. Because of the direct connection between crude prices and gasoline/diesel prices, it can be inferred that the gap between gasoline/diesel and CNG will also continue to grow.

Given this information, a solid case can be built to state that large fleets can capitalize on the opportunity to use less expensive CNG fuel. A diesel fleet accumulating 1 million miles/year could save $135,000/year in fuel costs, as shown in Table 18.

Table 18. Million-Mile Fleet Fuel Savings

National Average CNG Cost, 5/1/12 (GGE)[1]	$1.89
National Average Diesel Cost, 4/30/12	$4.073
Diesel Cost, GGE basis	$3.65
National Average Regular Gasoline Cost, 4/30/12	$3.830
Million-Mile Light-Duty Fleet Fuel Savings over Gasoline, adjusted to an energy basis[2]	$97,000
Million-Mile Heavy-Duty Fleet Fuel Savings over Diesel, adjusted to an energy basis[3]	$135,300
Million-Mile Heavy-Duty Fleet Fuel Saving over Diesel, Adjusted to an energy basis[4]	$305,965

[1] Source: www.cngprices.com.
[2] Assumes 20 mpg.
[3] Assumes 13 mpg.
[4] Assumes 5.5 mpg.

A Distributed Model Suitable for Small-Scale Bakken Associated Gas Opportunities

Opportunities to use wellhead gas to produce CNG fuel in the Bakken development may be plentiful because of the rapid and prolonged pace of development, but each opportunity exists for only a limited time. In general, a maximum of 1 year passes between the time a new well is completed and the time at which gas-gathering pipeline is brought to the first well on the new location. During this time, associated gas is typically flared. After this time, the assumption is that it would be difficult to compete with the economics of gathering and centralized gas processing, especially given that “pipeline quality” does not always equate to CNG quality. Additional polishing is often required to convert pipeline gas to CNG gas, given the wide variations in pipeline gas composition.

Prior to injection into pipelines, Bakken associated gas is treated in centralized gas-processing facilities connected to wellheads by vast networks of gathering pipelines. Accomplishing the same (or higher) level of gas processing at the wellhead would require 1) miniaturization of gas purification technologies, 2) great reduction in price of each purification function for the smaller scale, and 3) mobile purification/compression/dispensing systems capable of being quickly set up at one location then mobilized and moved to new locations on a regular basis and at intervals of less than 1 year.

A natural economy of scale exists at larger, centralized gas-processing plants. Desiccant towers, desulfurizer units, NGL extraction, and fractionation towers are traditionally made most economical when they are built to process large amounts of gas. The inherent nature of scale works against cost-effective size reduction. It is, indeed, a challenge to miniaturize these systems for the purpose of achieving the same level of processing at the wellhead. There are, however, enabling techniques to be investigated to work around this phenomenon of scale.

NGL Removal and Storage

The removal of NGLs from the rich gas greatly increases the economic feasibility of a CNG project and reduces the loss of resource when flaring is necessary. Based on modeling done as part of this study, the EERC concluded that removing the NGLs (specifically butane and heavier constituents and a portion of propane) can be accomplished with chilling and JT cooling operated at −20°F and 200–1000 psi. Once the NGLs have been separated and stabilized, they are pumped to on-site storage tanks.

At an estimated NGL removal rate of 4 gallons/Mcf (from 1000 Mcf/day of rich gas) the daily production of NGLs would be approximately 4000 gallons of NGLs per day. Based on this NGL production number and a desire to have 2 weeks worth of storage capacity, the required storage capacity would be approximately 56,000 gallons (1300 bbl). NGLs would need to be stored on-site at a minimum pressure of 200 psi to maintain NGLs in the liquid phase.

Based upon discussions with industry representatives, the capital cost for the NGL removal and storage system is estimated to be $2,500,000. This capital cost includes the necessary compression to take the rich gas from the heater/treater at 35 psi up to 200–1000 psi delivered to the NGL removal system as well as the cost for four 400-bbl NGL storage tanks.

The CNG scenario analyzed in this study employs an NGL removal system since the authors believe it adds significant value to the project and improves the economics. Since the capital cost for this system is presented separately, it is simple for the reader to remove it from the capital equation if deemed unnecessary. Figure 26 shows a block flow diagram of the NGL removal system as an example.

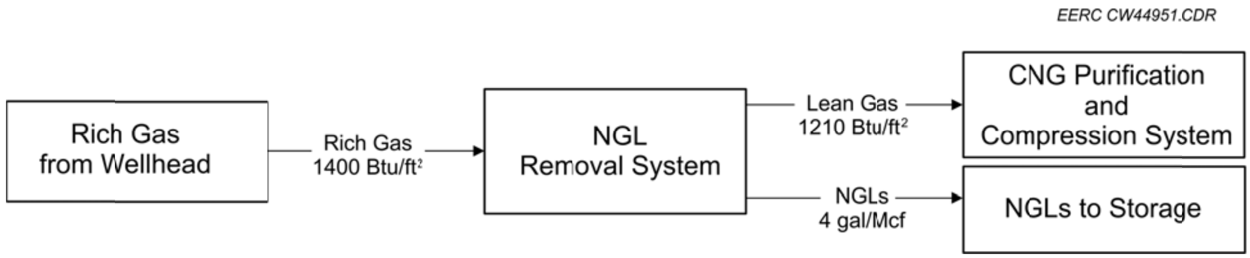


Figure 26. NGL removal system block flow diagram.

A Notional Mobile CNG Fuel-Processing/Compressing/Dispensing Station

The CNG application presents a unique set of design challenges not entirely analogous to the other applications explored in this study. While the power generation application requires very little gas cleanup, CNG instead requires a significant level of polishing to achieve CNG-quality fuel and avoid problems with the dispenser compressor, engine, and vehicle fuel system. Therefore, it is envisioned that the CNG application will require an advanced, small-scale, mobile gas-processing system instead of a simple NGL extraction system. This distinction introduces significant differences in the approach to analyzing the technical and economic viability of a mobile CNG system to capitalize on wellhead gas opportunities relative to the distributed power generation case or the chemical production case.

If a small, mobile gas-processing system can be developed to remove water, CO_2, NGLs, and sulfur from rich associated gas, the resulting fuel-quality natural gas can be compressed and dispensed to fill automotive fuel tanks. The compression and storage portion of system development has been accomplished by companies such as IMW/Clean Energy, General Electric, BRC FuelMaker, Agility Fuel System, and others. These companies offer various mobile refueling systems capable of providing an off-the-shelf approach to CNG for NGVs. Typically, these systems are deployed where NG distribution pipelines provide adequate gas quality and supply. However, they could also be used along with small-scale gas purification systems to provide NGV fueling infrastructure upstream of typical gas-processing facilities and at wellheads or gathering pipelines where vehicle access can be accommodated.

One self-contained, fleet-ready, and Bakken-ready mobile fueling system is produced by IMW Industries. The new IMW mobile CNG refueling system (shown in Figure 27) features on-board fueling capability for 10 vehicles simultaneously in time-fill mode or for two vehicles in fast-fill mode. It is designed for use with a portable generator (or site power) and an on-site utility gas supply connection. Onboard compressors are designed to accept a range of clean gas inlet pressures, compress the gas to 3600 psig, and deliver the gas through a hose and CNG fitting to a vehicle's tank.

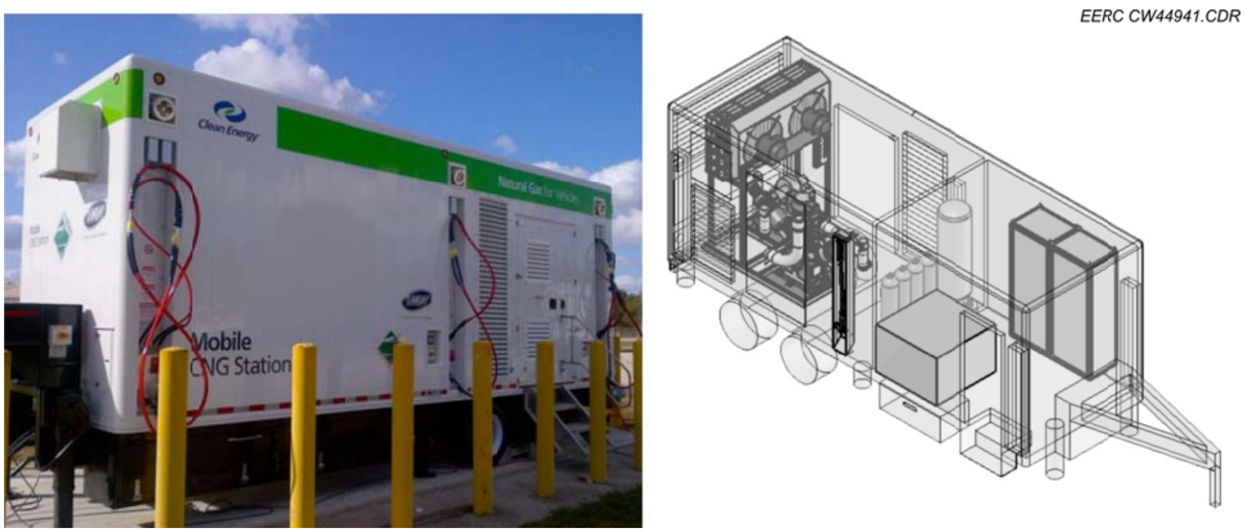


Figure 27. IMW mobile CNG refueling system.

Budgeting details for this conceptual system are presented in the economics section of this report.

General Electric's CNG-in-a-box compression/dispensing product solution (shown in Figure 28) compresses pipeline NG on-site at an industrial location or at a traditional automotive refilling station. This system could also be adapted to the purposes discussed in this report, but the system is not deemed as mobile as the IMW solution. It is a quick-installation system, but not truly mobile for repeated rapid relocation. Key features include the following:

- The gas compression, storage, cooling, drying, and controls are easy to ship and maintain because of the compact in-a-box design.
- The units come in two configurations, an 8-ft × 20-ft container or an 8-ft × 40-ft container.
- The fuel dispenses at a rate of about 7 GGE/minute.

Figure 28. General Electric's CNG-in-a-box compressing/dispensing package.

Land Acquisition

Analysis of the CNG/LNG scenarios assumed that the placement of the CNG/LNG systems and their related components would not require the purchase or rental of additional land area.

Economics of the Use of Associated Gas to Fuel NGVs

Previous Economic Models

A frequently cited landmark study on the economics of NGVs was completed by the National Renewable Energy Laboratory (NREL) (Johnson, 2010). This study split the economic model for NGVs into the following baseline parameters:

- CNG station cost
- Fleet scenarios
- Maintenance and operation costs
- Fuel price and rate of increase
- Taxes and incentives
- Financing
- Garage cost
- Project life and salvage value

Further, it assumed three types of municipal fleets – transit buses, school buses, and refuse trucks.

The study concluded that predicting whether a particular CNG project is financially sound is challenging. Decisions made on equipment purchases, capital upgrades, and fuel contracts have long-term impacts on the operational success of the fleet. It also concluded that fleets could be classified as "resilient," "marginal," or "no-CNG," as detailed in Figure 29. Resilient fleets tend to use large quantities of fuel and are profitable enough to be resilient to multiple changes in the fleet parameters previously listed. Table 19 shows a spread of fuel usage among various types of CNG vehicles, and thus the table attempts to prioritize vehicle types according to potential profitability to a user willing to convert to CNG.

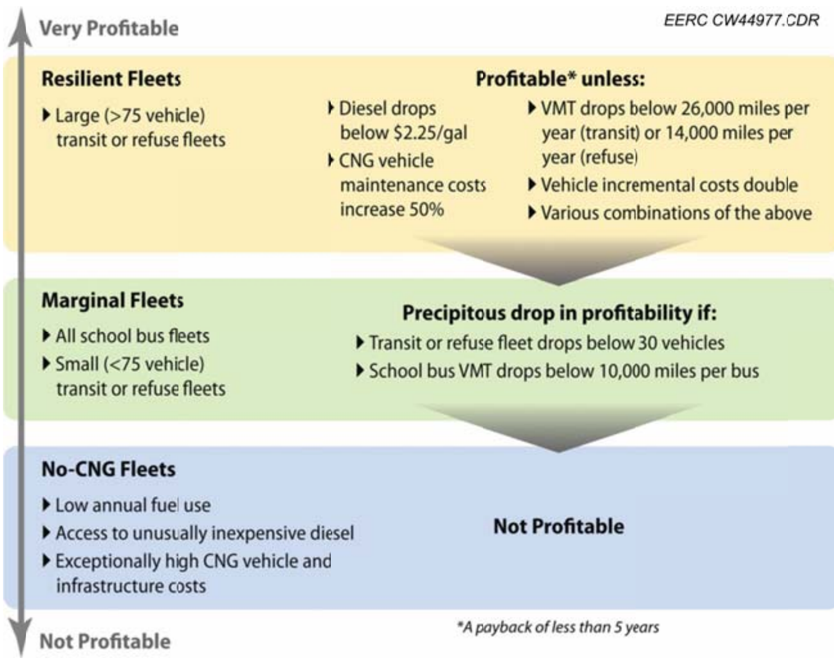


Figure 29. Largest factors affecting the profitability of marginal and resilient fleets (Johnson, 2010).

Table 19. Best Vehicles for CNG (Johnson, 2011)

Vehicle Type	Annual Fuel Use, GGE[1]	Required Range	Available Refueling Time	Refueling Equipment
Transit Bus	11,906	Short	Short	Fast CNG
Refuse Truck	9877	Short	Short	Fast CNG
Paratransit Shuttle	3434	Short	Short	Fast CNG
Taxi	3392	Short	Short	Fast CNG
School Bus	1896	Short	Long	Slow CNG
Delivery Truck	1609	Short	Variable	Fast/slow CNG
Police Cruiser	1423	Long	Short	Fast CNG
Light-Duty Vehicle	558	Variable	Variable	Slow CNG

[1] Source: Alternative Fuels and Advanced Vehicles Data Center, www.afdc.energy.gov/afdc/data/vehicles.html.

Key NREL Report Conclusions

In summary, the NREL report concluded the following:

- Decisions made on equipment purchases, capital upgrades, and fuel contracts have long-term impacts on the operational success of the fleet.
- Larger transit and refuse fleets (75+ vehicles) tend to be profitable and resilient to variations in project parameters.
- School fleets and small transit/refuse fleets tend to be marginal.
- Diesel prices are a powerful indicator of profitability given that NG prices are relatively consistent. A school bus project appears to only make economic sense once diesel prices approach \$4/gallon for 100-bus fleets and \$5/gallon for 50-bus fleets.
- Project success is very sensitive to vehicle maintenance costs.
- Tax issues have a strong influence on profitability.
- The cost of the station has a significant influence on the profitability of marginal projects.
- Factors that do not have much effect on project profitability over the range tested are:
  - Efficiency difference between CNG and diesel engines (−25% to +10%).
  - Change in vehicle/project life (10 years to 20 years).
  - Electricity prices (50% and 150% baseline).
  - Maintenance costs for the CNG station (50% and 150% baseline).
  - Garage upgrade (for minimal-upgrade scenario).
  - Number of new attendants/hostlers (fewer than two to more than four personnel).

A Model for Use of Bakken Gas in NGVs

Many of the cost factors that must be analyzed to produce a valid economic assessment of the Bakken region's CNG/LNG opportunities are well understood. However, this study lacks sufficient data to determine costs associated with a foundational component of a valid economic assessment – costs related to the technology required to purify the rich, wet associated gas into engine manufacturer-approved CNG/LNG fuel. Few, if any, microscale distributed systems exist that are capable of separating NGLs, sulfur, and water from the rich Bakken associated gas economically to polish the resource to CNG-quality fuel. None were identified by this study. That is not to say that larger systems could not be adapted, but to date, this has not been a market opportunity, so no commercially available systems exist.

Liquefaction of natural gas to produce LNG fuel is even more challenging in terms of cost, especially at the small scales being investigated within the context of this study. After a brief examination, LNG did not surface as an area of emphasis. Reasons for not including LNG as an area of emphasis for this study included:

1. Significantly increased capital costs of liquefaction equipment over CNG equipment.

2. Difficulties in miniaturizing and mobilizing liquefaction systems for use at the wellhead.

3. Additional precompression removal of natural gas liquids required to provide suitable feedstocks to liquefaction process.

One of the objectives of the study was to determine a palette of potentially viable technologies that could be scaled down to address distributed-scale gas purification for CNG production. The technologies outlined in a previous report section are all candidates for this scaling effort. The cost analysis for fuel preparation costs will, therefore, only outline a boundary condition for costs that create an economically feasible scenario.

Scale of Potential CNG Consumption Relative to Bakken Associated Gas

A fleet traveling 1 million miles annually would consume approximately 15,000 Mcf/year, or 23,000 scf of CNG per day (assuming 15 miles/GGE). Comparing this against the gas production rates shown in Table 3, it is evident that even large NGV fleets would not consume significant quantities of Bakken associated gas relative to the amount of gas available. The CNG economic assessment will necessarily start from an assumed, reasonably sized fleets, and project where the economic breakeven point will be, given a set of assumptions. It will then present sensitivity analyses based on various fleet gas usage factors.

Fuel Preparation Costs

Perhaps the largest unknown in this economic analysis is the cost of fuel purification and preparation for compression and dispensing operations. Because the North Dakota Bakken Formation associated gas is a rich gas, commercial, off-the-shelf, distributed-scale technology is not readily available. Costs were estimated based upon EERC experience in gas-processing technologies from other technology sectors. $2.5 million was assumed for a small-scale gas-processing system that can be made mobile to work at sites of opportunity in the Bakken region. This cost would naturally decrease as additional units are manufactured, but development costs would necessarily need to be captured in the first sale.

A by-product of fuel purification is the NGL stream produced. This NGL stream has value and must be factored into the CNG economic analysis. Throughout the various applications discussed in this report, the authors use the assumptions listed in Table 20 to represent revenue generated from an NGL removal system and subsequent sale of NGLs. This represents additional revenue in the CNG economic model.

Table 20. Assumed NGL Revenues Associated with CNG Production

Product	Quantity	Assumed Value	Daily Revenue	Annual Revenue[1]
NGLs	2400 gpd	$1.00/gal	$2400	$700,800

[1] Assumes 80% annual system availability.

For the purposes of this study, the cost of associated gas has been set at zero. The actual cost of this resource will be highly dependent upon the business arrangement.

Station Costs

This report assumes, based upon findings in the NREL report (Johnson, 2010), that high throughput, rapid fueling stations will serve the most economically feasible vehicle fleet scenario – that of a high-mileage fleet with significant fuel consumption. This assumption drives a baseline including a fast-fill station capable of significant fueling throughput and rapid turnaround of vehicles upon fueling.

This fueling station must also be mobile to move to where uncaptured associated gas exists. Even if it is assumed that the gas converted to CNG can be obtained from gathering lines (thus alleviating the requirement to move as frequently as would be necessitated by stationing at wellheads that are eventually connected to gas-gathering systems within a year), it could be argued that the station would need to remain mobile to serve the moving fleets of vehicles following the expansion of the Bakken play. This would apply equally to field service vehicles, transit buses, and personal vehicles. Given this set of assumptions, a fueling station configuration can be defined. The mobile CNG fueling trailer offered by IMW Industries serves as an effective example. IMW Industries has provided the costing information in Table 21 (Damiani, 2012).

Table 21. Estimated Mobile Refueling Station Costs (Damiani, 2012)

Mobile Fueling Station Cost Component	Lease	Purchase
Refueling Trailer	$13,000 per month	$500,000
Siting Costs	$10,000 per site	
Electrical Costs[1]	$0.10/GGE[2]	
Maintenance Costs	5% of equipment costs per annum	

[1] North Dakota low electrical rates considered.
[2] Ybarra, 2007.

Thus IMW Industries and the EERC estimate that in a lease situation, a project would expend approximately $15,000 per month to lease, site, operate, and maintain the IMW mobile fueling station, assuming one site a year and a fleet refueling with 72,000 GGE (developed in Table 22). Over a 10-year project lifespan, a lease would cost approximately $1.8 million. A purchase situation would alternately cost approximately $750,000 (not including financing costs), using the same assumptions. Given the anticipated long-term refueling needs, the remainder of the economic evaluation was performed based on the purchase of a refueling system.

Table 22. Yearly Costs vs. Fuel Savings

Yearly Financing Payments	$908,325
Additional Yearly Fueling Trailer-Siting Costs	$10,000
Yearly Fueling Trailer Maintenance Costs	$50,000
Yearly Electricity Costs	$7,200
Yearly Gas Resource Payments	$0
Less Yearly Revenue from NGL Recovery and Sale (Table 20)	($700,800)
Net Yearly Costs	**$274,725**
Yearly Cost Savings in Fuel, assuming comparable fuel mileage	
Number of Vehicles	60
Vehicle Miles Traveled (VMT) per Vehicle	18,000
VMT Total	1,080,000
Mileage, miles/GGE	15
GGE Consumed	72,000
Gasoline Cost, $/gal	$3.70
CNG Cost, $/GGE	$2.45*
Net Cost Savings on an Energy Basis, $/GGE	$1.25
Net Yearly Cost Savings for Total Fleet VMT	**$90,000**

* $2.45 CNG price is a high quote of national pump price samples from www.cngprices.com on April 19, 2012.

Vehicle Costs

For the sake of this model, it is assumed that the fleet of vehicles would consist of 60 converted Ford F-250 pickups used as field service vehicles. The costs for these conversions are readily available from each manufacturer. As an example, BAF Technologies provides this conversion package at a cost of $12,800/vehicle. This includes upfit costs for a bifuel CNG–gasoline engine or a dedicated CNG engine plus transportation to a local Ford dealer. It does not include state and local taxes on vehicle purchases. For 60 conversions, vehicle costs would amount to $768,000.

O&M Costs

NGVs are often assumed to have lower maintenance costs compared to diesel and gasoline engine vehicles. NG burns cleaner (fewer carbonaceous deposits), so its combustion results in less wear on mechanical components of the engine and extends the time between tuneups and oil changes. Anecdotally, some fleet operators have reduced maintenance costs by as much as 40% by converting their vehicles to CNG. Oil changes are recommended every 10,000–25,000 miles, depending upon the vehicle make and how the vehicle is used. This is compared to every 3000–5000 miles for the gasoline engine.

Despite this anecdotal indication, little evidence is found in the literature to support this assumption. In fact, Watt (2012) and World Bank (2001) state that maintenance may actually be more expensive, compared to diesel maintenance, for the following reasons:

- NGV parts are generally more expensive because of lower volumes.

- NGV engine users have reported reduced reliability of NGV engines, although it should be noted that this may be a function of engine vintage. Manufacturers are sure to state that 1990s engines were in the early stage of their product development cycle and will continue to improve.

Therefore, this study will assume that maintenance costs do not vary significantly from gasoline or diesel engines in similar use situations. This approach is validated by the approach taken independently in the NREL report discussed previously (Johnson, 2010).

Fuel Price

The value of stranded associated gas is difficult to assess. The focus of this report was to identify economical utilization of fuel resources that are otherwise being flared (unmonetized). The report scope was expanded to include not only wellhead associated gas that is currently flared, but also gathered associated gas, if there is potential to use that gas locally and in an economically efficient manner.

This report takes the tack of proposing a reasonable bounding fuel cost for the model (top-down, in many respects). This fuel price must be a value that is supported by market demand, is comparable to prices regionally and nationwide, and does not artificially push the economic analysis out of bounds.

A fuel price of $2.45/GGE represents a reasonable marker for the following reasons:

- Although higher prices are reported at fueling stations elsewhere in the nation, this value still allows for a cost premium that can be applied toward higher gas-processing costs assumed to be relevant to smaller, distributed fuel processing.

- Although lower prices are reported at fueling stations elsewhere, this value still reflects the fact that no distribution costs are incurred.

- Although this price is higher than reported at fueling stations elsewhere, this price point potentially still represents a large fuel cost savings for medium-sized fleets.

Taxes and Incentives

A myriad of state incentives for NGVs exists, but they vary greatly by state. Currently, there are no North Dakota State incentives for NGVs or NG fueling stations.

The Energy Policy Act of 2005 (§1341, Publication L, No. 109-58) provided income tax credit when NGVs were purchased. However, this tax credit was allowed to expire in December 2010. Similarly, a fuel excise tax credit to sellers of CNG or LNG fuel expired in 2009, although the credit was then extended until August 2011 as part of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (PL 111-312). No federal incentives for NGVs or NG fueling stations currently exist. Finally, income tax credits for installation of NGV fueling infrastructure expired in December 2010 and were extended for 1 year as part of the Tax

Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (PL 111-312). No federal incentives currently exist to promote NGV purchase and use, but in January of 2012, President Barack Obama renewed a conceptual push for increased use of NGVs, sketching out plans for additional federal tax credits and other incentives (Sanati, 2012). Details of this plan were developing at the time of this report.

Fuel taxes are examined as follows and summarized in Table 23 only to verify that they are not excessive to the point that they necessarily inflate the previously described assumed fuel cost. A fuel cost of $2.45/GGE less $0.413/GGE leaves $2.037/GGE for nontax fuel costs, including O&M of the fueling station, siting costs, amortization costs, and fuel-processing costs. This is still a moderate price point when compared with other tax-inclusive price points across the nation and is thus deemed a conservative but reasonable price point.

Table 23. Taxes on CNG in North Dakota

Tax Component	Addition to Fuel Price
Federal CNG Excise Tax (reference IRS Form 720)	$0.183/GGE
North Dakota State Sales Tax on CNG	Exempt
North Dakota Special Fuels Excise Tax	$0.23/GGE
Total Tax Add to CNG	$0.413/GGE

Costs of Financing

Using cost estimates described previously, a simple bounding analysis can be completed to determine a net annual fuel cost savings that is required to economically justify implementation of CNG fleet conversion, including installation of support infrastructure. There are many sensitivity studies that could be performed, but only basic data with many cost assumptions are provided here. Insurance and permitting costs are not included because of the difficulty in obtaining estimates on such an insufficiently defined, hypothetical case. These costs would likely be small relative to other implementation costs.

The analysis first approximates the up-front implementation costs anticipated for such a project. The up-front costs are summarized in Table 24. This analysis shows that approximately $6.8 million must be rolled up into the first-year expenses of a fleet conversion project. These costs also represent additional costs that would not be incurred without the conversion project.

Table 24. Up-Front CNG Fleet Implementation Costs

Upfront Cost Component	Cost, US$
Mobile Refueling Trailer Purchase (two trailers)	$1,000,000
First Year Siting Costs (four sites)	$40,000
Vehicle Upfit Cost (60 vehicles)	$768,000
Gas Processing Unit (two units)	$5,000,000
Total Up-Front Implementation Costs	**$6,808,000**

Next, a simple look at amortization costs is summarized in Table 25, assuming a 6% interest rate. No time value of money is accounted for in this simple analysis. This calculation shows that $6.8 million in up-front costs could be financed for approximately $2.3 million in interest, totaling approximately $9.1 million in principal and interest.

Table 25. Amortization Costs

Equipment and First-Year Costs	$6,808,000
Finance Processing Costs	$10,000
Total Amount Financed	$6,818,000
Interest Rate	6%
Finance Period	10 years
Estimated Monthly Payment	$75,693.78
Total Interest Paid	$2,265,253
Total Principal + Interest	**$9,083,253**

These values provide input for the real goal of this analysis, which is to illustrate the yearly savings in fuel costs required to justify the CNG conversion project on strictly economic value. The amortization summarized in Table 25 results in a $75,893 monthly payment toward principal and interest. Over the course of a year, this amounts to $910,723 in payments. An estimate of financing costs is included in Table 22 along with costs incurred during subsequent years of the project to arrive at a net yearly project cost. This is then compared against the yearly savings from reduced fuel prices.

It is apparent from the calculations summarized in Table 22 that a 60-vehicle fleet will not pay for itself in fuel savings alone, even if rich gas resource purchase costs are ignored. Other noneconomic factors would have to be included to justify this conversion project. If the analysis is pursued further to investigate sensitivities to the primary input parameters of vehicles, VMT, mileage, and relative fuel costs, the situations summarized in Table 26 can provide the economic justification required. In this table, inputs are found in bold cells, calculations in nonbold cells. The variables changed from the baseline presented in Table 22 to drive the net cost savings for total fleet VMT to be equal to net yearly costs presented in Table 22 are highlighted in bold italic text in Table 26. This sensitivity analysis shows that a significantly larger fleet than that presented in the baseline case in Table 22 needs to be considered to make such a project economically feasible.

Table 26. Other Economic Scenarios that Make Fuel Savings Equal to Net Yearly Costs

Number of Vehicles	**164**	**120**	**120**	**120**
VMT per Vehicle	18,000	**24,600**	**18,000**	18,000
Total VMT	2,952,000	2,952,000	2,160,000	2,160,000
Mileage, miles/GGE	15	15	**10.98**	15
GGE Consumed	196,800	196,800	196,721	144,000
Gasoline Cost, $/gal	$3.70	$3.70	$3.70	**$3.71**
CNG Cost, $/GGE	$2.45	$2.45	$2.45	**$2.00**
Net Cost Savings on an Energy Basis, $/GGE	$1.25	$1.25	$1.25	$1.71
Net Cost Savings for Total Fleet VMT	$246,000	$246,000	$245,902	$246,240

A large driver in this simple model (and a large unknown) is the cost of the gas-processing unit. With no commercial off-the-shelf packages available for this type of rich gas processing to CNG-quality fuel gas, a reasonable estimate of $2.5 million was used. If this analysis is completed with a $500,000 price for the gas-processing unit instead, the numbers change dramatically. Total up-front implementation costs become $2,808,000. Total principal and interest become $3,754,269, including $936,269 of interest. Net yearly costs instead become net yearly revenue if NGL sales are accounted for (again, ignoring rich gas resource purchase costs). The net yearly revenue becomes $258,173. Thus it can be determined that:

- The CNG purification system cost will be a major driver of the economic justification for CNG use.

- The business agreement to purchase the rich gas resource will, of course, be critical to the economic justification.

Evaluation Summary

While there may be several other drivers to warrant the use of CNG in the Bakken region, economics alone will most likely not justify conversion of medium-sized fleets of vehicles to CNG if a distributed CNG refueling approach is taken. The economics of small-scale, distributed gas processing seem to be the major driver pushing costs per VMT to high levels. Several other studies in the literature have concluded that economic justifications can be made for CNG if stationary fueling systems are used in conjunction with large fleets of vehicles. The economies of scale involved in centralized processing and gas distribution are difficult to improve upon.

If noneconomic justifications for CNG fleet conversion can be made on a case-by-case basis, technology exists that could be adapted to suit the needs of any particular refueling scenario. This study, however, reveals that some additional gas processing would likely be necessary even if the gas resource is obtained from existing pipeline infrastructure in North Dakota. A few exceptions exist, depending upon the location of the draw from the pipeline and the pipeline from which the gas is drawn. However, much of the pipeline gas in North Dakota does not meet minimum specifications for NGV use.

APPLICATION II – ELECTRIC POWER GENERATION

Background

Current Electrical Generation

North Dakota possesses many abundant energy resources—coal, oil, natural gas, wind, hydroelectric, and biomass. Of these, the electrical generation profile of North Dakota currently comprises three primary sources: coal, wind, and hydroelectric; in 2010, these represented 64%, 25%, and 9%, respectively, based on nameplate capacity (U.S. Energy Information Administration, 2011). Because of sparse population and low in-state electrical consumption, between 60% and 70% of the electricity generated in North Dakota is exported. Table 27 provides a comparison of North Dakota's electrical generation to its neighboring states.

Table 27. Nameplate Electrical Generation Capacity as a Percentage of Total for North Dakota and Neighboring States (U.S. Energy Information Administration, 2011)

	North Dakota, %	Montana, %	South Dakota, %	Minnesota, %
Coal	64	44	13	32
Hydroelectric	25	43	42	1
Wind	9	6	17	12
NG	<1	5	21	35
Petroleum	1	1	8	6
Nuclear	0	0	0	11

As discussed in the Oil and Gas Production Section, the rapid development of the Bakken Formation in the Williston Basin for oil has produced an excess of NG which currently exceeds the processing capacity in the area. Flaring the excess NG has become an issue until collection infrastructure and processing capacity are built out. For the purposes of this study, this "stranded" gas is being called nontraditional NG, a term that is intended to describe all NG that is upstream of the gas-processing facility.

When evaluating the use of nontraditional NG as a fuel for distributed power generation, the following considerations are foremost:

- Scale (0.5 to 10 MW)
- Fuel flexibility (rich gas with minimal processing)
- Maturity (commercially available product)
- Economic feasibility

NG Resource

The nontraditional NG resource of the Williston Basin is located in northwestern North Dakota, west of large coal-based electrical generation. Figure 30 shows the flared NG in relation to existing coal-fired generation as well as electrical transmission infrastructure. Figure 31 shows the same flared NG in relation to electrical distribution cooperative service territory.

Power Demand/Market

The demand for power in the Williston Basin since the onset of the current oil "boom" has grown rapidly. Two electric utilities serve the Williston Basin area: Montana–Dakota Utilities Co. (MDU) generates electricity for the major municipalities and Basin Electric Power Cooperative (BEPC) provides power, through its member cooperatives, for the rural areas. Based on information provided by MDU and BEPC, electricity consumption is increasing significantly.

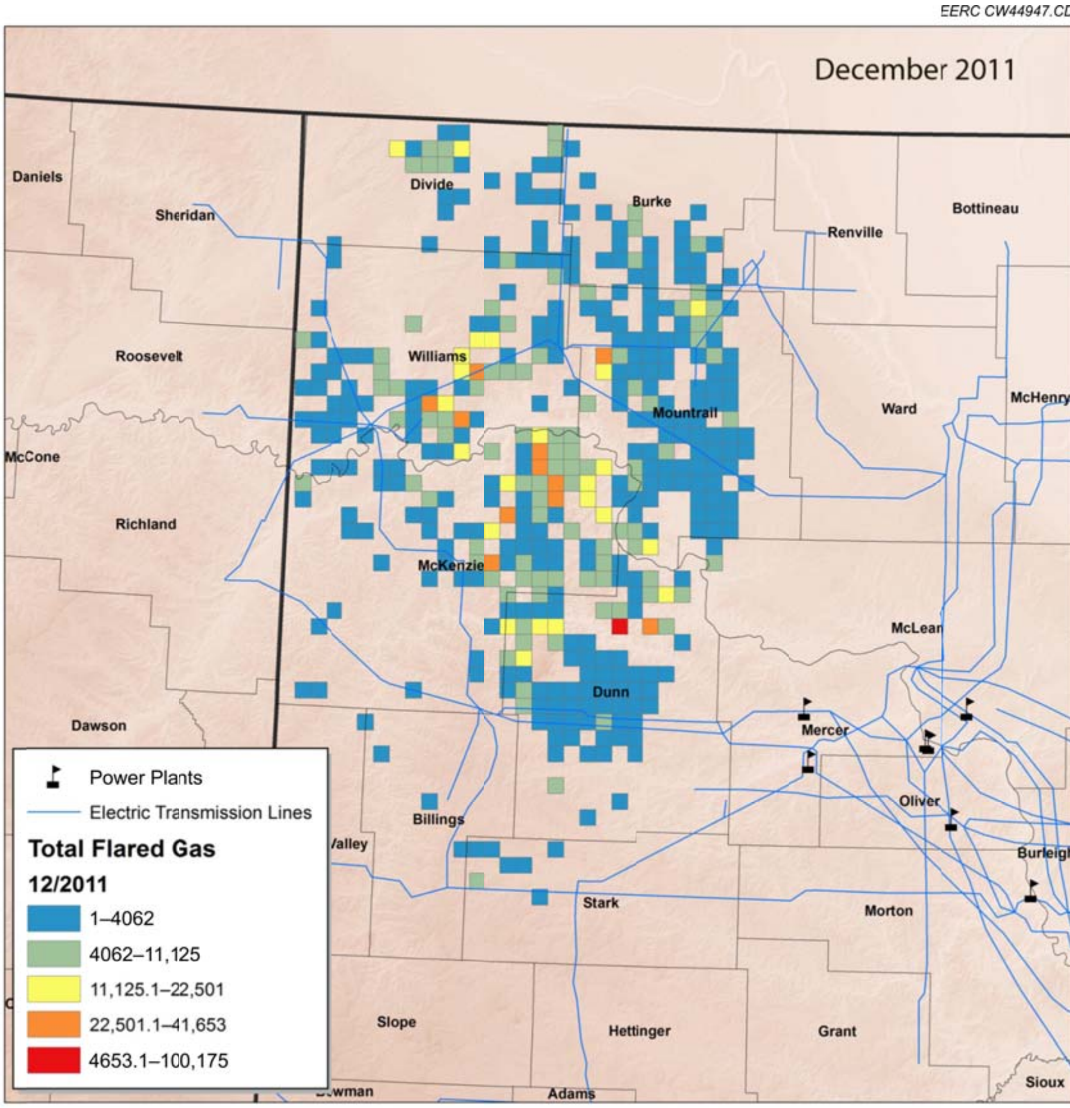


Figure 30. Flared NG and existing electrical transmission.

As an example, BEPC is forecasting the load increase from 600 MW in 2010 to over 1900 MW by 2025 in the oil-producing area of western North Dakota and eastern Montana. Although no load forecast was available from MDU, for the five major towns in the Williston Basin (Williston, Tioga, Stanley, Watford City, and Dickinson), similar load increases are expected as exhibited by a 13% increase in electrical consumption from 2010 to 2011.

Some detailed work related to load forecasting has been performed. In 2007, Pace Global Energy Services prepared a report for BEPC entitled "Williston Basin Oil Development Power Load Forecast Study" (Pace Global Energy Services, 2007). In this report, based on input from oil industry representatives, Pace provided BEPC with a multiple-scenario forecast of future load in the Williston Basin portion of its service territory. Highlights from the Pace report along with the addition of EERC comments are summarized in Table 28.

EERC CW44942.CDR

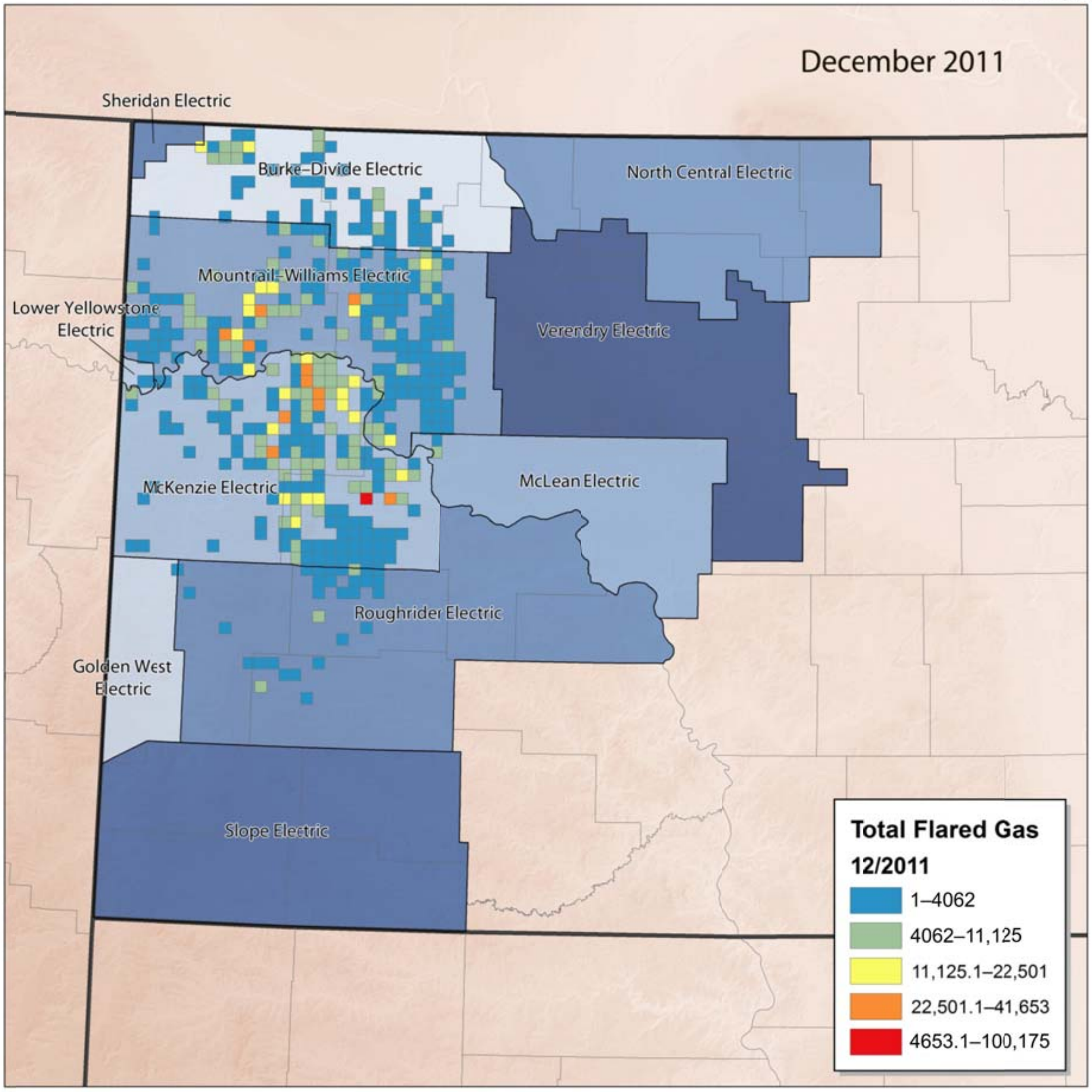


Figure 31. Flared NG and electrical distribution cooperative service territory.

The Pace report contained information about the current state of oil and gas development and electrical load in the Williston Basin as well as three scenarios of future development and load growth. Based on the publication date, it was assumed that the information presented was based on 2006 data.

In addition to meeting this growing demand, utilities are also faced with ensuring grid reliability. Grid reliability, although not on the minds of most customers until an outage occurs, is vitally important, as evidenced by the April 2011 blizzard that left an estimated 30,000 people without power and shut down the production of oil, costing the industry more than 350,000 bbl of production.

Table 28. Pace Report Highlights and EERC Comments

Oil and Gas Development in the Williston Basin

Pace Findings (based on 2006 information)	EERC Comments (based on 2011 information)
Rapid large-scale development of the Williston Basin will be constrained by the availability of rigs, labor, and service.	This statement was valid in 2011, although development from 2007 to 2011 was quite rapid as defined by the Pace "high" scenario, even with constrained availability of rigs, labor, and service.
Lack of availability of electric power will not affect drilling plans, as all wells produce sufficient quantities of NG to be self-sustaining.	The EERC does not have sufficient information to concur with or refute this point.
Pump jacks can be driven by electric motor or a gas-fired engine, but industry strongly prefers electric.	This statement still holds true.
A typical Bakken well has a life of 25–30 years and will produce 300,000 bbl over that life (although oil production forecasts do not drive power load forecast).	Although the life of a typical Bakken well may be 25–30 years, the lifetime production is very likely higher than 300,000 bbl.
Standard spacing for a Bakken well is 1280 acres.	This statement still holds true, although other spacing units are being defined (both smaller and larger).

Power Load Forecast

Pace Findings (based on 2006 information)	EERC Comments (based on 2011 information)
Power load is derived from the following primary uses: • Electric motors driving pump jacks • Electrically driven field gas gathering • Compressor stations and gas-processing plants • Enhanced oil recovery (EOR)-related pumping loads • Booster pump stations on crude pipelines	The EERC concurs with this assumption and will use the same for its calculations.
Power load requirements in the Williston Basin are expected to increase over the next 20 years (2027).	This statement still holds true.
Power requirements in the Williston Basin will be long term as wells typically produce for 25 to 30 years.	This statement still holds true.
Pace used a conversion factor of 0.746 to convert horsepower to electrical demand (kW)	The EERC concurs with this assumption and will use the same for its calculations.

Continued . . .

Table 28. Pace Report Highlights and EERC Comments (continued)

Power Load Forecast

Pace Findings (based on 2006 information)	EERC Comments (based on 2011 information)
Demand requirements assume a load factor of 80%–100% depending on scenario.	The EERC concurs with this assumption and will use the same for its calculations.
Future unplanned EOR and gas-gathering, compression, and processing loads represent a huge potential power requirement that was not accounted for in the Pace load forecast.	This statement may explain why even the Pace “high” scenario underestimated the load growth from 2007 to 2011.

Enhance Oil Recovery

Pace Findings (based on 2006 information)	EERC Comments (based on 2011 information)
Oil produced from EOR activity accounts for approximately 60% of the oil produced in North Dakota.	Although our data do not address EOR specifically, this situation has certainly changed drastically. In 2006, oil production from the Bakken Formation accounted for roughly 6% of the annual total from 300 wells. By 2010, that number was up to 76% from more than 2100 wells.

Gas Gathering and Processing

Pace Findings (based on 2006 information)	EERC Comments (based on 2011 information)
General consensus amongst industry is that additional gas gathering and processing are required in the Williston Basin.	Although additional gas-gathering and process infrastructure has been built, this statement still holds true.

Oil Price Forecast

Pace Findings (based on 2006 information)	EERC Comments (based on 2011 information)
Industry currently believes $40–$45/bbl WBS is the minimum price required for Williston Basin wells to be economical.	The EERC does not have sufficient information to concur with or refute this point.
Over the next 20 years, the West Texas Intermediate (WTI) forecast price averages $56/bbl and never drops below $50/bbl, thus supporting continued development of the Williston Basin assuming operational costs do not increase.	This statement has held true, although the actual WTI price has tracked more closely with the Pace “High 95%” than the “Expected” scenario from 2007 to 2011.

Applicable Technologies

In 2003, NREL and Gas Research Institute (GRI) prepared a very thorough technical report summarizing the gas-fired technologies suitable for distributed electrical generation (Goldstein et al., 2003). A review of that document verifies that several platforms are suitable for distributed power generation using some form of gas. The technologies discussed in the NREL–GRI report are summarized in Table 29.

Table 29. Summary of Technologies Analyzed in the NREL–GRI Report

	Reciprocating Engine	Gas Turbine	Steam Turbine	Microturbine	Fuel Cell
Technology Maturity	Mature	Mature	Mature	Immature	Immature
Size – Single Unit, MW	0.01–5	0.5–50	0.05–50	0.03–0.25	0.005–2
Electric Efficiency, HHV[1]	30%–37%	22%–37%	5%–15%	23%–26%	30%–46%
Total CHP[2] Efficiency, HHV	69%–78%	65%–72%	80%	61%–67%	65%–72%
Power-Only Installed Cost, $/kW	700–1000	600–1400	300–900	1500–2300	2800–4700
CHP Installed Cost, $/kW	900–1400	700–1900	300–900	1700–2600	3200–5500
O&M Cost, $/kWh	0.008–0.018	0.004–0.01	<0.004	0.013–0.02	0.02–0.04
Availability	>96%	>98%	Near 100%	95%	90%
Equipment Life, years	20	20	>25	10	10
Fuel Pressure, psi	1–65	100–500	NA	55–90	0.5–45
NO_x Emissions, lb/MWh	0.2–6.0	0.8–2.4		0.5–1.25	<0.1

[1] Higher heating value.
[2] Combined heat and power.

An initial review of the characteristics of each technology (presented in Table 30) eliminated some options from further discussion. Borne out of this review, three technologies warranted further consideration: reciprocating engine, gas turbine, and microturbine.

Reciprocating Engine

The reciprocating, or internal combustion, engine is categorized as either spark-ignited or compression-ignited. Spark-ignited engines are typically fueled with lean NG but can also be fueled by gasoline, NG, hydrogen, or syngas. Compression-ignited engines are typically fueled by diesel fuel or other heavy oils. The output shaft of the engine is connected to an electrical generator to produce electricity. Compression–ignition engines can also be set up to operate on a bifuel configuration utilizing both diesel and NG.

Table 30. Summary of Technology Characteristics Review

Technology	Reasons for Further Consideration	Reasons Against Further Consideration
Reciprocating Engine	• Technology maturity • Scale • Electric efficiency • Cost • Equipment life • Fuel pressure • Fuel flexibility (requires specific engine setup) • NO_x emissions (rich gas may pose challenge)	
Gas Turbine	• Technology maturity • Scale • Electric efficiency • Cost • Equipment life • Fuel flexibility (rich gas may pose challenge) • NO_x emissions (rich gas may pose challenge)	
Steam Turbine	• Technology maturity • Scale • Cost • Equipment life • Fuel flexibility • NO_x emissions (combustion method dependant)	• Electric efficiency
Microturbine	• Electric efficiency • Fuel pressure • Fuel flexibility • NO_x emissions	
Fuel Cell	• Electric efficiency • Fuel pressure • NO_x emissions	• Technology maturity • Scale • Cost • Equipment life • Fuel flexibility (hydrogen fuel only)

Gas Turbine

Gas turbines can be used to generate electricity from a variety of gas feedstocks, including gasification syngas, NG, and others. Gas turbines can be configured as simple cycle or combined-cycle systems. Simple cycle systems involve the use of a turbine fueled by gas to compress air. As the compressed air enters an expansion turbine, it turns an electrical generator. Combined-cycle systems also incorporate subsystems that recover exhaust heat and convert it to electricity.

Steam Turbine

Steam turbines, as the name implies, use a fuel to create steam in a boiler. The steam is delivered to a steam generator producing electricity. Steam turbines are unique in that the fuel-burning/steam-generating process is separate from the electrical generating process allowing unmatched fuel flexibility.

Microturbine

Microturbines are basically smaller versions of gas turbines consisting of the following main components:

- Compressor
- Combustor
- Turbine
- Generator
- Recuperator
- Waste heat recovery system

Microturbines are typically classified by their physical component configuration—single-shaft or two-shaft, simple-cycle or recuperated, intercooled, and reheat—typically operate on traditional gases such as NG. The microturbine can also be operated on other gases including gasifier syngas. EERC research has demonstrated that microturbines can successfully be operated on off-spec, high-Btu, and/or low-Btu gases such as oil field sour gas.

Fuel Cell

There are several types of fuel cells, each of which creates direct current electricity from electrochemical reactions. Although each type of fuel cell functions basically the same, they convert hydrogen to electricity in much different ways and are best suited for different applications. Simply put, hydrogen fuel, air or oxygen, and sometimes carbon dioxide (depending on the fuel cell) are delivered to the fuel cell, producing electricity and other by-products such as water, waste heat, and excess gas (again, depending on the fuel cell).

Initial Evaluation

Given the focus on nontraditional NG (i.e., rich gas with little processing) and a desired scale of 0.5 to 10 MW, three technology platforms were considered to be most technically and economically viable and are discussed further, reciprocating engines, gas turbines (including microturbines), and steam turbines. Each of these technologies has specific advantages, and depending on the application, a single technology may be best suited to meet the needs of the application. A summary of power generation scenarios is presented in Table 31.

When evaluating power generation scenarios, the projects were characterized into two distinct categories based on the primary use of the electricity:

Table 31. Summary of Power Generation Scenarios

Description	Example	Power on Required	Applicable Technology	General Logistics
Grid Support: generator running on flare gas, producing electricity put on the grid.		1–10 MW	– Reciprocating – Gas turbine – Steam turbine	– Flare gas to system – Electrical to grid
Local Power – Small: generator running on flare gas, producing electricity for local consumption.	– Pump jack – Cellular tower	0.2–0.5 MW	– Reciprocating – Gas turbine – Steam turbine – Microturbine – Fuel cell	– Flare gas to system – Electrical to local load – Excess electricity to grid
Local Power – Midsize: generator running on flare gas, producing electricity for local consumption.	– Mancamp – Clustered wells – Drilling rig	0.5–1 MW	– Reciprocating – Gas turbine – Steam turbine – Microturbine	– Flare gas to system – Electrical to local load – Excess electricity to grid
Local Power – Large: generator running on flare gas, producing electricity for local consumption.	– Industrial plant	1–10 MW	– Reciprocating – Gas turbine – Steam turbine	– Flare gas to system – Electrical to local load – Excess electricity to grid

1) Grid support – power generation for direct delivery onto the electrical grid.

2) Local power – power generation for local use with excess generation (if any) sent to the electrical grid.

A grid support project, although not without logistical issues, is straightforward in design, whereas a local power project tends to be more complex because of the introduction of significantly more design variables. The evaluation of power generation scenarios assumes that adequate electrical infrastructure exists to accommodate the additional electricity these systems generate (if delivered to the electrical grid).

Grid Support

A grid support project is fairly simple by description. Wellhead gas (with limited cleanup) is piped to the electrical generator. The generator burns the gas and produces electricity, which is put on the electrical grid for distribution by the local utility to its customers.

The scale of these projects tends to be driven by capital costs (and cost recovery), and often there is an economy of scale that typically results in larger generators being more economically feasible. This larger scale, in turn, usually favors reciprocating engines, gas turbines, and steam turbines and precludes technologies such as microturbines and fuel cells.

Local Power

A local power project is similarly described as wellhead gas (with limited cleanup) which is piped to the electrical generator, and the generator burns the gas and produces electricity. But in this case, the electricity is first used to power local consumption, with any excess electricity put on the electrical grid for distribution by the local utility to its customers.

Although capital costs are still vitally important, the scale of the local power project is equally driven by matching the local electrical load with generation. These projects can range widely in scale, depending on the goal of the project (i.e., satisfy only local load, satisfy local load with minimal excess generation, or satisfy local load with significant excess generation). For this reason, most power generation technologies may be appropriate, depending on the project.

Detailed Evaluation

As indicated in earlier sections, Bakken associated gas is high in NGLs, resulting in a gas with very high Btu values (approximately 1400 Btu/cf). Since the NGLs make up a majority of the economic value of the rich gas, removal of at least a portion of the NGLs from the rich gas is beneficial to the economics of the project and may be advantageous to (or required by) the operation of the electrical generator. All scenarios were evaluated with the following assumptions:

- Rich gas flow rate from the wellhead (average of all Bakken wells): 300 Mcf/day
- Rich gas flow rate from the wellhead (local power scenarios): 600 Mcf/day
- Rich gas flow rate from the wellhead (grid support scenarios): 1000–1800 Mcf/day
- Rich gas Btu content: 1400 Btu/cf
- NGL removal system used
- Volume of NGLs existing in rich gas: 10–12 gallons/Mcf
- Volume of NGLs removed from rich gas: 3–5 gallons/Mcf (1000 Mcf/day would result in 3000–5000 gallons of NGLs/day)
- NGLs stored in 200-psi vessels at the location and periodically trucked to an off-loading facility
- NGL price (value) at the off-loading facility: $1.00/gallon
- Lean gas flow rate from NGL removal system: 850 Mcf/day
- Lean gas Btu content: 1210–1250 Btu/cf

- Lean gas price (value) consumed by electrical generator: $2.00/Mcf

- Price (value) of electricity generated and delivered to the grid: $0.05/kWh

- Price (value) of electricity generated and consumed on-site: $0.09/kWh

In addition to the assumptions listed above, the gas composition of the lean gas (1210–1250 Btu/cf) was assumed to be as represented in Table 32.

Table 32. Assumed Lean Gas Composition

Component	mol%
H_2O	0.01
N_2	6.10
CO_2	0.62
H_2S	0.00
C1	66.33
C2	19.42
C3	6.62
C4	0.84
C5	0.06
C6	0.00
C7	0.00
C8	0.00
C9	0.00
C10–C11	0.00
C12–C15	0.00

Two power generation scenarios were evaluated for each category. In the grid support category, a reciprocating engine and a gas turbine scenario were evaluated, and in the local power category, the authors evaluated both a reciprocating engine and a microturbine.

For each of the scenarios, capital expenditures for land acquisition and the NGL removal and storage system were deemed common for all scenarios and, therefore, described separately.

Land Acquisition

Analysis of the power generation scenarios assumed that the placement of the power generation system and its related components would not require the purchase or rental of additional land area.

NGL Removal and Storage

The removal of NGLs from the rich gas, although not necessarily required, greatly increases the economics of a power generation project, improves the performance of the genset, and reduces the loss of resource (when flaring is necessary).

Based on modeling done as part of this study, the EERC concluded that removing the NGLs (specifically butane and heavier constituents and a portion of propane) can be accomplished with chilling and JT cooling operated at −20°F and 200–1000 psi. Once the NGLs have been separated and stabilized, they are pumped to on-site storage tanks.

At an estimated NGL removal rate of 4 gallons/Mcf (from 1000 Mcf/day of rich gas), the daily production of NGLs would be approximately 4000 gallons of NGLs per day. Based on this NGL production number and a desire to have 2 weeks worth of storage capacity, the required storage capacity would be approximately 56,000 gallons (1300 bbl). NGLs would need to be stored on-site at a minimum pressure of 200 psi to maintain NGLs in the liquid phase.

Although not widely available in a small, modular configuration, based on discussions with industry representatives, the estimated capital cost for the NGL removal and storage system is $2,500,000. This capital cost includes the necessary compression to take the rich gas from the heater/treater at 35 psi up to 200–1000 psi delivered to the NGL removal system as well as the cost for four 400-bbl NGL storage tanks.

The power generation scenarios analyzed in this study employ a NGL removal system since the authors consider it to add significant value. Since the capital cost for this system is presented separately, it is simple for the reader to remove it from the capital equation if deemed unnecessary.

It should be noted that in each scenario, the assumed flow of associated gas from the wellhead was sized to match the fuel consumption of the respective electrical generator in the scenario. Table 33 summarizes the assumed wellhead gas flow for each scenario, and Figure 32 shows a block flow diagram of the NGL removal system as an example.

Table 33. Summary of Wellhead Gas Flow and Product Volume Assumptions

Scenario	Rich Gas Flow, Mcf/day	NGLs Produced, gallons/day	Lean Gas Produced, Mcf/day
Grid Support – Reciprocating Engine	1000	4000	850
Grid Support – Gas Turbine	1800	7200	1530
Local Power – Reciprocating Engine	600	2400	510
Local Power – Microturbine	600	2400	510

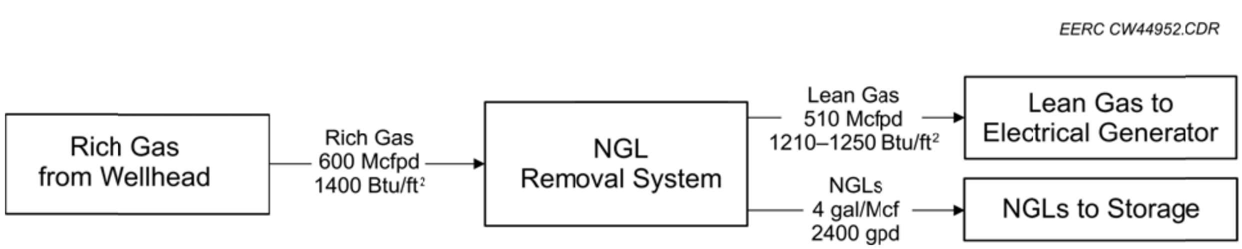


Figure 32. NGL removal system block flow diagram.

Grid Support – Reciprocating Engine Scenario

This scenario can be basically described as a reciprocating engine genset burning lean gas and producing electricity for bulk delivery to the electrical grid. A NGL removal system is utilized to separate NGLs from the rich gas stream prior to the electrical generator. The NGLs from the NGL removal system are pumped to on-site storage vessels. All electricity from the generator is delivered to the electrical grid. A simplified process flow diagram is provided as Figure 33.

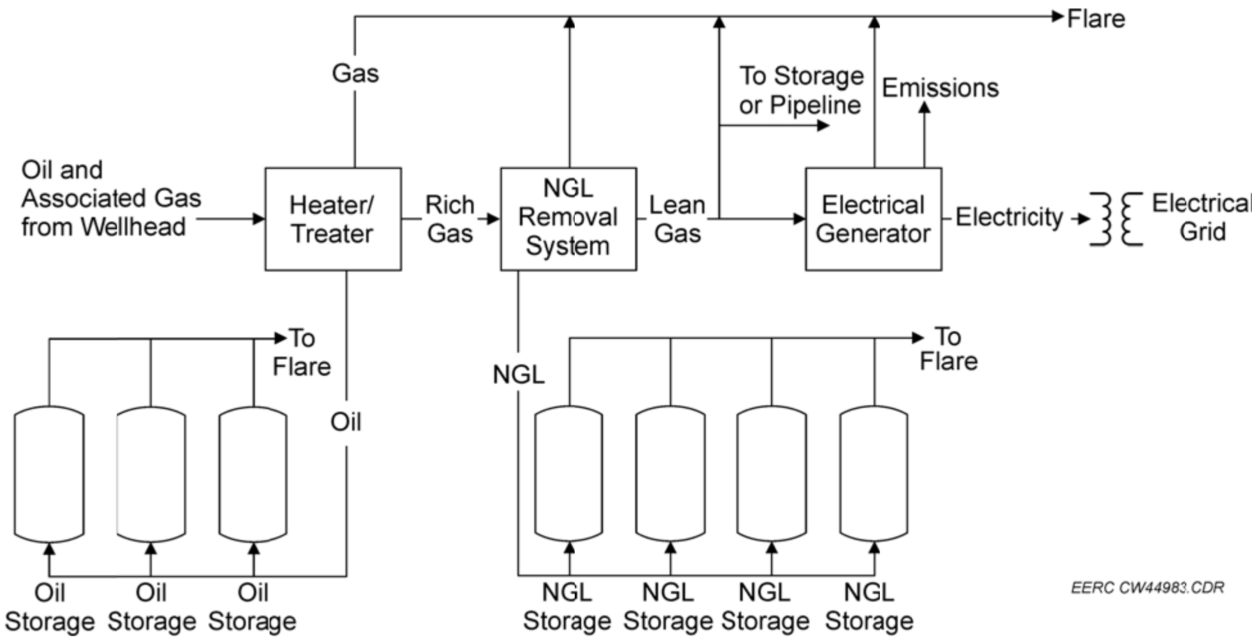


Figure 33. Process flow diagram, grid support – reciprocating engine scenario.

The scale of the system in this scenario is not dictated by any particular electrical load but rather, is a function of project economics and the desired level of grid support in that area (both in relation to the electrical load in the area and the ability of the grid to handle delivery of the electricity). The system scale for this application and technology would most typically range from 1 to 10 MW, and for this study a scale of approximately 5 MW was chosen for analysis.

Quotations were solicited from manufacturers to establish the capital and O&M costs for the reciprocating engine genset. Based on information provided by the equipment vendors, the capital cost for a reciprocating engine genset consisting of three 1700-kW generators (5100-kW nameplate capacity) is estimated to be approximately $4,000,000 ($800 per kW). Annual O&M cost was assumed to be 10% of the capital cost, or $400,000. The total costs for this scenario are summarized in Table 34.

Table 34. Total Cost Summary, Grid Support – Reciprocating Engine Scenario

	Cost
Capital Costs	
NGL Removal and Storage System	$2,500,000
Electrical Generator System	$4,000,000
Balance of Plant	$1,000,000
Total Capital Cost	**$7,500,000**
Annual O&M Costs	
NGL System	$250,000
Electrical Generator System	$400,000
Total O&M Cost	**$650,000**

Using the assumptions presented at the beginning of the Detailed Evaluation section, the process and product description can be described as follows. 1000 Mcf/day of associated wellhead gas from the heater/treater would be processed by the NGL removal system into 850 Mcf/day of lean gas and 4000 gallons of NGLs. The NGLs are pumped to on-site storage and delivered to market via truck. The lean gas is supplied to the electrical generation system which would consume all 850 Mcf/day and produce 114,000 kWh of electricity per day that would be transmitted to the electrical grid. The revenue streams for these products are summarized in Table 35.

Table 35. Summary of Product Revenues, Grid Support – Reciprocating Engine Scenario

Product	Quantity	Assumed Value	Daily Revenue	Annual Revenue[1]
NGLs	4000 gpd	$1.00/gal	$4000	$1,168,000
Electricity	114,000 kWh/day	$0.05/kWh	$5700	$1,664,400
Total			$9700	$2,832,400

[1] Assumes 80% annual system availability.

Grid Support – Gas Turbine Scenario

As in the previous scenario, the grid support – gas turbine scenario involves supplying rich gas from the wellhead to a NGL separation system. NGLs are stored on-site, and lean gas is fed to a gas turbine. Electricity produced from the gas turbine is delivered to the electrical grid. As shown in Figure 34, the process flow diagram is the same as the reciprocating engine scenario.

Again targeting a scale of approximately 5 MW for this scenario, quotations were solicited from vendors. A budgetary cost estimate for a gas turbine genset comprising three 2000-kW generators was $6,400,000 ($1067/kW). Again, the O&M cost was assumed to be 10% of the capital cost, or $640,000 annually. The total costs for this scenario are summarized in Table 36.

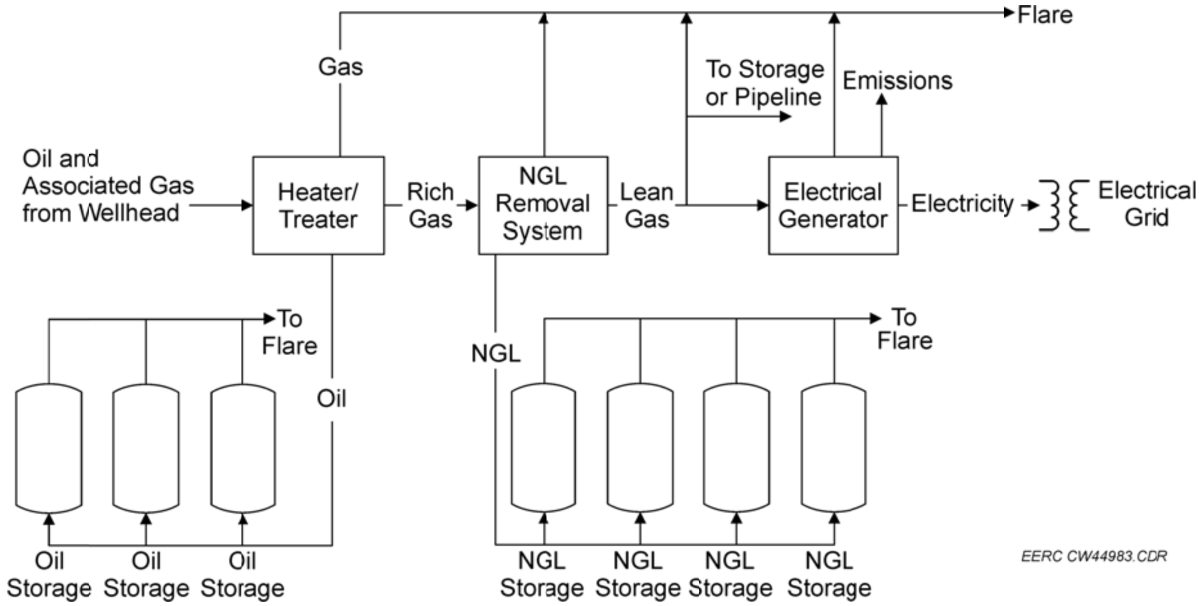


Figure 34. Process flow diagram, grid support – gas turbine scenario.

Table 36. Total Cost Summary, Grid Support – Gas Turbine Scenario

	Cost
Capital Costs	
NGL Removal and Storage System	$2,500,000
Electrical Generator System	$6,400,000
Balance of Plant	$1,000,000
Total Capital Cost	**$9,900,000**
Annual O&M Costs	
NGL System	$250,000
Electrical Generator System	$640,000
Total O&M Cost	**$890,000**

Using the assumptions presented at the beginning of the Detailed Evaluation section, the process and product description can be described as follows. 1800 Mcf/day of associated wellhead gas from the heater/treater would be processed by the NGL removal system into 1530 Mcf/day of lean gas and 7200 gallons of NGLs. The NGLs are pumped to on-site storage and delivered to market via truck. The lean gas is supplied to the electrical generation system which would consume the entire 1530 Mcf/day and produce 140,400 kWh of electricity per day that would be transmitted to the electrical grid. The revenue streams for these products are summarized in Table 37.

Table 37. Summary of Product Revenues, Grid Support – Gas Turbine Scenario

Product	Quantity	Assumed Value	Daily Revenue	Annual Revenue[1]
NGLs	7200 gpd	$1.00/gal	$7200	$2,102,400
Electricity	140,400 kWh/day	$0.05/kWh	$7020	$2,049,840
Total			$14,220	$4,152,240

[1] Assumes 80% annual system availability.

Local Power – Reciprocating Engine Scenario

The local power – reciprocating engine scenario employs the same NGL removal system prior to introduction of the rich gas to the generator. Electricity generated is first used to satisfy on-site demand, with the excess electricity fed to the electrical grid. The scale for the local power – reciprocating engine scenario was targeted to be approximately 1 MW. Figure 35 depicts the process flow diagram for the local power – reciprocating engine scenario.

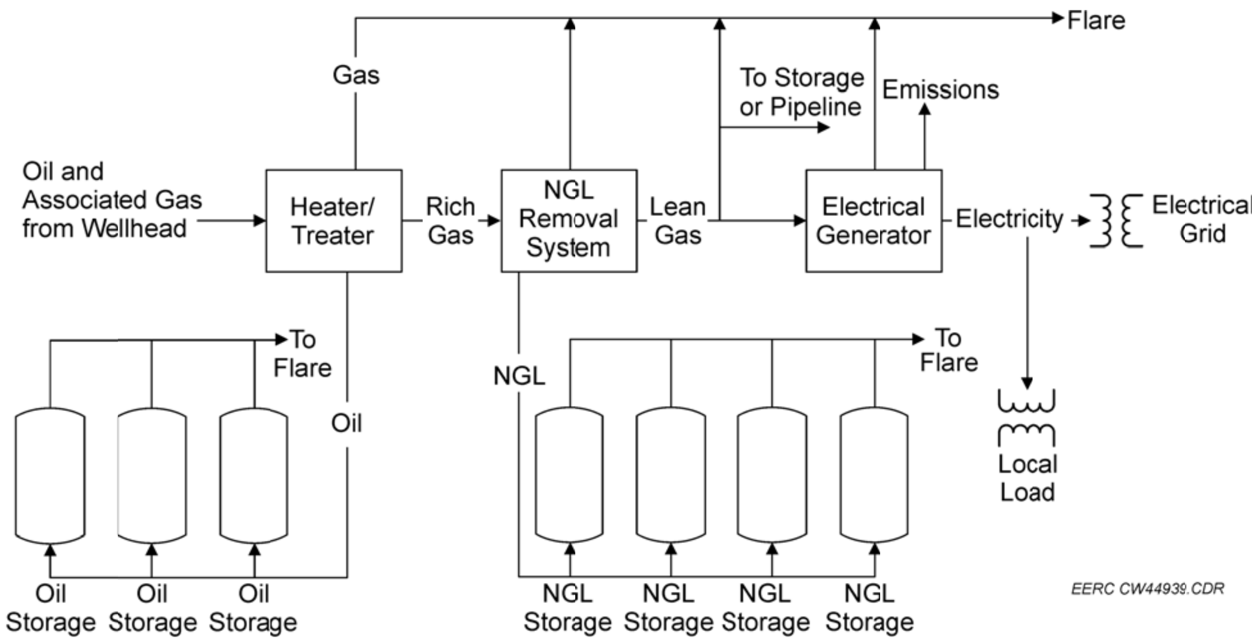


Figure 35. Process flow diagram, local power – reciprocating engine scenario.

A quote was solicited for a NG-fired genset of approximately 300 kW in size. The vendor provided a quote for a single 250-kW NG reciprocating engine genset. The capital cost for the genset is approximately $200,000, and the annual O&M cost was assumed to be 10% of the capital cost. The costs for this scenario are summarized in Table 38.

Table 38. Total Cost Summary, Local Power – Reciprocating Engine Scenario

	Cost
Capital Costs	
NGL Removal and Storage System	$2,500,000
Electrical Generator System	$200,000
Balance of Plant	$500,000
Total Capital Cost	**$3,200,000**
Annual O&M Costs	
NGL System	$250,000
Electrical Generator System	$20,000
Total O&M Cost	**$270,000**

Using the assumptions presented at the beginning of the Detailed Evaluation section, the process and product description can be described as follows. 600 Mcf/day of associated wellhead gas from the heater/treater would be processed by the NGL removal system into 510 Mcf/day of lean gas and 2400 gallons of NGLs. The NGLs are pumped to on-site storage and delivered to market via truck. The lean gas is supplied to the electrical generation system which consumes 101 Mcf/day and produces 6000 kWh of electricity that serves on-site electrical load. The remaining lean gas (approximately 499 Mcf/day) is either stored on-site for truck transport to the pipeline or pumped directly into a NG-gathering system for delivery to a gas-processing plant. For this example, we will assume excess gas is sold. The revenue streams for these products are summarized in Table 39.

Table 39. Summary of Product Revenues, Local Power – Reciprocating Engine Scenario

Product	Quantity	Assumed Value	Daily Revenue	Annual Revenue[1]
NGLs	2400 gpd	$1.00/gal	$2400	$700,800
Electricity	6000 kWh/day	$0.09/kWh	$540	$157,680
Lean gas	499 Mcf/day	$2.00/Mcf	$998	$291,416
Total			$3938	$1,149,896

[1] Assumes 80% annual system availability.

Local Power – Microturbine Scenario

This scenario involved the removal of NGLs prior to delivery of gas to the microturbine and the use of generated electricity to satisfy local electrical demand, with the excess electricity delivered to the grid. The scale of this scenario is smaller than other scenarios to provide a range of generation scales. For this reason, two scenarios were examined at a scale close to 200 kW. Figure 36 shows the process flow diagram of the local power – microturbine scenario.

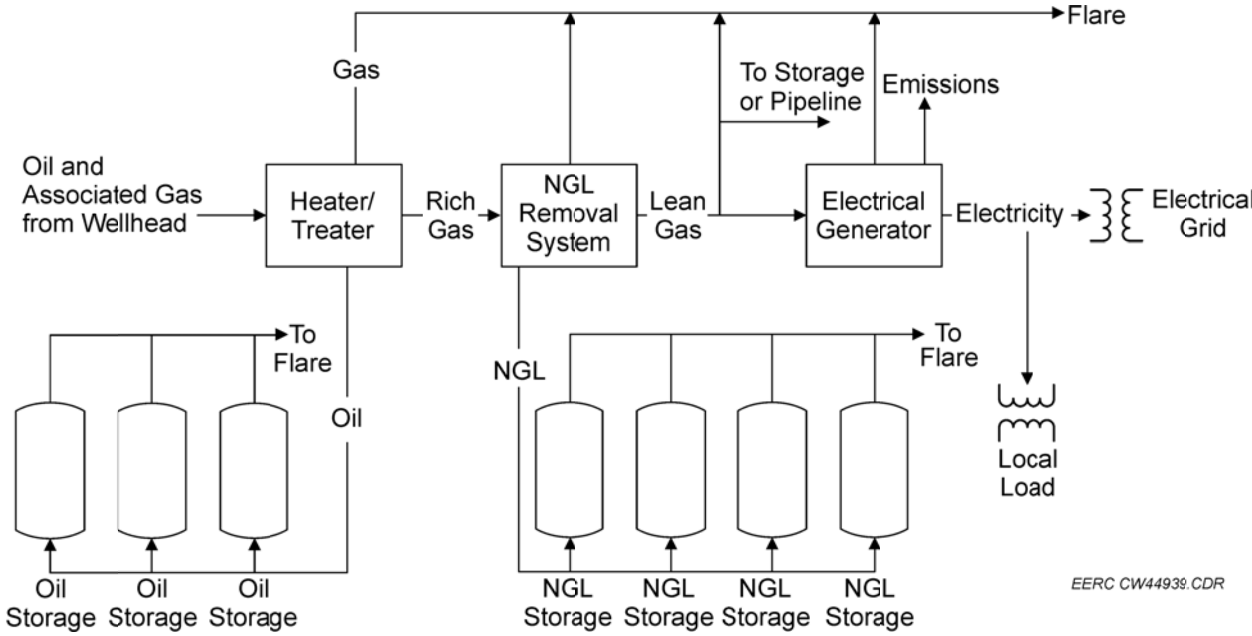


Figure 36. Process flow diagram, local power – microturbine scenario.

To accurately size a system, the vendor used EERC-provided conditions including a 2250-feet-above-sea-level elevation and a maximum ambient temperature of 100°F. This would represent the worst-case scenario as far as electrical production environment and result in a derated output of between 20% and 25%. The two systems offered by the vendor were both configured as multiple microturbines coupled together in a single package and resulted in package systems that were approximately 200 kW in scale. Table 40 summarizes the two packages offered by the vendor.

Table 40. Flow Diagram, Local Power – Microturbine Scenario

Description	Nominal Power Rating	Actual Power Rating	Derate	Gas Consumed	Electricity Generated
Four 65-kW Microturbines	260 kW	195 kW	25%	49 Mcf/day	4683 kWh/day
Two 200-kW Microturbines	400 kW	316 kW	20%	68 Mcf/day	7595 kWh/day

In selecting either package, the NGL removal system is likely to be much larger in processing capacity than the electrical generation system. Generally, the NGL removal system will be most economical only at the higher-gas-producing wells. As shown in Table 40, both small-scale microturbines consume less than 100 Mcf/day. This means that the project either flares excess lean gas or is designed to store the excess gas for sale to the pipeline. In the examples that follow, it is assumed that the excess lean gas is sold.

In both cases, the vendor offers a factory protection plan (FPP) that covers all scheduled and unscheduled maintenance of the system as well as parts, including an overhaul or turbine replacement at 40,000 hours of operation. The FPP "locks in" the annual O&M cost of the system, and in both scenarios presented below, it is assumed that the FPP is purchased.

For the purposes of this report the authors chose to analyze the smaller package (four 65-kW microturbines) as it more closely matched the 200-kW scale and provided more flexibility should a single turbine need to be taken off line for maintenance or some other reason.

Four 65-kW Microturbine System

This system consists of four 65-kW Capstone microturbines combined in a single package nominally rated at 260 kW of electrical output. Under the conditions discussed above, the system would be derated and provide approximately 195 kW of power (or 25% derate). Table 41 provides a summary of the capital and O&M costs using the costs discussed in this section and costs presented in the NGL Removal and Storage section.

Table 41. Total Cost Summary, Local Power – Microturbine Scenario (Four 65-kW)

	Cost
Capital Costs	
NGL Removal and Storage System	$2,500,000
Electrical Generator System	$383,200
Balance of Plant	$500,000
Total Capital Cost	**$3,383,200**
Annual O&M Costs	
NGL System	$250,000
Microturbine FPP	$33,640
Total O&M Cost	**$283,640**

Using the assumptions presented at the beginning of the Detailed Evaluation section, the process and product description can be described as follows. 600 Mcf/day of associated wellhead gas from the heater/treater would be processed by the NGL removal system into 510 Mcf/day of lean gas and 2400 gallons of NGLs. The NGLs are pumped to on-site storage and delivered to market via truck. The lean gas is supplied to the electrical generation system which consumes 49 Mcf per day and produces 4683 kWh of electricity that serves on-site electrical load. The remaining lean gas (approximately 461 Mcf/day) is either stored on-site for truck transport to the pipeline or pumped directly into a NG-gathering system for delivery to a gas-processing plant. The revenue streams for these products are summarized in Table 42.

Drilling Rig Power

The use of wellhead gas as a fuel for drilling operations derives advantages from both CNG and power production scenarios described previously. In reciprocating diesel engines, rich

Table 42. Summary of Product Revenues, Local Power – Microturbine Scenario (Four 65-kW)

Product	Quantity	Assumed Value	Daily Revenue	Annual Revenue[1]
NGLs	2400 gpd	$1.00/gal	$2400	$700,800
Electricity	4683 kWh/day	$0.09/kWh	$421	$122,932
Lean gas	461 Mcf/day	$2.00/Mcf	$922	$269,224
Total			**$3743**	**$1,092,956**

[1] Assumes 80% annual system availability.

wellhead gas can be combusted with little more than dewatering as pretreatment. Further, since the fuel displaced is high-priced diesel fuel, the economics are favorable over other lower-priced power production applications like large-scale coal or natural gas-based electrical production.

As a separate task under this project, the EERC is working with Continental Resources, ECO-AFS, Altronics, and Butler Caterpillar to conduct a detailed study and field demonstration of the GTI Bi-Fuel System®. Within that task, the EERC conducted a series of tests at the EERC using a simulated Bakken gas designed to test the operational limits of fuel quality and diesel fuel replacement while monitoring engine performance and emissions. Additionally, a field demonstration of the Bi-Fuel System will be completed in the summer of 2012 during which engine performance, emissions, and fuel savings will be monitored for the duration of a two-well batch drilling operation. The field demonstration will provide researchers and project partners detailed information on how the system performs in real well drilling operations and validate fuel savings achievable over extended operation.

ECO-AFS has recently installed several Bi-Fuel Systems on rigs in the Williston Basin. Early data suggest that diesel fuel savings of approximately $1 to $1.5 million can be achieved annually. Under typical conditions, operators can expect to achieve diesel replacement of 40%–60% at optimal engine loads of 40%–50%.

Because the Bi-Fuel System is an aftermarket addition providing natural gas to the air intake, engine performance is not altered in diesel-only operation. If the natural gas supply is interrupted or unavailable at a location, the engines can continue to operate on diesel fuel without requiring any alterations. The control system of the Bi-Fuel System also provides a number of safety protocols that simply stop gas flow if any engine performance parameters exceed manufacturer-recommended limits. The Bi-Fuel System controls continue to monitor engine performance, and when engine operational parameters return to acceptable ranges, gas can again be supplied to the engines.

Total installed capital cost for the Bi-Fuel System ranges from $200,000 to $300,000. Once hardware is installed, additional costs will be incurred to bring wellhead gas to the engine building. These costs can vary greatly depending on distance to the nearest gas source and gas lease terms. These costs have not been included in this assessment.

Evaluation Summary

A wide variety of power generation technologies exist that can utilize rich gas of varying quality to produce electricity. Power generation technologies also match the assortment of wellhead gas flow rates and can be constructed for mobility if needed.

For these reasons, power generation as an end use technology for NG, whether it be flared associated gas, gathered but untreated gas, or processed NG, is a strong candidate technology for consideration.

From an economic perspective, the hypothetical power generation scenarios presented in this section and summarized in Table 43 provide a preliminary technical and economic evaluation that should afford an initial indication of project feasibility. Many assumptions were made and the reader should carefully consider the relevance of these assumptions to their specific circumstances.

Table 43. Summary of Power Generation Scenarios

Scenario	Capital Cost	Annual O&M Cost	Annual Revenue[1]
Grid Support – Reciprocating Engine	$7,500,000	$650,000	$2,832,400
Grid Support – Gas Turbine	$9,900,000	$890,000	$4,152,240
Local Power – Reciprocating Engine	$3,200,000	$270,000	$1,149,896
Local Power – Microturbine	$3,383,200	$283,640	$1,092,956

[1] Assumes 80% annual system availability.

Based on cost and revenue assumptions provided in the previous sections, all scenarios provided a simple payback of 3 years or less. It should be noted that since the contractual arrangements vary widely regarding "ownership" of the rich wellhead gas, no cost was assigned to obtaining the wellhead gas in the scenarios presented. Readers should take into account this input cost based on their specific situation as it will impact the overall economics significantly in certain cases.

In addition to rig power, discussed in the previous section, there are a number of other potential natural gas uses related to oil production and operations that could take advantage of rich gas on a well site. Although rig power provides one of the largest demands for gas use, the heating of drilling fluids during winter months can be achieved with rich gas replacing diesel or propane as the more common fuel. The only technology modification required is a burner modification, provided that gas is already available at the drilling site.

Once drilling is complete, rich gas at the drilling location can be used to provide power for hydraulic fracturing operations. Bi-fuel systems or dedicated natural gas engines can be utilized to provide power for fracturing operations, thereby decreasing diesel deliveries and reducing the fuel costs associated with these operations. Gas availability, in terms of volumetric flow rate, will need to be investigated since the flow available may be insufficient to provide all of the fuel required for fracturing operations. However, in a bi-fuel type application, any shortage of gas would be made up with diesel.

Once production is under way, gas from the producing well or gas transported to the location from nearby wells can continue to be used to provide power for production activities when electrical service is not available. Although the gas use is relatively low for these operations, some remote locations may benefit from on-site generated power. Lastly, wellhead gas could be used to fuel workover rigs used intermittently to maintain producing wells. For workover rigs powered by the truck’s CNG or LNG engine, wellhead gas would not provide a viable alternative. However, workover rigs with separate generators capable of operating on wellhead gas could benefit from the low-cost gas available on location.

Virtually any platform or application that utilizes diesel fuel as part of its operation may warrant the evaluation of using natural gas because of the availability and price of the natural gas. However, there are a number of contractual logistical, technical, and economic components that need to be vetted to determine whether a project makes sense.

Due diligence is required on the part of the reader to evaluate the cost impacts of regulatory, permitting, and engineering design requirements, which were beyond the scope of this report.

APPLICATION III – CHEMICALS DERIVED FROM BAKKEN ASSOCIATED GAS

Overview of NG and NGL-Based Chemical Industry

Raw NG, as produced and flared on well sites, is a mixture of many chemical compounds. The relative amounts of these components vary from well to well and over time from a single well. The potential uses and value of individual components also varies from component to component and over time because of market conditions. What all the components have in common, are high vapor pressures that permit them to escape from the liquids with which they might have been associated.

Raw NG constituents can be classified into three categories: methane, NGLs (also termed condensates), and impurities. Characteristically, the relative amount of a hydrocarbon component is inversely related to its size; thus methane, the smallest hydrocarbon, is predominant, with progressively decreasing amounts of ethane, propane, butane, pentane, hexane, and larger-molecular-weight hydrocarbons. Numerous inorganic compounds are also present, the most common being water, carbon dioxide, hydrogen sulfide, mercury, nitrogen, and helium. By category, NGLs have the highest value, methane less, and contaminants, for the most part, are nuisance waste products. A comparison of the boiling point of major NG hydrocarbons is described in Table 44.

Table 44. NG Component Boiling Points

Component Chemical Name	Chemical Formula	Boiling Point Range, °F
Methane	CH_4	−259
Ethane	CH_3CH_3	−128
Propane	$CH_3CH_2CH_3$	−44
i-Butane	$CH_3CH(CH_3)_2$	14
n-Butane	$CH_3CH_2\ CH_2\ CH_3$	31
neo-Pentane	$(CH_3)_2C(CH_3)_2$	49
i-Pentane	$CH_3CH(CH_3)CH_2CH_3$	82
n-Pentane	$CH_3CH_2CH_2CH_2CH_3$	97
Hexanes	C_6H_{14}	122–156

Each hydrocarbon extracted from raw NG has a set of uses or can be further processed into products. A summary of these uses and products is provided as follows:

- Methane's principal use is as a fuel to produce heat for buildings and chemical and other processes as well as for generating electric power. To a much lesser extent, methane is a feedstock for nitrogen-based fertilizers such as ammonia, urea, and ammonium nitrate; for chemicals such as methanol, acetic acid, formaldehyde, and hydrogen; and for fuels such as dimethyl ether (a potential diesel fuel substitute) and Fischer–Tropsch (FT)-based transportation fuels. In the United States, roughly equal shares of NG deliveries to consumers go to 1) residential and commercial customers, primarily for heating; 2) utilities for electric power generation; and 3) industrial customers for heat and chemical feedstock. (U.S. Energy Information Administration, 2012b).

- Ethane is primarily used as a chemical feedstock for production of ethylene and derivatives such as polyethylene, ethylene glycol, and ethylene oxide. When feedstock prices are depressed relative to fuel prices, ethane also can be rejected into NG pipelines to the extent allowed by pipeline operators.

- Propane's primary use is residential and commercial heating with the remainder being used by 1) industry for chemical feedstock and other uses, 2) agriculture for heating and drying, and 3) commercial entities as a motor fuel for forklifts and other vehicles. Of propane consumed in the United States in 2010, about half was used for residential and commercial heating and a third for chemical feedstock for chemicals such as propylene and polypropylene (Lippe, 2011).

- There are two forms of butane (n-butane, a straight chain hydrocarbon, and i-butane, a branched hydrocarbon) that possess slightly different chemical properties and uses. The majority of butanes are used for heating when alone or combined with propane to create liquefied petroleum gas (LPG) and as petroleum refinery feedstock, eventually becoming motor fuel. Regulatory restrictions on motor fuel vapor pressure, however, limit butane levels, especially during the summer and in blends containing ethanol. As a result, refiners convert butanes to other compounds, such as conversion of i-butane to higher-octane compounds by route of alkylation and to MTBE (methyl tertiary butyl ether) (an oxygenate) before blending into motor fuel. Additionally, butanes are used as refrigerants and as feedstock to produce chemicals and materials such as polybutylene plastic and polybutadiene synthetic rubber.

- Pentanes, hexanes, and larger hydrocarbons are often referred to collectively as "natural gasoline." These components typically become refinery feedstock, often with upgrading to higher-octane fuels, and eventually appear in motor fuel. To a lesser extent, individual components are used as feedstock and solvents for chemical and food processes, as refrigerant, and as blowing agent for production of polystyrene foam, to name a few. Increasingly, natural gasoline, with some butane included, is being transported to Canada to dilute bitumen crude oil so as to reduce the oil's viscosity and enable it to be pumped in pipelines.

Figure 37 describes the supply chains for natural gas and NGLs from the well site to the distribution system. As is apparent, the NGL chain is longer and also is much more complicated because of the multiplicity of components that comprise NGLs and the range of products.

The NGL supply chain starts with production, the predicted geographic concentration of which is represented in Figure 38. Raw natural gas is collected at well sites and sent through gas-gathering networks to gas-processing facilities in which the raw gas is treated, NGLs extracted, and pipeline-quality natural gas produced. Typically, these activities are accomplished in gas-processing facilities close to where natural gas is produced. Fractionation, or separation of the discrete NGLs, can be performed at the gas-processing plant as a means of separating them

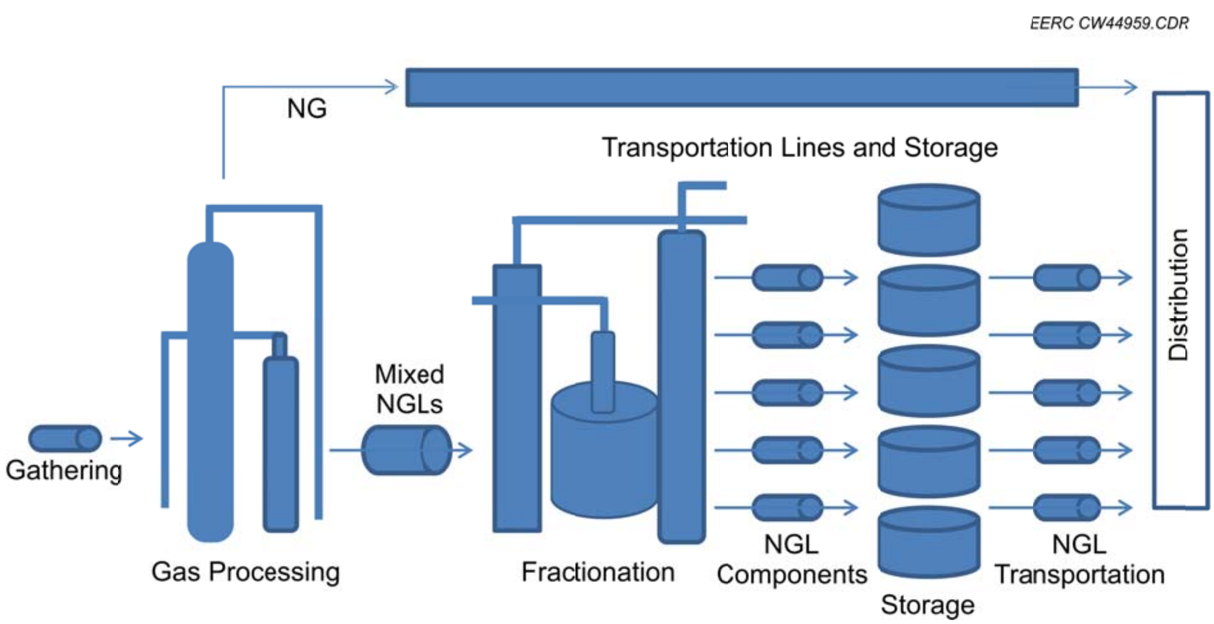


Figure 37. NG and NGL supply chain.

Figure 38. Lower 48 states' shale plays (2011).

from methane, or a mixed NGL stream can be transported to remote facilities, such as Conway (KS) or Mt. Belvieu (TX), Channahon (IL), Sarnia (ON), Fort Saskatchewan (AB) and Joffre (AB).

Once fractionated, pure NGL components are moved separately by multiple pipelines, batched in a shared pipeline (which requires substantial storage as each component awaits its turn to travel), or moved by rail. Components on the U.S. Gulf Coast (USGC) do not have to be transported far to reach petrochemical facilities and refineries. Components in Conway have farther to go to get to the USGC or to crackers in Illinois and Iowa, but pipelines are in place and more are being constructed to move the increasing volumes of components, especially towards the USGC.

NG-Processing Infrastructure

In 2010, the United States had 493 operational NG-processing plants that had a combined daily capacity of 77 billion cubic feet (Bcf). Figure 39 depicts the location and size of these facilities. Figure 40 classifies the plants by capacity, then describes the number of plants in each class and the cumulative capacity of plants within each class. EIA data indicate that the largest nine plants accounted for 31% of U.S. gas-processing capacity. NG processing is concentrated on the USGC. In 2010, Texas had the largest number of plants, 163, and processing capacity of 19.7 Bcf/day, representing 26% of total U.S. capacity. Texas and Louisiana were responsible for 28% and 14%, respectively, of total U.S. processing in 2010. During this same period, North

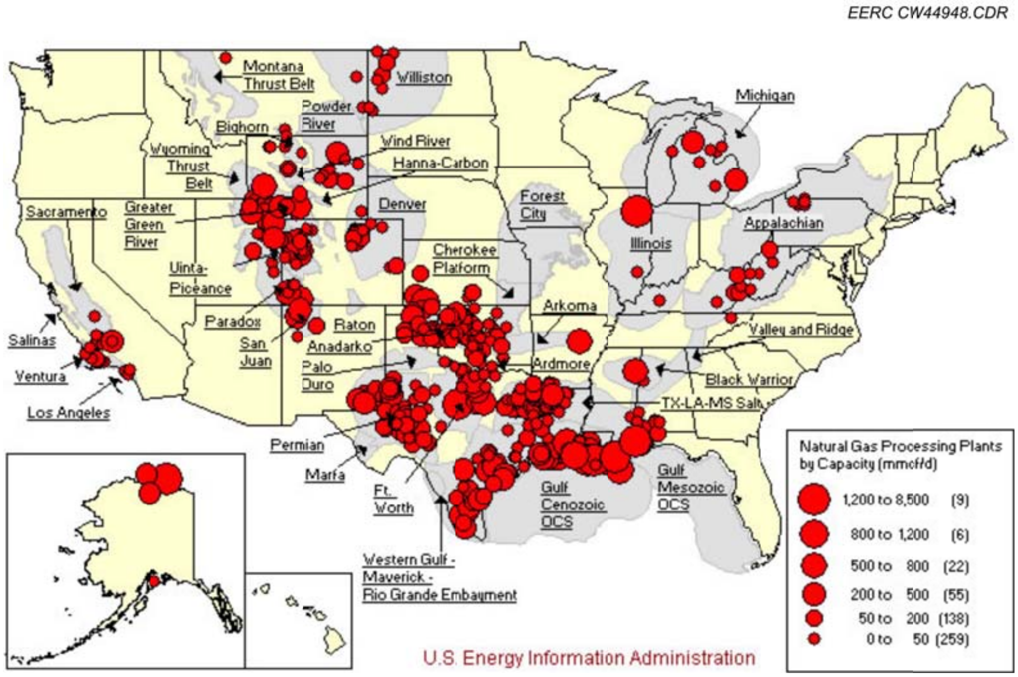


Figure 39. U.S. NG-processing plants (2009).

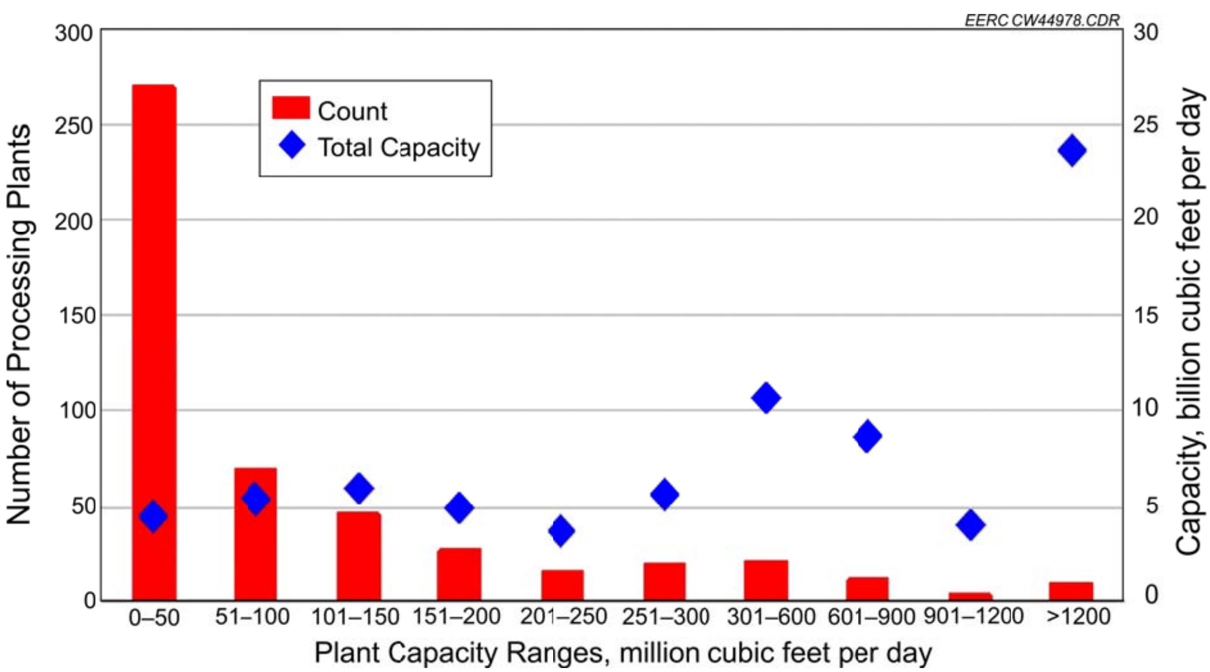


Figure 40. Capacities and number of U.S. NG-processing plants (2010).

Dakota processed about 0.6% of the U.S. total. Two other regions performed significant processing in 2010: Alaska (17%) and the Rocky Mountain region (Colorado and Wyoming had a combined output of 18% of U.S. processing). Texas's disproportionate processing (26% of U.S. capacity, but 28% of output) was due to its operating at 83% of capacity—while the rest of the country averaged 66%—which indicates an efficient use of resources and potential upcoming need to expand capacity. During the period 2004–2009, average plant capacity increased from 114 to 139 MMcfd.

Figure 41 exhibits the locations of processing plants in North Dakota in 2011. The number and capacity of plants in the state is forecast to increase substantially between 2006 and 2012 as projected in Table 45.

Because of expansion in gas-gathering and processing infrastructure, flaring of NG is declining in North Dakota, having peaked in 2011 with 35% of gas being flared. In April 2012, North Dakota Department of Mineral Resources statistics showed NG production was up to 650,000 Mcfd, with 34% being flared. As new gas-processing plants are built and commissioned in 2012, the fraction of gas flared is expected to decrease (Persily, 2012).

NG Distribution Infrastructure

As Figure 42 indicates, three interstate NG transmission pipelines pass through and are accessible within North Dakota. These include WBIP, which extends through eastern Montana, northern Wyoming, western South Dakota, and across North Dakota; NBIP, which connects to an Alberta collection system in Montana and extends through the Dakotas, Minnesota, Iowa, and Illinois to northwest Indiana; and the Alliance Pipeline, which extends from British Columbia through North Dakota, Minnesota, and Iowa to Illinois. The capacity of the three pipelines is adequate to absorb North Dakota's growing NG production—which has expanded by 24 MMcf/month over the past year—for an extended period of time. Growth will be handled by the addition of receipt and delivery points, increased compression, and increased ethane rejection without expanding or replacing trunk pipelines.

In 2008, WBIP added 42 MMcfd (expandable to 60 MMcfd) to its system and has proposed adding roughly 20 MMcfd of delivery capacity in northwestern North Dakota to be constructed later this year.

NBIP, with a current capacity of 2.401 Bcfd of which 2.171 Bcfd is contracted firm, will be receiving NG from ONEOK's three new 100-MMcfd processing plants and will commence service in 2012–2013. The incremental load of these plants on the NBIP will be attenuated somewhat by ONEOK's construction of a 60,000-bpd NGL pipeline that will connect to William's Overland Pass Pipeline in Colorado. ONEOK's pipeline will permit capture of valuable ethane that otherwise would be rejected into the NG product and result in NG flow reduction of up to 20%.

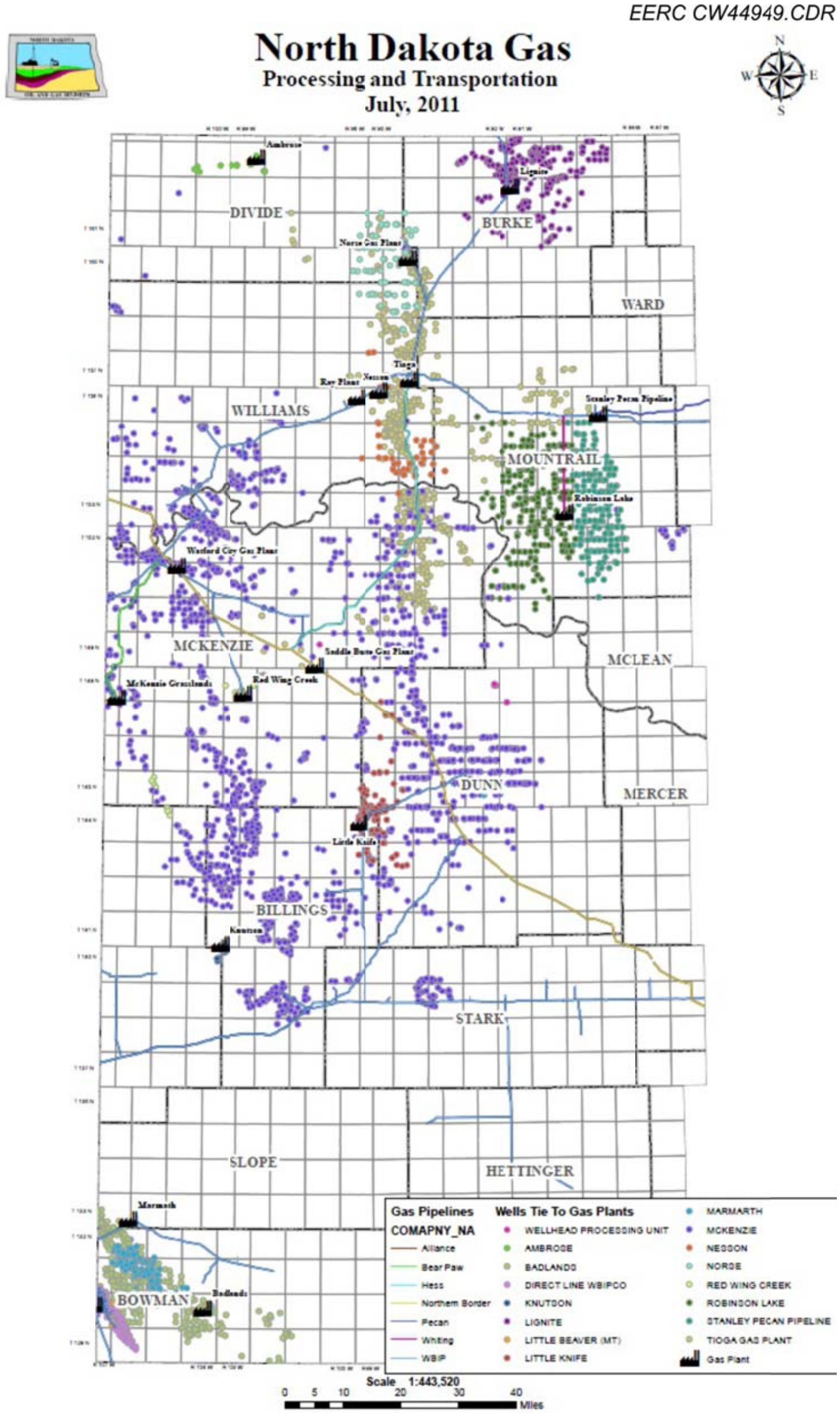


Figure 41. North Dakota gas-processing and transportation (North Dakota Pipeline Authority, 2011a).

Table 45. North Dakota NG-Processing Capacity (2006–2012), in million cubic feet per day

2006	2008	2010	2011	2012
227	380	500	670	1100

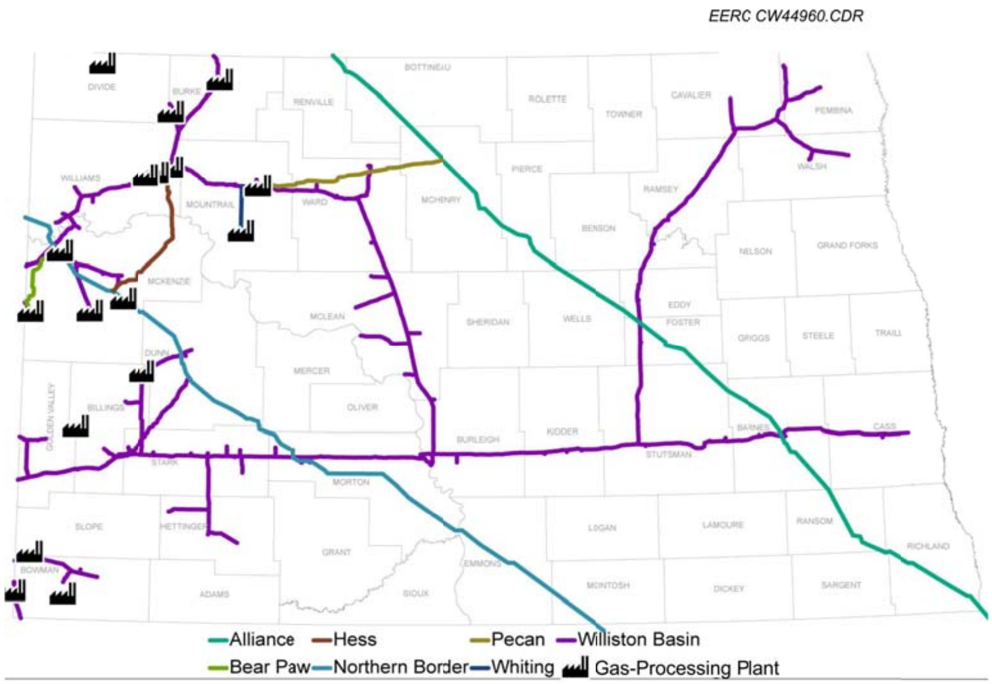


Figure 42. Interstate NG pipelines in North Dakota.

The Alliance Pipeline, with a FERC-certified capacity of 1.513 Bcfd, is a high-pressure, rich gas pipeline. Currently the pipeline's only U.S. receipt point is Prairie Pipeline's connection at Bantry, North Dakota; however, a new pipeline from Hess's Tioga gas plant to Sherwood, North Dakota, will add a second point. This construction is in conjunction with expansion of the Tioga plant, which will more than double the plant's capacity, and construction of an ethane pipeline by Aux Sable, named the Vantage Pipeline, that will transport up to 60,000 bpd (more than 90 MMcfd) of ethane to cracking facilities in Alberta.

If NG production growth continues as it has recently, production will exceed 1000 MMcfd by August 2013 and 1100 MMcfd by January 2014. As indicated in Table 46, the forecasted NG-processing capacity in North Dakota should be adequate to handle the new production.

Current NGL Distribution Infrastructure

Currently, Bakken NGLs are transported out of state by rail and by pipeline via the Prairie Rose Pipeline. Operated by Aux Sable, the Palermo Conditioning Plant near Stanley, North Dakota, removes heavier NGL components to provide a 110-Mcfd rich gas stream to the Prairie

Table 46. NG-Processing Capacity in North Dakota, MMcfd

Owner Company	Facility	County	2006	2008	2010	2011	2012	2013
North Dakota			6					
Bear Paw/ONEOK	Lignite	Burke	7.5	6	6	6	6	6
Bear Paw/ONEOK	Marmath	Slope	NA	7.5	7.5	7.5	7.5	7.5
Bear Paw/ONEOK	Garden Creek	McKenzie	NA	NA	NA	100	100	100
Bear Paw/ONEOK	Stateline 1	Williams	NA	NA	NA	NA	100	100
Bear Paw/ONEOK	Stateline II	Williams	32	NA	NA	NA	100	100
Petro Hunt	Little Knife	Billings	4	32	32	32	32	32
True Oil	Red Wing Creek	McKenzie	0.5	4	4	4	4	4
Sterling Energy	Ambrose	Divide	NA	0.5	0.5	0.5	0.5	0.5
EOG Resources	Stanley	Mountrail	NA	20	0	0	0	0
Whiting Oil and Gas	Robinson Lake	Mountrail	NA	30	45	90	90	90
Whiting Oil and Gas	Ray	Williams	NA	10	10	10	NA	NA
Whiting Oil and Gas	Belfield	Stark	NA	NA	NA	30	30	30
XTO–Nesson	Ray	Williams	63	10	10	10	10	10
Bear Paw ONEOK	Grasslands	McKenzie	110	100	100	100	100	100
Hess	Tioga	Williams	4	120	120	120	250	250
Hiland Partners	Badlands	Bowman	NA	40	40	40	40	40
Hiland Partners	Norse	Divide	NA	NA	25	25	25	25
Hiland Partners	Watford City	McKenzie	NA	NA	NA	50	50	50
Summit Resources	Knutson	Billings	NA	NA	NA	NA	NA	NA
Saddle Butte	Watford City	McKenzie	NA	NA	NA	45	45	45
Plains	Ross	Mountrail	NA	NA	NA	NA	NA	50–75
Aux Sable – Chicago, IL								
Aux Sable	Prairie Rose	Mountrail	NA	NA	110	110	110	110
		Total	227	380	510	780	1100	1150–1175

Rose Pipeline which connects to the Alliance Pipeline, carrying gas to facilities in Channahon, Illinois. Pipeline capacity is expandable. A truck rack capable of receiving 5 Mbpfd (expandable to 10 Mbpd) of mixed NGLs was added to the Palermo Plant in April 2012. Early in 2013, Vantage Pipeline should be in operation, transporting 40–60 Mbpd of ethane from Hess's Tioga gas-processing plant by pipeline to Canada. By mid-2013, Alliance Pipeline's 79-mile lateral from the Tioga plant to Alliance's mainline near Sherwood, North Dakota, should be in service, with an initial capacity of 120,000 Mcfd of rich NG to facilities in Channahon, Illinois. Also by mid-2013, ONEOK's 525-mile pipeline from western North Dakota to the Overland Pass Pipeline in northern Colorado should be in service, with an initial capacity of 60 Mbpd (expandable to 100 Mbpd) of mixed NGLs to facilities near Conway, Kansas.

The Kinder–Morgan Cochin Pipeline, the only NGL pipeline in North Dakota, is shown in Figure 43. It has a single terminal in the state that is a propane delivery point located at Carrington, which has 21,430 bbl of storage on-site. In addition to Kinder–Morgan's pipeline, however, Alliance Pipeline operates a rich NG pipeline between British Columbia and Illinois that passes through North Dakota and transports light NGL components mixed with NG through North Dakota.

Figure 43. Alliance Pipeline system map (Alliance Pipeline LP, 2012).

If NGL pipeline transportation is not available, midstream companies have the option of transporting NGLs by rail or fractionating and shipping components by rail. Rail has an advantage in that one train can ship multiple NGL components as cheaply as NGLs, whereas transporting components by pipeline might involve multiple pipelines. The difference between the price received for NGL components and that paid for the original mixed NGLs is termed the "frac spread" (A similar term, NGL margin, refers to the same difference for propane and heavier components). This value varies over time on the basis of NG, crude oil, and petrochemical prices and by location and access to product markets. In 2002, frac spreads were in the neighborhood of $1/MMBtu, but in 2011, they were in the neighborhood of $6–$8/MMBtu. Frac spreads can also differ between locations such as Conway, Kansas, and Mt. Belvieu, which differed by 3 cents/MMBtu on July 25, 2011. In general, Conway and Mt. Belvieu move together but with a discount offset because of Conway's distance from the USGC market.

Given their limited access to NGL pipelines, North Dakota gas processors have tended to fractionate and produce NGL components, instead of shipping mixed NGLs. Figure 44 depicts the increase in NGL production over time and shows how small Y-grade (mixed) NGL production is compared to fractionated components. It also indicates that ethane is not fractionated, but stays with the NG.

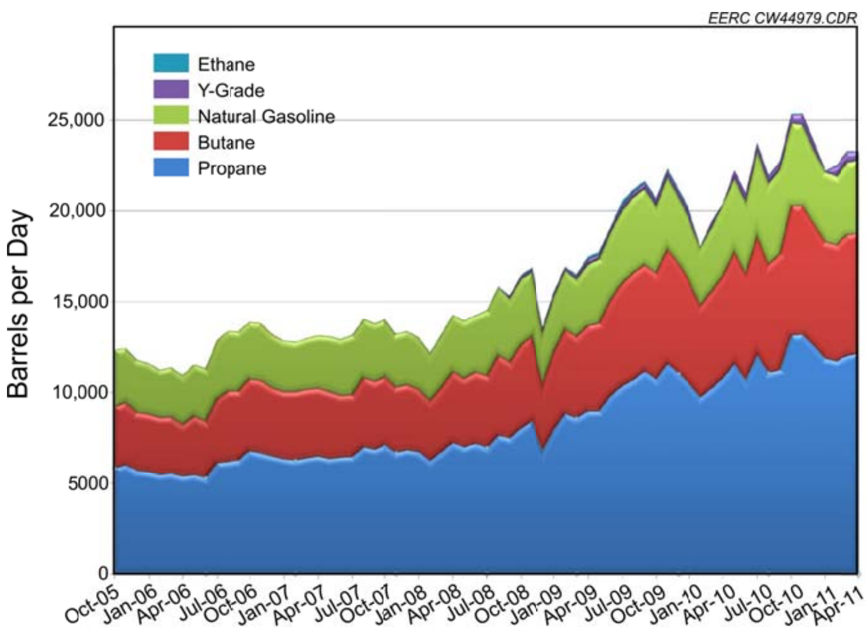


Figure 44. North Dakota NGL production (bpd) (North Dakota Pipeline Authority, 2011).

Alternate Rich Gas Distribution System

Another means of transporting lower-molecular-weight NGLs is by means of rich-gas pipelines, which are pipelines that permit introduction of higher-Btu-value gases (i.e., methane mixed with higher concentrations of NGLs). The Alliance Pipeline that runs from British Columbia, Canada, to the Chicago area is an example of such a pipeline: it provides transport of lighter NGLs with methane to a site where recovery and fractionation of NGL components occur.

Petrochemical Industry Relevance in North Dakota

North America has four major petrochemical centers: the Mt. Belvieu (TX) and Conway (KS) hubs, Edmonton (AB), and Sarnia (ON). Mt. Belvieu's capacity far exceeds the other regions and is considered the price reference point for North American NGLs. Mt. Belvieu has an NGL storage capacity of 200 MMbbl; Williams operates storage in Conway with a 20-MMbbl capacity. Alberta's AEGS (Alberta Ethane-Gathering System) has a 5-MMbbl capacity. BP operates 12 salt caverns in Sarnia that hold finished products and possess a capacity of 5.0 MMbbl (6.8 MMbbl of surface brine pond capacity). EIA reported PADD (Petroleum Administration for Defense Districts) III (including the USGC) August 2011 NGL inventory to be 74.7 MMbbl, which is only a 37% utilization rate, suggesting additional storage capacity exists to support the growing shale gas production.

Traditionally, the North American petrochemical industry has been located in areas that possess large gas reserves and geologic storage features like salt domes and depleted reservoirs where gas, NGLs, and intermediate products can be stored in very large quantities. Currently, 96% of U.S. ethane-cracking capacity is concentrated on the USGC, especially Texas and Louisiana. As illustrated in Figure 44, the USGC possesses a large fraction of gas reserves and, as mentioned previously, has significant geologic storage capacity to accommodate the industry. Based on these factors, significant infrastructure has been built around the USGC. Distribution capacity exists to transport gas and gas liquids to the region from across North America. Additionally, NGL fractionation, cracking, and downstream processing capacity exist to convert these hydrocarbons into products that are shipped around the world. As a result of the large volume of gas and NGLs processed in the region, it has become the basis and reference point for financial markets.

As described herein, chemical production capital investment decisions are complex, involving a myriad of factors, relationships, and timing that consider complete supply chains. A detailed discussion of how market factors impact the petrochemical industry and plans for infrastructure expansion is provided in Appendix A. Such factors include the following:

- Capital efficiency
  - Economy of scale (larger units are cheaper to build/operate per pound of product)
  - High utilization rates (run constantly at full throughput)
  - Long life (operate plant for decades)
  - Use of synergies to reduce required investment, such as restarting shuttered plants, converting units from petroleum-based feedstock to NG-based feedstock, relieving capacity constraints in existing plants, and sharing facilities

- Proximity to long-term:
  - Cheap and abundant feedstock and utilities
  - Large customer markets
  - Cheap transportation
  - Cheap storage

- Government regulatory and business climate, plus grants and tax incentives

Chemicals in North Dakota can be produced at two different locations, the well site and downstream of gas processing, each of which has different advantages and issues. The principal advantage of well site chemical production in North Dakota is access to cheap gas that would otherwise be flared. This advantage, however, is temporary, existing only until infrastructure appears. Agricultural chemical production, such as fertilizer, possesses an additional advantage of a local product market. Two significant disadvantages of well site chemical production are lack of economy of scale and decreasing utilization because of production decline over the life of a well. The production processes with the best opportunity for economic success at the well site are simple processes, such as NGL collection or processes that manufacture products for which a local market exists and are suited for downsizing to small scales, such as novel fertilizer production technologies or innovative gas-to-liquid approaches that can capitalize on the price difference between gas and liquid transportation fuels. All such processes would benefit by being mobile to periodically relocate to better-producing wells and avoid reduced utilization rates.

North Dakota's NGL production is forecast to be adequate to support NGL-based chemical manufacturing. Based on the generic raw NG composition that was presented earlier in this report and at the 600,000-Mcfd raw NG production level, adequate ethane and propane (120,000 bpd) could be produced to support two world-scale crackers. At 900,000 Mscfd, three world-scale crackers could potentially be supported. If constructed, it is likely that polymerization or chemical plants would also be constructed to convert the output into plastics and chemicals. Such construction, however, would be contrary to the petrochemical industry's proclivity to build processing facilities on and transmit feedstock to the USGC.

A construction decision in North Dakota would benefit from many factors discussed previously, including large geologic storage, downstream processing capacity, transportation routes for products, and supporting infrastructure. Currently, much of the needed infrastructure does not exist, and as such, pipeline and rail export to existing industry hubs has been the standard practice. A chemicals industry could develop in North Dakota that could use pipeline NG feed to produce chemicals of regional interest or produce niche NGL-based chemicals, but it is unlikely that investment for a conventional petrochemicals industry could be attracted unless profound improvements were made to resolve critical issues.

Conceptual Chemical Production in North Dakota

Chemical production near well sites has distinct benefits and disadvantages. Benefits include access to NG that would otherwise be flared, which could provide an economic advantage of cheaper NG feedstock and an environmental benefit of avoiding flaring, and production of chemicals that can be used locally, such as ammonia and motor fuel, which reduces costs and safety risks associated with long-distance transport. A major disadvantage is the greater unit cost of producing at smaller scales. The following considers production of ammonia and FT motor fuel from NG that would otherwise be flared at Bakken well sites.

Of the Bakken wells that flared in December 2011, the largest two flared more than 2000 Mcfd and the median flared about 320 Mcfd. Economy of scale drives toward constructing and gathering from the largest producing sites. However, NG production characteristically declines over time which would result in underutilization of the equipment if the plant was designed to capture at initial production rates. This effect and that of varying NG price are depicted in Table 47, which shows estimated capital and operating costs for ammonia production based on a design described in Appendix B. The NG feed is assumed to be that of the rich gas composition discussed earlier in this report.

Table 47. Ammonia Production Cost Estimate at Different Scales and Rates

	Large Unit/Large Flow	Large Unit/Small Flow	Small Unit/Small Flow
NG Feed Rate, Mscfd	2000	320	320
Capacity, ton/day	90.1	90.1	14.4
Production, ton/year	31,227	4,996	4,996
Utilization Rate, %	95	15	95
Existing Technology			
Fixed Capital Investment, $	52,389,617	52,389,617	17,385,099
Product Cost ($0 rich gas), $/ton	305.71	1288.91	517.56
Product Cost ($4 rich gas), $/ton	395.71	1378.91	607.56
Product Cost ($8 rich gas), $/ton	485.71	1468.91	697.56

The wellhead prices represent those if flared gas were free, if it were sold at EIA's forecast price for the 2015–2020 period, and if it were sold near the peak price in 2005.

While the above data were intended to be realistic, it is likely that they are optimistic, which is characteristic of early-stage cost estimates. Despite this, several observations may be made from the data:

- Economy of scale is evident as the larger flow achieves lower production cost.
- No ROI assumed.
- The deleterious effect of underutilization is evident as the capital cost of an oversized unit substantially increases the unit production cost; underutilization, of course, can occur even if the unit is not oversized because of downtime or loss of the unit before the end of its 20-year depreciated life.
- NG price can significantly impact production cost.
- General expenses (sales, administrative, research and engineering) at the 1% of sales level have little impact on product cost.
- While large-scale units are routinely constructed and operated, units at this scale are not routinely manufactured or operated so should be considered developmental items.

When compared to production rates of industrial ammonia plants, which have grown from about 200 tons/day in the 1950s to 2200 tons/day in design in 2002, well site units are miniscule and disadvantaged. Novel technologies, such as H2Gen's compact reformer, may provide a way to reduce capital cost from smaller-scale systems and reduce this handicap. The size and complexity of a plant at even the 14-ton/day scale is too large to be considered portable—moving such a plant would be possible, but expensive and time consuming.

The U.S. Department of Agriculture Economic Research Service has reported that average U.S. farm prices for anhydrous ammonia have risen from \$250/ton 10 years ago to \$783/ton in March 2012. The above analysis indicates that a 10% before-tax return on investment is possible, even at a 320-Mcfd feed rate, with appropriate technology, and low NG feedstock and general expenses. It should be noted, however, that in 2008, ammonia prices were at \$755/ton but fell to \$499/ton 2 years later, which likely would result in a negative return on investment for a small unit. These economics could be favorably impacted if fines were imposed on flaring and producers would pay a charge to dispose of the NG. Ultimately, the economics will have to compete with wellhead prices as gas gathering is deployed.

In addition to ammonia, another product derived from NG that has a local market in the Bakken is liquid motor fuel. On an energy basis, NG traditionally is priced less than crude oil, recently by as much as one-tenth the price of crude on the spot market. Consequently, the opportunity exists for a significant upgrade in value if NG could be converted inexpensively to a petroleum product such as diesel fuel. A process discovered in the 1920s—the FT process—is the preferred means of accomplishing this conversion and offers the prospect of providing a high-quality, low-sulfur diesel fuel into a region that is experiencing tight supplies. Unfortunately, the capital cost associated with FT fuels production is high even at very large scale. Currently, there are five gas-to-liquids (GTL) plants in the world:

- Shell's \$1 billion 14,700-bpd Bintulu (Malaysia) facility
- Sasol's \$250 million 10,000-bpd GTL Mossgas (South Africa) plant (the low capital cost of the plant likely is due in part to its location within a larger coal-to-liquids facility with which it can share resources.)
- Sasol's \$1 billion 34,000-bpd Oryx (Qatar) plant
- ChevronSasol's \$8 billion 33,000-bpd Escravos (Nigeria) facility
- Shell's \$19 billion 140,000-bpd GTL and 120,000-bpd NGL Pearl (Qatar) plant

It should be noted that the Escravos plant is about a decade late and costs five times the original estimate. Scaling down such technology to a 320-Mcfd unit would produce about 32 bpd of FT liquids and likely be exorbitantly expensive when scaled down. A few companies have claimed to be developing novel small-scale technologies that might be applicable.

Velocys is a microchannel equipment developer that has been working on GTL technology for more than a decade. The company has three demonstration units under way: 50-bpd and

25-gallon/day biomass-to-liquids units in Brazil and Austria, respectively, and a 6-bpd GTL unit in Brazil. Heatric (a subsidiary of Meggitt), which is well known for its compact heat exchangers used on oil platforms, claims to have developed hydrogen reactors and studied GTL. CompactGTL, a relatively new microchannel equipment developer, is developing equipment especially for associated gas and is currently demonstrating a unit in Brazil. Other possible developers include IMM, KarlsrubeFZK, Corning Degussa/Evenik, Alfa Laval, and Chart. Some developers claim that their units at small scale can be skid-mounted, so they have some mobility. Despite this and the possibility that their technologies might be more economical at small scale than conventional technologies, their technologies are untested at this time and their economics estimates subject to large errors.

OVERALL STUDY CONCLUSIONS

This study concludes that of the four alternatives (NGL removal, CNG, power generation, and chemical production) investigated as viable end use technologies for using nontraditional NG, only two hold near-term promise – NGL removal and distributed power generation. All of the technologies, regardless of likelihood of deployment at small scale, have the potential to reduce, but not eliminate, the number of flares and the amount of flared associated gas in North Dakota (to varying degrees). A summary of all evaluated technologies with their pertinent characteristics is provided in Table 48.

Table 48. Summary of Evaluated Technologies with Qualitative Characteristics

Technology	Gas Use Range, Mcfd	NGL Removal Requirement	Scalability to Resource	Ease of Mobility	Likelihood of Deployment at Small Scale
Power – Grid Support	1000–1800	Minimal	Very scalable	Mobile	Very likely
Power – Local Load	300–600	Minimal	Very scalable	Mobile	Very likely
CNG	41 Mcfd/million mile fleet	Yes	Scalable	Mobile	Possible
Chemicals	>2000 Mcfd	No	Not scalable	Not mobile	Very unlikely
Fertilizer	300–2000	No	Scalable	Potentially mobile	Possible
GTL	>2000 Mcfd	No	Scalable	Potentially mobile	Possible

NGL removal will not single-handedly reduce the number of flares, but it will reduce the overall quantity of flared gas and will create a viable secondary revenue stream for wells for which gathering pipelines have not yet been installed. In fact, several companies are now pursuing this business opportunity within the Bakken region.

Distributed power generation seems to best match the scale of the flared gas resource available, and can utilize the flared gas almost as is, with little cleanup necessary. Distributed power has the capability to provide grid support and increase reliability in the rural areas of North Dakota currently experiencing the highest levels of activity related to oil exploration. However, the evaluation of power generation scenarios assumes that adequate electrical infrastructure exists to accommodate the additional electricity these systems generate.

The CNG application could be pursued, but requires extensive gas cleanup and polishing activity to achieve the gas quality levels currently demanded by engine providers. The CNG application also requires a fleet with some flexibility to follow the flared gas opportunities where they exist. More appropriate for CNG application is implementation at existing downstream gas supply for fleets of sufficient size to achieve significant financial benefit.

Finally, the chemical production application holds the least promise of any applications investigated. This has much to do with supply chain logistics, and lack of demand for producible products in the upper Midwest. Chemical production tends to be tightly centered in petrochemical hubs, where all inputs are readily available, and a nearby pipeline for products is readily available. With that said, the production of nitrogen-based fertilizers (a subset of chemicals) may hold some promise at small scale.

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- IMW/Clean Energy – Chris Damiani
- Landi Renzo USA – Marco Genova
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APPENDIX A

OVERVIEW OF PETROCHEMICAL INDUSTRY INFRASTRUCTURE

OVERVIEW OF PETROCHEMICAL INDUSTRY INFRASTRUCTURE

ECONOMIC CONDITIONS

The global economic downturn of 2008–2009 reduced natural gas liquid (NGL) consumption during that period, the extent of which varied by region. As Table A-1 depicts, U.S. ethylene production peaked in 2007; whereas, Taiwan and China ethylene production fell slightly in 2008 but recovered and set records the following two years. In that environment, expansion of ethylene production was moving away from the United States toward areas of increasing demand such as the Far East and areas possessing feedstock advantages, such as the Middle East.

Underlying the Middle East feedstock advantage was the perception that the United States would increasingly import NG. In 2006, North America (excluding Puerto Rico) had five operating liquefied NG (LNG) import terminals, with 17 more approved and 25 awaiting approval. At that time, there was only one export terminal in Kenai, Alaska, which has since been shutdown. Expectation of such importing implied expectations of limited domestic NG production increases and associated NGL production increases, as well as higher prices for both. Even with increased NG flow into the United States in the form of LNG, since LNG is generally more than 92% methane, NGL processing expansion opportunity was limited.

Table A-2 portrays the difficulties that NG and NGL markets faced in the early to middle portion of the 2000s. NG prices were relatively high compared to those of its products and competition. Industrial NG prices averaged \$4–\$6/Mcf in 2002–2003, but increased to \$7–\$9/Mcf in 2005–2006, and were headed higher. Additionally, NG price was about two-thirds of petroleum on an energy basis and the frac spread (i.e., the price of the fractionated products over the cost of the feedstock) was about \$1/MMBtu.

Exemplifying these economic conditions, production capacity was static or declining in the United States. In the case of NG-based chemicals, such as ammonia and methanol, production decreased by 41% and 89%, respectively, during the period 2000–2007. In the case of NGL derivatives, *Chemical & Engineering News* reported that, during the 2000s, U.S. petrochemical executives expected that “. . .investment of capital in domestic petrochemical plants would be limited mostly to maintenance.”

Table A-1. Annual Ethylene Production Rates Compared to 2007 Base Year (American Chemical Society, 2011)

	2007, metric tonnes/year	2008 Rate, %	2009 Rate, %	2010 Rate, %
United States	25,412	−11	−11	−6
Taiwan	3666	−1	5	7
China	10,477	−2	2	35

Table A-2. U.S. NG and NGL Market Comparison over Time

	Early–Mid-2000s	2011
Industrial NG Prices, direction	$7.82/Mcf (up) (2006)	$5.02/Mcf (down)
Relative Value of NG to Crude	60%–65% (2003)	30%–35%
Frac Spread	$1/MMBtu (2002)	$6–$8/MMBtu
Direction of NG Movement	Importer	Exporter
Direction of Olefin Production	Contracting	Expanding

This situation changed dramatically during the 2000s as advances in drilling horizontal well bores and hydraulic fracturing made petroleum trapped in shale formations economically accessible. The increased U.S. NG production due to these methods has profoundly reduced the price of NG and associated liquids, especially relative to its crude oil-based competition, at a time when NGL-derived products have maintained their value. The effect is expanded investment in NG and NGL infrastructure in the United States and the potential reversal in direction of trade from increasing LNG imports to expanding LNG exports. Thus, while today there are 12 operating LNG import terminals in the United States (plus one in Puerto Rico), three of those are now approved to export LNG, with at least one additional pursuing approval to export.

Extracting maximum return from a resource such as NG requires an efficient supply chain; inadequacies or inefficiencies in distribution or production systems reduce the value of the resource. The term “stranded” has been coined to describe extreme cases where valuable resources are inaccessible or transportation cost-excessive. Thus the value of resources depends upon the efficiency of their supply chains.

Major determinants of the efficiency of chemical processes are the scalability of the process, installing the maximum size and operating near capacity – that is to say, design, install, and operate to maximize economy of scale. Major determinants of efficient storage and transportation are to use the cheapest storage technologies and locations, to minimize transportation distances, to use the cheapest transportation modes, and to operate near capacity. Other factors would be to take maximum advantage of synergies with existing facilities and to integrate multiple steps. In practice, 60% of U.S. ammonia production capacity is located in Louisiana, Oklahoma, and Texas because of proximity to NG feedstock. In the case of polyethylene plastic, more than 95% of ethane-cracking (ethylene production) capacity is in Louisiana and Texas, again in part because of proximity to petroleum and NGL feedstock. In 2004, petroleum comprised about 55% of the ethylene feedstock.

Recently, however, with the cash cost of making ethylene from ethane at 18 cents/pound and from light naphtha at 46.5 cents/pound, ethane makes up 70% of ethylene production. The appearance of substantial production from the Marcellus and Bakken Formations has had relatively little influence on plans for constructing future facilities in those areas as only one of five petrochemical companies that have announced plans to construct major new petrochemical complexes have decided to locate outside of Louisiana and Texas. Only Shell has announced construction outside of the U.S. Gulf Coast (USGC), recently selecting Pennsylvania for a new facility.

Shell's decision came under criticism by participants at a September 2011 Platts-sponsored NGL Forum for various reasons, such as disposition of feed when the facility is processing at reduced rates. Feed can go to storage at Henry Hub or to the many other nearby petrochemical complexes if one USGC complex cannot accept feed – without such infrastructure around it, where will Shell send its feed? To take advantage of its proximity to northeastern customers, Shell also is considering constructing a polyethylene plant with the cracker; otherwise, it would have to transport its ethylene to a polymer plant.

This would not be necessary on the USGC, since polyethylene plants and infrastructure already exist there. The decision could also be considered risky during periods that West Texas Intermediate (WTI) petroleum prices fall relative to NGLs: in situations when refinery feedstock is cheaper than NGLs, the USGC is advantaged because 1) it has many more refineries than the East Coast (45% of which are for sale or shutting down) and 2) recently its WTI feedstock has been cheaper than the Brent crude oil processed by East Coast refineries.

Existing Infrastructure

There are relatively few NGL pipelines as compared to NG and crude oil pipelines in the United States. With the exception of a couple of pipelines extending from Texas to New York and Texas to North Carolina, locations of North American component pipelines tend to reside within a "V" emanating from Texas northwestward to Alberta and from Texas northeastward to eastern Ontario, with the highest concentration lying between Kansas and the Texas Gulf Coast, as indicated by the PennWell LPG and NGL and Phillips 66 propane pipeline system maps shown in Figures A-1 and A-2.

Enterprise Products Partners LLP owns or has interest in 15,600 miles of mixed NGL pipelines, 160 million barrels of usable storage capacity, and 619 thousand barrels per day of fractionation capacity in the central part of the United States, as shown in Figure A-3. The far eastern line is a propane pipeline that has not been included in the cumulative pipeline distance. Additionally, Enterprise Products operates a number of NGL storage facilities described in Table A-3 and NGL fractionation facilities described in Table A-4.

Phillips 66 conducts its Midstream business primarily through a joint venture, Dakota Catalyst Products, Inc., Midstream LLC. DCP Midstream's assets include 62,000 miles of pipelines, 61 gas-processing plants and 12 NGL fractionators. In 2010, DCP Midstream extracted 193 thousand barrels per day (Mbpd) of NGLs through fractionators in Mt. Belvieu, Texas (50 Mbpd), Conway, Kansas (43 Mbpd), and Gallup, NM (26 Mbpd), as well as other assets in Trinidad, the Caribbean, and Central America. Phillips 66 (previously the midstream and downstream segments of ConocoPhillips) also owns substantial pipeline assets, as indicated in Figure A-4.

The Cochin (Dome) pipeline system (Figure A-5) is a 1900-mile, 12-inch-diameter multiproduct pipeline owned by Kinder–Morgan operating between Fort Saskatchewan, Alberta, and Windsor, Ontario, including five terminals. Operating on a batched basis, the system has an

Figure A-1. PennWell LPG/NGL pipeline and facilities map of the United States and Canada (Penwell, 2012).

Figure A-2. Phillips 66 (previously ConocoPhillips) propane pipeline map (ConocoPhillips, 2012).

Figure A-3. Enterprise Products mixed NGL pipeline map (Enterprise Products, 2012).

Table A-3. Enterprise Products' NGL Storage Capacity

State	Usable Storage Capacity, million bbl
Texas	120.7
Louisiana	13.5
Kansas	8.4
Mississippi	7.8
19 Other States	9.6

Table A-4. Enterprise Products-Owned NGL Fractionation Capacity

Facility	Ownership Interest, %	Gross Capacity, Mbpd	Net Capacity, Mbpd
Mt. Belvieu	75	305	253
Shoup and Armstrong	100	97	97
Hobbs	100	75	75
Promix	50	145	73
Norco	100	75	75
BRF	32.2	60	19
Tebone	52.5	30	12
Other (six)	100	12	12
Total Capacity		802	619

Figure A-4. DCP Midstream mixed NGLs (Rextag Strategies, 2012).

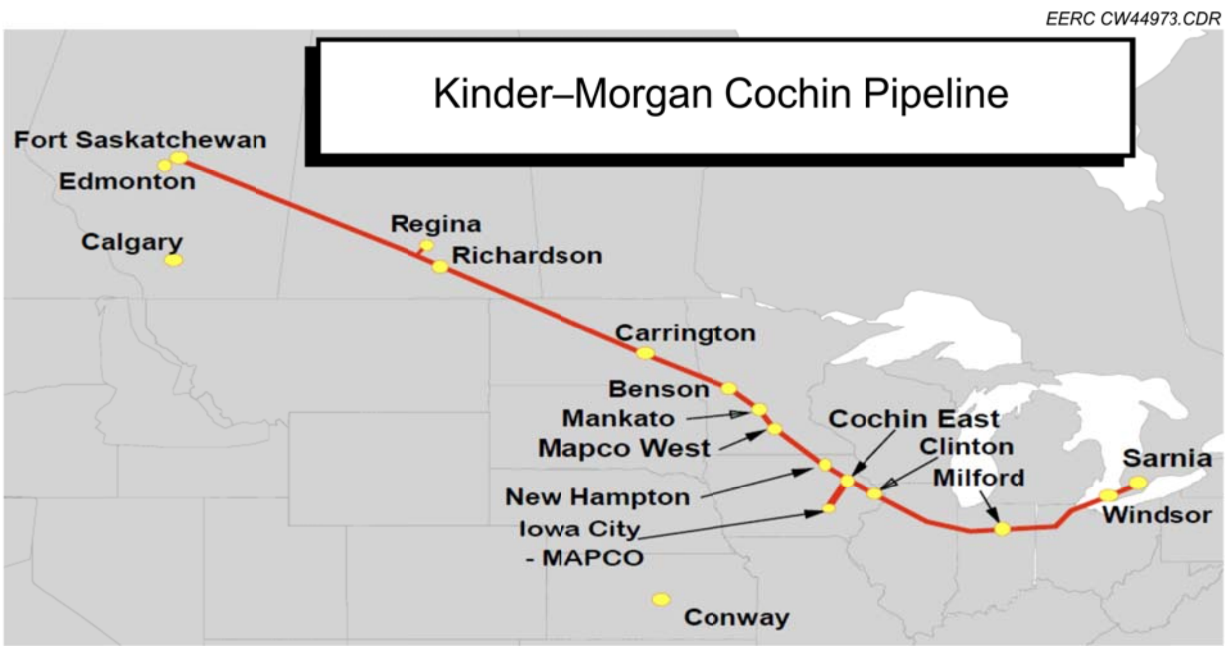

Figure A-5. Kinder–Morgan Cochin Pipeline map (Kinder–Morgan, 2010).

estimated capacity of about 70,000 barrels per day and has five U.S. propane terminals. In 2007, the pipeline had filed tariff agreements with Federal Energy Regulatory Commission C for the following products between the indicated points:

- Light hydrocarbon liquids between Fort Saskatchewan, Alberta, and Windsor, Ontario
- Ethane and ethane–propane mix between points in Iowa and in Michigan
- NGLs between Maxbass, North Dakota, and Detroit, Michigan
- Ethylene between Maxbass, North Dakota, and delivery points in Iowa and Michigan
- Ethane and propane between Cochin East, Iowa, and MAPCO near Iowa City, Iowa
- NGLs between Maxbass, North Dakota, and Detroit, Michigan
- Propane between points in North Dakota, Minnesota, and Iowa, and delivery points in North Dakota, Minnesota, Iowa, Indiana, and Michigan
- Ethane between Maxbass, North Dakota, and delivery points in Iowa and Michigan
- Field-grade butane between Maxbass, North Dakota, and Detroit, Michigan (reference to Maxbass and Detroit refers to the international boundary near those locations).

Currently, pipeline operations only involve propane. In June 2010, Kinder–Morgan announced a nonbinding open season to add a lateral segment to Clarington, Ohio, to transport Marcellus Shale Y-grade NGLs. Enterprise Products, Phillips 66, the Cochin (Dome) pipelines, and the Buckeye NGL pipeline (Figure A-6) comprise the majority of U.S. mixed NGL pipelines.

As shown in Figure A-7, Dow Chemical Company operates 3000 miles of product pipelines along the USGC. This system transports both liquid and gas products, with the vast majority of products being hydrocarbons that include NG, ethylene, propylene, propane, ethane, and ethane–propane mix.

Future Expansion Infrastructure

In response to recent market conditions, U.S. petrochemical companies are moving forward on expanding ethane-cracking capacity in the United States. The shale boom in North America has reversed the course of petrochemical companies which are switching feeds from naphtha to NGLs, unshuttering dormant facilities, modifying naphtha crackers to accept NGLs, and studying—if not beginning front-end engineering design of—new, multibillion-dollar complexes. In November, 2011, Bentek estimated that overall in the United States, the 17 fractionation addition and expansion projects that have been announced will increase fractionation capacity by 27% (835 Mbpd) by the end of 2016. This forecast likely did not

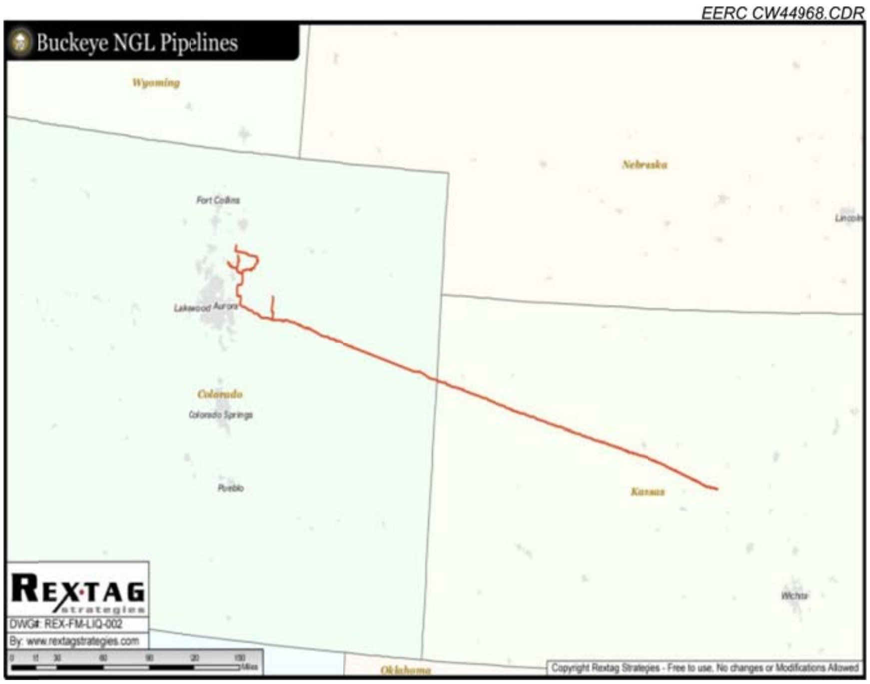

Figure A-6. Buckeye Mixed NGL Pipeline Route (Rextag Strategies, 2012).

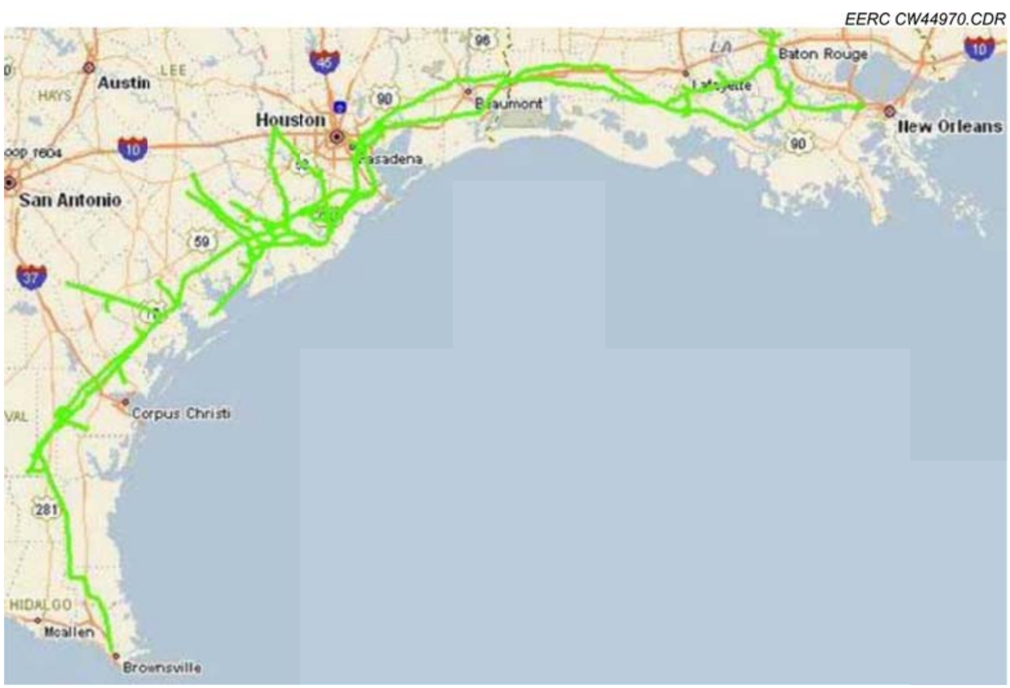

Figure A-7. Dow Gulf Coast pipeline system transporting hydrocarbon products to support Dow's feedstocks and olefins businesses (Dow, 2012).

include MarkWest Energy Partners' February 2012 announcement of 140 Mbpd of additional fractionation in the Marcellus region. Additionally, Bentek reported that 12 new and expanded NGL pipelines will add 1800 Mbpd of capacity through 2014. Two expansions transport NGLs to the Conway area, while the remainder move NGLs to Mt. Belvieu.

During the period 2011–2017, Williams estimates Marcellus production of ethane, propane, butanes, and NG will increase more than 185, 70, 30, and 20 Mbpd, respectively. For its size, the Marcellus is particularly underdeveloped: lacking processing, pipelines, fractionation, and other infrastructure. In response, Caiman Energy has announced projects in two locations that will install 720 MMcfd of gas-processing and 42.5 Mbpd of fractionation capacity within the next few years, and MarkWest is adding 1100 MMcfd gas-processing and 115 Mbpd of deethanizing fractionation capacity.

In North Dakota infrastructure expansion includes the Vantage ethane pipeline to Alberta and a rich gas line from the Tioga gas-processing plant to the Alliance Pipeline, which will permit some NGLs to travel with NG to fractionators in Illinois. Purvin & Gertz, the North Dakota Department of Mineral Resources and Vantage have projected North Dakota ethane supply to peak in the 2014–2020 time frame between 40 and 115 Mbpd, so the pipeline was designed to transport 40 Mbpd (60 Mbpd with additional pumping) of ethane to Alberta. Toll charges for the approximately 430-mile trip from Tioga, North Dakota, to Empress, Alberta, are to be 8.68 cpg the first year. OneOK's 60 Mbpd (110 Mbpd with additional pumping) Bakken Extension to the Overland Pass Pipeline that goes south from North Dakota to Bushton (KS), near Conway, relies upon the expansion of Kansas fractionators and pipelines to Mt. Belvieu to minimize the Kansas and North Dakota discounts.

In Kansas, ONEOK is increasing fractionation capacity in Bushton to match the additional 60 Mbpd to be received on the Overland Pass Pipeline.

Figure A-8 displays existing pipelines and summarizes expansions announced prior to September 2011.

Figure A-9 indicates that Mt. Belvieu, for example, will need to more than double its 2009 fractionation capacity to be able to fractionate its additional NGL imports.

Five world-class plants are planned or are being constructed in the United States:

- ChevronPhillips Chemical Company 1.5-million-tpy cracker outside of Houston and polyethylene plant near its Sweeny, Texas, cracker

- Dow Chemical ethylene and 0.75-million-tpy propylene units in Freeport, Texas

- Sasol 1.4-million-tpy cracker in Lake Charles, Louisiana

- Formosa Plastics 0.8-million-tpy ethylene cracker, 0.6-million-tpy propane dehydrogenation unit, and a linear low-density polyethylene plant in Point Comfort, Texas

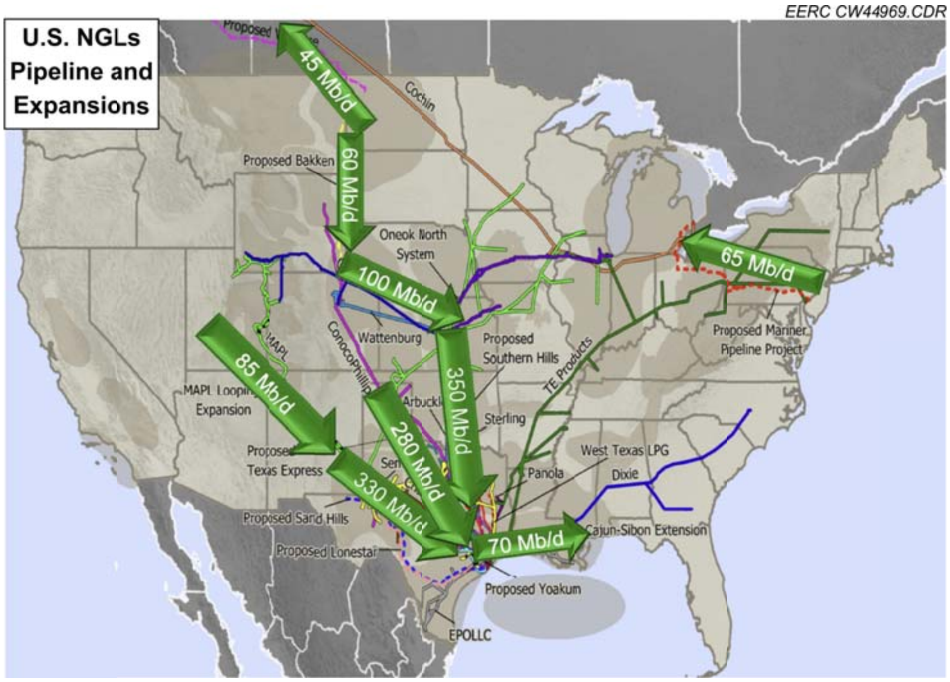

Figure A-8. U.S. NGL pipelines and expansions (Braziel, 2011).

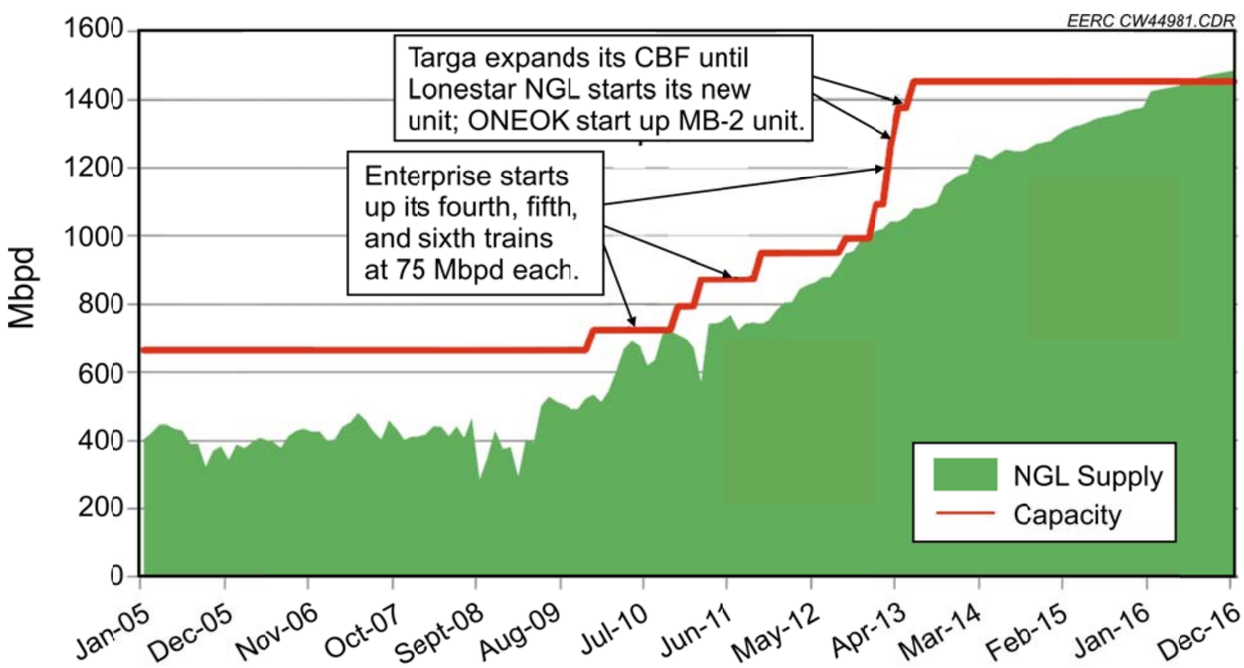

Figure A-9. NGL supply and fractionation capacity at Mt. Belvieu (Braziel, 2011).

- Shell ethane cracker, as well as polyethylene and monoethylene glycol chemical facilities in near Monaca, Pennsylvania

In addition to these, other companies are unshuttering or have suggested constructing or expanding cracking facilities:

- Dow is restarting a cracker near Hahnville, Louisiana.
- Occidental Petroleum in Ingleside, Texas, where it makes vinyl chloride.
- Either Chemicals is considering building an ethane catalytic cracker near Charleston, West Virginia.
- LyondellBasell is studying expansion equivalent to a half-cracker at an existing facility.

In reflecting on these announcements, industry and media have commented that not all announced facilities will be constructed and not in the announced time frames. The petrochemical industry has tended to overconstruct, resulting in excess capacity, and has viewed shale skeptically (although developing confidence with time). While most capacity should be installed in the 2015–2017 time frame, construction pace might be adjusted with infrastructure rollout and feed availability.

Shell's Appalachian facility, constructed away from the USGC infrastructure, has drawn attention. Factors favoring the plan include:

- Proximity to the Marcellus supply.
- Location within 400 miles of almost half of U.S. plastics converters who would benefit by having faster delivery and less inventory requirements.
- Lower ethane feedstock cost because of lack of infrastructure to transport ethane out of the region.
- Potential underground ethane storage (as indicated by the presence of underground NG storage in the Appalachian region shown in Figure A-10).

Factors that could work against Shell's proposal include:

- Lack of infrastructure (although Shell representatives have said that there is a solution to the lack of infrastructure issue).
- Lower feedstock price, which will be temporary as infrastructure appears.

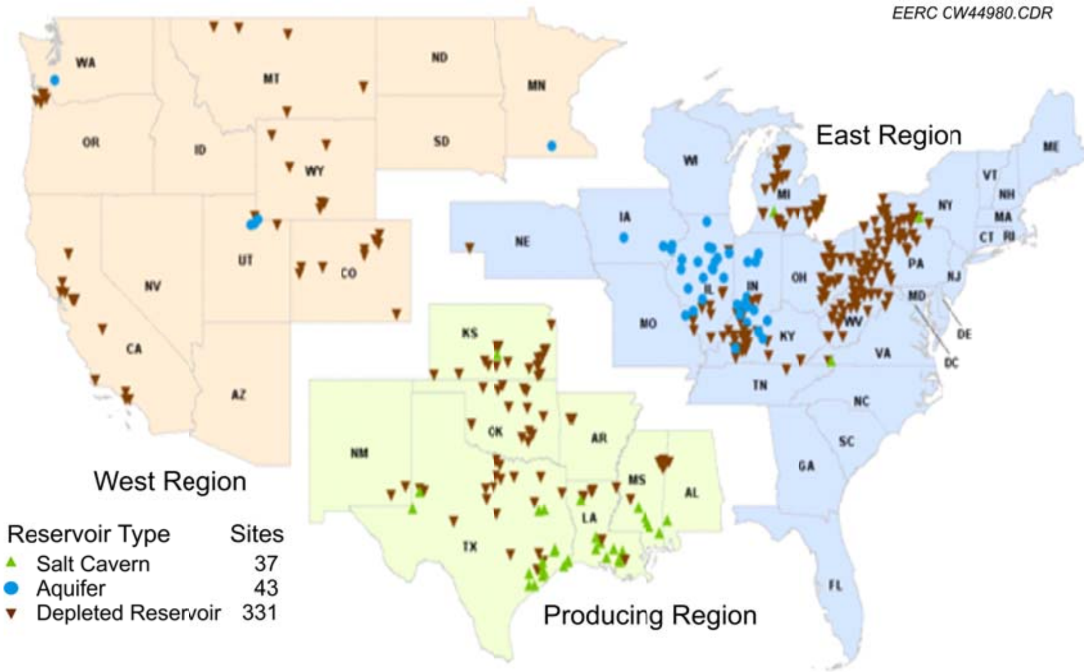

Figure A-10. U.S. lower 48 states' underground gas storage facilities, December 31, 2010 (U.S. EIA).

- The requirement to build local polyethylene plants to take advantage of local polyethylene market (i.e., converters).

The most recurrent question at conferences appears to be feedstock disposition when the cracker goes down: without another cracker in the region and without ethane storage, since suppliers will continue to produce ethane, where will feedstock be diverted to? A common comment by the media is that one cracker begs construction of a second.

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APPENDIX B

DISTRIBUTED-SCALE AMMONIA PLANT PRELIMINARY DESIGN

DISTRIBUTED-SCALE AMMONIA PLANT PRELIMINARY DESIGN

DESIGN APPROACH

As part of a project to develop a basic engineering design package for a 20-ton/day ammonia production plant based on the use of natural gas feedstock, the Energy & Environmental Research Center developed a preliminary plant design comprising the primary unit operations (unit ops) of:

- Feedstock gas cleanup to the extent required to yield a methane-rich gas suitable to undergo catalytic steam reforming.
- Catalytic steam reforming of methane-rich gas to yield a syngas comprising primarily hydrogen, carbon monoxide, carbon dioxide, and water, followed by hydrogen separation from the syngas to yield a hydrogen stream with a purity level of at least 99.99%.
- Separation of nitrogen from air to yield a nitrogen stream with a purity level of at least 99.99%.
- Ammonia synthesis via reacting high-purity hydrogen with air-extracted nitrogen in a reactor system equipped with capabilities for ammonia recovery, recycle of unreacted hydrogen and nitrogen, and purge of inert materials.

This design was the basis for ammonia production cost estimates presented previously. Following is a description of the ammonia process, after which tables containing individual equipment costs and tables containing detailed product cost breakdowns appear.

Figure B-1 illustrates the ammonia production pathway and key process inputs, along with optional modules for on-site electricity production and conversion of ammonia to urea. The overall natural gas-to-ammonia process was conceptualized and simulated with Aspen Plus modeling software. The simulation encompassed separation of raw gas-contained methane from impurities such as sulfur compounds and carbon dioxide, reforming methane into hydrogen, nitrogen separation from air, and reaction of hydrogen and nitrogen to form ammonia. The basic process flow diagram developed from the Aspen Plus model is shown in Figure B-2. The model was optimized based on an input of 39,000 standard cubic feet/hour (scfh) of raw gas with a composition of 52% methane, 36% carbon dioxide, and the remainder being nitrogen, oxygen, and trace amounts of sulfur compounds. About 350 gallons/hour of water is consumed during hydrogen production, and 120,000 scfh of air is required for combustion (to provide heat to drive the endothermic steam methane reforming [SMR] hydrogen production reaction) and as a source of nitrogen. Approximately 1 megawatt (MW) of electricity is required, most of which is used for gas compression.

To enable the quickest path to plant fabrication, the basic engineering plant design effort incorporated—to the extent possible—commercially available technologies as primary unit ops.

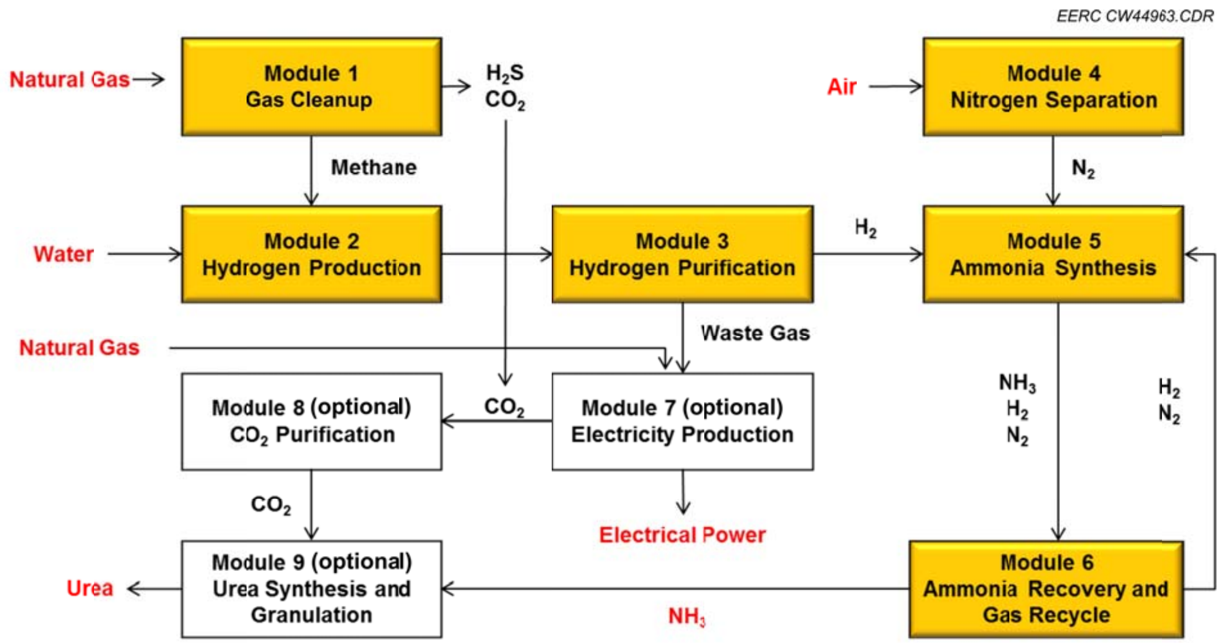

Figure B-1. 20-ton/day ammonia production plant working block flow diagram.

Based on input and output requirements for a 20-ton/day ammonia plant, quote requests were prepared and let for supplying technologies for 1) gas cleanup, 2) hydrogen production and purification, 3) nitrogen separation from air, and 4) ammonia synthesis—including ammonia recovery, recycle of unreacted hydrogen and nitrogen, and purge of inert materials. Viable quotes from qualified vendors were received for supplying gas cleanup, hydrogen production and purification, and nitrogen generation units. Because no viable quotes were received for supplying an appropriately sized ammonia synthesis unit, a bid solicitation was prepared and let for preparation of a basic engineering design package for the unit. Two viable bids from qualified vendors were received in response to the bid request. After reviewing all received quotes and bids, preferred vendors were contacted to confirm quoted prices, performance representations, and delivery dates, and the technologies/vendors to be utilized in the ammonia plant design were selected. Descriptions of the selected technologies are provided as follows.

Gas Cleanup

Gas cleanup in the form of sulfur and carbon dioxide removal is required to ensure against sulfur contamination of the SMR catalyst and ensure to maximum-efficiency SMR performance. The selected gas cleanup technology utilizes a pressure-swing adsorption (PSA) process for carbon dioxide separation and a solid sorbent bed for removal of sulfur impurities. Prior to these operations, the raw gas is compressed and dried. The gas cleanup technology delivers approximately 86% of the raw gas-contained methane at a purity level of 96% or greater, which equates to approximately 775 pounds/hour of methane sent to the SMR (hydrogen production) unit operation. The residual methane (along with a large volume of carbon dioxide) is also routed to the SMR unit to be combusted for heat. About 202 kW of electricity is required for gas compression.

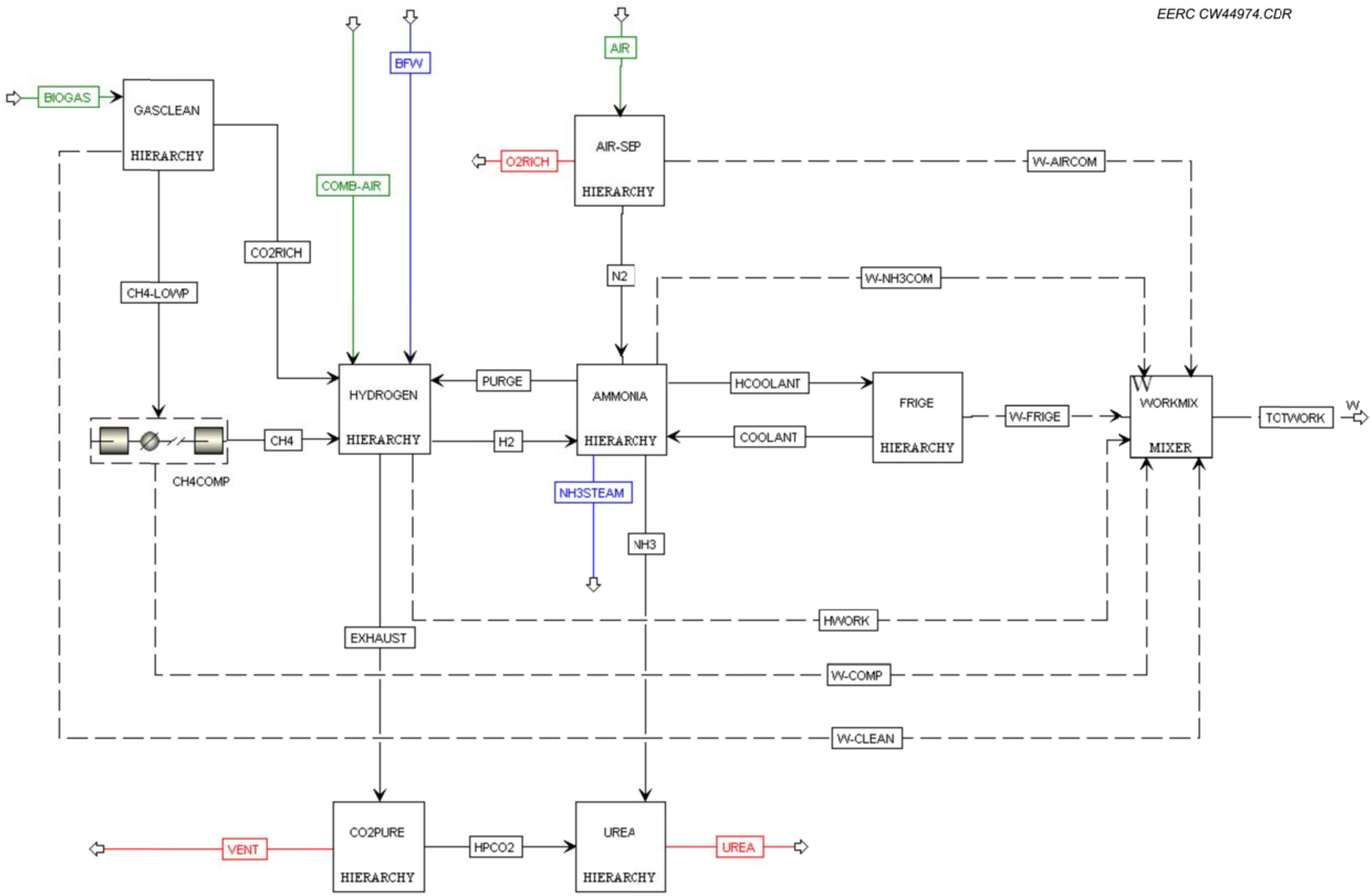

Figure B-2. Aspen Plus-developed basic process flow diagram for 20-ton/day ammonia (35-ton/day urea) production plant.

Hydrogen Production and Purification

The hydrogen production module converts methane into hydrogen via SMR. A portion of the methane feed stream is used for combustion to provide heat for the SMR process. The rest of the methane is converted to hydrogen and carbon monoxide in the first reactor. A subsequent water–gas shift reactor converts the carbon monoxide into more hydrogen. Two PSA units are used to separate the hydrogen from the waste gas. About 296 lb/hour of hydrogen (with a purity level of 99.99%) is produced from the 775 lb/hour of methane fed to the SMR unit. About 556 lb/hour of water is required for the steam-reforming process, and 6360 lb /hour of air is required for combustion. Figure B-3 shows an SMR unit comparable in capacity to that required for supplying hydrogen to a 20-ton/day ammonia plant.

Nitrogen Generation

Nitrogen is extracted from air using a PSA unit. The selected PSA system generates about 1373 lb/hour of nitrogen at a purity level of 99.96%. About 235 kW of electricity is required for air compression.

Ammonia Synthesis

The high-purity hydrogen and nitrogen outputs from the SMR and nitrogen PSA units, respectively, are sent to an ammonia synthesis reactor system currently being designed by a vendor with significant experience in designing large-scale commercial ammonia production plants. The model shown in Figure B-4 is the basis for the design effort. The hydrogen and

Figure B-3. Approximate 300-lb/hour SMR hydrogen production–purification unit.

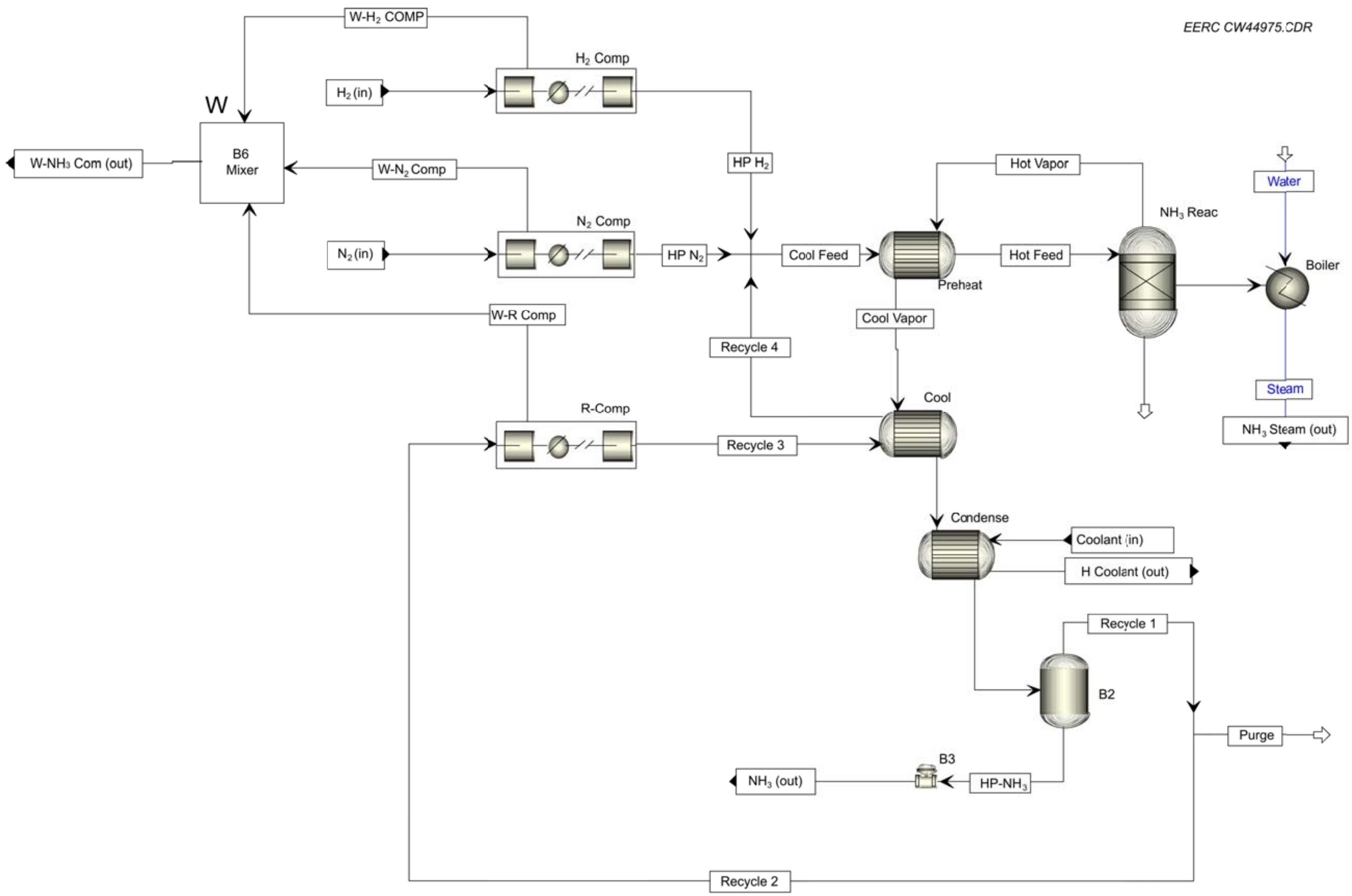

Figure B-4. Aspen Plus model of ammonia synthesis unit operation.

nitrogen streams will undergo compression to approximately 100 bar and then will be combined in a catalytic ammonia reactor. The produced ammonia will be condensed and separated from the unconverted gases, which are recycled back to the reactor. Near 100% conversion of hydrogen and nitrogen is achieved and 1710 lb/hour (equating to about 20 tons per day) of ammonia is produced. About 304 kW of electricity is required for gas compression. The ammonia product can be stored for sale or converted to urea. For urea production, exhaust carbon dioxide from the SMR (hydrogen production) unit is purified and reacted with ammonia to produce urea. About 2089 lb/hour of carbon dioxide is required to react with the 1710 lb/hour of ammonia to yield 2850 lb/hour (equating to about 35 tons/day) of urea.

Capital Cost Estimate

Using the quotes received from vendors for selected unit operations and smaller equipment pieces and ancillary plant requirements, a cost estimate for fabrication of a 20-ton/day natural gas-to-ammonia plant was prepared. As shown in Table B-1, the total estimated capital cost of the plant is $16.5 million. Also as shown in the table, the total cost estimate includes a $2.5 million used hydrogen production unit. The unit comes with a guarantee, and it is worthwhile to note that several small-scale good-condition SMR units are available from vegetable oil refiners that are facing reduced demand for hydrogenated vegetable oil and no longer need on-site hydrogen production capability.

Using this 20-ton/day design and cost estimate as the basis, an analysis was performed to evaluate the economics of ammonia production for three scenarios:

Table B-1. 20-tons/day Ammonia Plant Preliminary Capital Cost Estimate

Cost Item	Cost Estimate, $million	Notes
Gas Cleanup	3.6[1]	Includes $500K assembly cost
Hydrogen Production/Purification	2.5[2]	Used unit; includes $500K assembly cost
Reverse Osmosis Water Cleanup	0.1	
Nitrogen Generation	1.4	Includes $300K assembly cost
Ammonia Synthesis Loop	2.5	Preliminary cost estimate
Hydrogen Compressor	1.5	
Nitrogen Compressor	0.5	
Control System	0.1	
Ammonia Storage[3] and Loadout	1.1	
Detailed Engineering	1.3	
Site Preparation	0.5	Estimate; need site-specific information
Assembly	0.5	
Shakedown	0.5	
Total Installed Cost	**16.5**	

[1] Less expensive unit may be available.
[2] Cost of new unit, including assembly, is $6 million.
[3] 7 days worth (140 tons) of storage.

- 2000 Mcfd gas flow and a 2000-Mcfd-capacity reactor (90 tpd ammonia)
- 320 Mcfd gas flow and a 2000-Mcfd-capacity reactor (90 tpd ammonia)
- 320 Mcfg gas flow and a 320-Mcfd-capacity reactor (15 tpd ammonia)

In the absence of an objective basis by which to estimate siting requirements for a compact ammonia production unit, no land acquisition costs were incurred in this cost estimate.

A total capital equipment cost of $6 million was used for the 20-tpd system. Cost estimates for the different-sized systems was accomplished by means of correlations using the exponential relationship between equipment size and cost:

$$Cost_2 = Cost_1 * (Size_2 / Size_1)^n$$

Standard exponents from the technical literature (Towler and Sinnott, 1991) were adopted, and a 0.79 exponent was adopted based on literature values.

Detailed economic data for each of the three scenarios is provided in Tables B-2–B-4.

Table B-2. 2000 Mcfd and Large Reactor Design Applying Current Technology Reformer

Ammonia Total Product Cost Estimate

2000 Mcfd and Large Reactor Design

		Feed Rate: 2000 Mcfd natural gas
Location:	Bakken (2012)	Heating value: 1490 Btu/cf natural gas
Capital Investment		Gas Consumption: 36.5 MMBtu/tonne
Fixed	$51,889,617	Capacity: 81.7 tonne/d ammonia
Working		90.1 ton/d ammonia
Start-Up	$500,000	On Stream: 95%
Total	$52,389,617	Production: 31,249 ton/year ammonia

	Quantity/ton	Price $/unit	Cost $/year	Cost $/ton
Raw Materials				
Natural Gas (Feed + Fuel)	22.2 Mcf	0.00	0	0.00
Utilities				
Electricity	1200 kWh	0.09	3,374,889	108.00
Water	420 gal	0.02	262,491	8.40
Total Utilities			3,637,380	116.40
Labor				
Operating	0.25 Operator/shift	300,000	75,000	2.40
Laboratory	10% Operating labor		7500	0.24
Maintenance	1.5% Fixed captial Investment (FCI)		778,344	24.91
Operating Supplies	10% Operating labor		7500	0.24
Supplies				
General	0.6% FCI		311,338	9.96
Maintenance	1.5% FCI		778,344	24.91
Catalyst and Chem.			31,250	1.00
Direct Production Cost				180.06
Plant Overhead	20% Total labor		173,669	5.56
Fixed Charges				
Insur. and Taxes	2% FCI		1,037,792	33.21
Depreciation	5% FCI + start-up		2,619,481	83.83
Manufacturing Cost			9,457,598	302.65
Gen. Expen. (Salary Administration Research and Expenses (SARE)	1% Sales		95,531	3.06
Total Product Cost				305.71
Before Tax Return on Investment (ROI)	0% Total investment		0	0.00
Product Value			9,553,130	305.71

Table B-3. 320 Mcfd and Large Reactor Design Applying Current Technology Reformer

Ammonia Total Product Cost Estimate				
320 Mcfd and Large Reactor Design				
			Feed Rate: 2000 Mcfd natural gas	
Location:	Bakken (2012)		Heating value: 1490 Btu/cf natural gas	
Capital Investment			Gas Consumption: 36.5 MMBtu/tonne	
Fixed	$51,889,617		Capacity: 81.7 tonne/d ammonia	
Working			90.1 ton/d ammonia	
Start-Up	$500,000		On stream: 95%	
Total	$52,389,617		Production: 31,249 ton/year ammonia	

	Quantity/ton	Price $/unit	Cost $/year	Cost $/ton
Raw Materials				
Natural Gas (Feed + Fuel)	22.2 Mcf	0.00	0	0.00
Utilities				
Electricity	1200 kWh	0.09	539,613	108.00
Water	420 gal	0.02	41,970	8.40
Total Utilities			581,583	116.40
Labor				
Operating	0.25 Operator/shift	300,000	75,000	15.01
Laboratory	10% Operating labor		7500	1.50
Maintenance	1.5% FCI		778,344	155.78
Operating Supplies	10% Operating labor		7500	1.50
Supplies				
General	0.6% FCI		311,338	62.31
Maintenance	1.5% FCI		778,344	155.78
Catalyst and Chem.			5000	1.00
Direct Production Cost				509.29
Plant Overhead	20% Total labor		173,669	34.76
Fixed Charges				
Insur. and Taxes	2% FCI		1,037,792	207.71
Depreciation	5% FCI + start-up		2,619,481	524.27
Manufacturing Cost			6,375,551	1,276.03
Gen. Expen. (SARE)	1% Sales		64,400	12.89
Total Product Cost				1288.91
Before Tax ROI	0% Total investment		0	0.00
Product Value			6,439,950	1288.91

Table B-4. 2000 Mcfd and Small Reactor Design Applying Current Technology Reformer

Ammonia Total Product Cost Estimate

320 Mcfd and Small Reactor Design

			Feed Rate: 320 Mcfd natural gas
Location:	Bakken (2012)		Heating value: 1490 Btu/cf natural gas
Capital Investment			Gas Consumption: 36.5 MMBtu/tonne
Fixed	$16,885,099		Capacity: 13.1 tonne/d ammonia
Working			14.4 ton/d ammonia
Start Up	$500,000		On stream: 95%
Total	$17,385,099		Production: 4996 ton/year ammonia

			Cost	
	Quantity/ton	Price $/unit	$/year	$/ton
Raw Materials				
Natural Gas (Feed + Fuel)	22.2 Mcf	0.00	0	0.00
Utilities				
Electricity	1200 kWh	0.09	539,611	108.00
Water	420 gal	0.02	41,970	8.40
Total Utilities			581,581	116.40
Labor				
Operating	0.25 Operator/shift	300,000	75,000	15.01
Laboratory	10% Operating labor		7500	1.50
Maintenance	1.5% FCI		223,276	50.69
Operating Supplies	10% Operating labor		7500	1.50
Supplies				
General	0.6% FCI		101,311	20.28
Maintenance	1.5% FCI		253,276	50.69
Catalyst and Chem.			5000	1.00
Direct Production Cost				257.07
Plant Overhead	20% Total labor		68,655	13.74
Fixed Charges				
Insur. and Taxes	2% FCI		337,702	67.59
Depreciation	5% FCI + start-up		869,255	173.98
Manufacturing Cost			2,560,056	512.38
Gen. Expen. (SARE)	1% Sales		25,859	5.18
Total Product Cost				517.56
Before Tax ROI	0% Total investment		0	0.00
Product Value			2,585,916	517.56

REFERENCES

Towler, G.; Sinnott, R. *Chemical Engineering Design: Principles, Practice and Economics of Plant and Process Design* second edition; Elsevier Ltd.

Peters, M.; and Timmerhaus, K. *Plant Design and Economics for Chemical Engineers*; fourth edition, McGraw-Hill, Inc., 1991.