CARBON LIMITS

Improving utilization of associated gas in US tight oil fields

Appendix 1-4

This report was prepared by Carbon Limits AS.

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Improving utilization of associated gas in US tight oil fields

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Carbon Limits is a consulting company with long standing experience in supporting energy efficiency measures in the petroleum industry. In particular, our team works in close collaboration with industries, government, and public bodies to identify and address inefficiencies in the use of natural gas and through this achieve reductions in greenhouse gas emissions and other air pollutants.

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Appendix 1: Overview Tables for Technologies that Pass Screening

1.1 Gas Gathering

Factors			Data	Comments ↑ Advantage ↨ barrier
TECHNICAL	Equipment	*text*	Gas gathering lines regulated under 49 CFR Part 192 Compressors and auxiliary equipment	
	Tech.maturity	*text*	Proven extensively internationally, including tight oil and shale gas High Btu, liquid rich gas may present issues if it is not an NGL pipeline	
	Reliability	*text*	Pipelines are suffering an increasing number of reliability issues related to NGL pooling, older wells knock off the gathering systems and tight gas gathering and processing capacity	
	Pressure and Temperature	*Psig* *F*	20-25 psi suction pressure	Proven for high and low pressure Can handle pressure from the separator
	Volume range	*Mcf per day*	0 -	Can handle most volumes given appropriate pressure
	Scaling up/down	*text*	Expensive to scale up and not possible to scale down	
	C3+ content	*text*	Pipeline can in principle accept high Btu gas[1], but extra rich streams (> 1600 Btu / scf) should go through a simple refrigeration / compression to drop out heavier liquids. Anyhow, Rich gas might generate issues especially during winter months	
	Impurities and other components	*text*	Gas gathering lines may not impose very stringent requirements to associated gas, depending on the gas gathering company, on the other hand, interstate pipelines do have much stricter requirements for impurities[2]	
	CO_2 Emission Reduction	*%*	85 - 100	at the flare, estimations depending on pipeline utilization, flow back and safety flaring
	VOC Emission reduction	*%*	85 - 100	
GEOGRAPHICAL	Integration with other wells	*text*	It is only beneficial if the O&G operators are the developers of the gas gathering systems, or the gas processing plants reflects the lower cost of that development	
	Mobility / Deployment	*text*	It is not a portable technology. Pipeline development is very slow. Pipeline permitting alone does not secure the necessary rights of way needed by producers from landowners to build gathering pipelines from the wellhead. Pipeline would require dismantling at the end of the lifetime/project.	
COMMERCIAL	Business models	*text*	Mid-stream contractual agreements include In-kind fee and fixed price, which are easier to manage by the O&G operator. New pipelines remove some of the trucks operations and HSE issues (road accidents) compared to trucking NGL, CNG and LNG.	
	Procurement	*text*	Months / years	Permitting and regulatory processes are not streamline and there is a lag between permit approval and construction completion
	Capital exp.	*USD / Mcf per day*	100 - 300	Multimillionaire investments are very attractive at per well cost. Single well integration highly dependent on distance
		000 USD / mi	100 - 700	
	Operational exp.	*USD / Mcf*	0.05 - 1	Low operating cost, but compression and dehydration to meet gas gathering pipeline specifications can go up to 0.65-1 USD / Mcf and Broker Fees, Transport Fees, Line Loss up to 0.5 USD / Mcf
	Revenue	*USD / Mcf*	Net Price to Producer ~ 2, even when the gas price ~ 3 - 4	Midstream contractual agreement are usually beneficial to gas processing plants, and O&G operators are not getting premium for NGL. Pipeline capacity may get tight in the upcoming years if pace of development continues and gas utilization increases. Profitability highly depends on the volumes and contracts.
	Pay-back time	*years*	< 1 year	

[1] *Bakken energy content is 1 200 – 1 700 Btu / ft^3. Eagle ford is leaner. Alliance Canada (FERC-certified high pressure rich gas pipeline): Heating value 36MJ / m^3<HV<60MJ / m^3, which makes the upper threshold ~ 57 000 Btu / ~ 35 ft^3 = ~ 1 600 Btu / ft^3. Northern Border: Heating value > 967 Btu / ft3. No limit for rich components.*

[2] *Northern Border: Sulfur: 2grains / Ccf3 , O_2 Max: 0.4%, CO_2 Max: 2%, Water Max: 4 lbs / MMcf .Alliance Canada (FERC-certified high pressure rich gas pipeline): Sulfur Max: 115 mg / m^3, O_2 Max: 0.4%, CO2 Max: 2%, Water Max: 65mg / m^3.*

1.2 CNG Trucking

Factors			Data	Comments ↑ Advantage ↨ barrier
TECHNICAL	Equipment	*text*	Multi-stage compressors, CNG hoses and CNG tube containers and trailer (~ 200 Mcf capacity)	
	Tech.maturity	*text*	The technology is mature as associated gas utilization option. Current operations in several tight oil fields	
	Reliability	*text*	98% availability	Linked to well reliability, since equipment has to start and stop
	Pressure and Temperature	*Psig* *F*	Compressor 15 psi min Truck 2 000 – 3 600 psi	Typical treater in oil field onshore production is 40 psi, so, in principle, this is not an issue.
	Volume range	*Mcf per day*	300 - 4 000	Performance depending on flow rate (peaks), sometimes flow rates are in excess of compression capacity, so oversizing may be required, lowering efficiency
	Scaling up/down	*text*	Scaling up is just limited by the amount on the road and efficiency it is limited to the largest CNG trucks available, currently around 200 mcd[3]. Equipment does not scale down well either	
	C3+ content	*text*	The technology handle any gas composition, since heavier liquids will drop out during multistage compression	
	Impurities and other components	*text*	H_2S removal and dehydration (< 0.5 lb/mMcf water) may be needed.	
	CO_2 Emission Reduction	*%*	75 - 90	Estimations, depending on the fuel consumption of the multistage compressors
	VOC Emission reduction	*%*	75 - 99	
GEOGRAPHICAL	Integration with other wells	*text*	Tested on 5 wells working together. If 1 in each place it makes it more difficult. Need at least 5 units to have economies of scale for mechanic, supervisor, supplies, materials etc. Shale plays are large and it becomes uneconomic to have manpower go 3 hours driving for 2 hours of working	
	Mobility / Deployment	*text*	Portable equipment delivering up to 50 miles radius / 1 day for deployment	
COMMERCIAL	Business models	*text*	Fee for service or monetization of products. Suppliers offer monthly rates, which cover equipment plus manpower. Large storage space and several trucking operations are required every day, increasing risk associated to transportation issues (weather, roads, etc.)	
	Procurement	*text*	Within weeks	Still unknown the chance of delivering massively
	Capital exp.	*USD/Mcf per day*	400 – 2 000	If all is purchased at once, compressors and trailers are the key items
	Operational exp.	*USD/Mcf*	0.24 – 1.3	Medium to high operational expenses, due to the leasing of the trucks and compression needs
	Revenue per year	*USD/Mcf*	5 - 6	Product is rich CNG product (requirement that it is in single phase, ISO standard) that can be used in large stationary engines or as raw material for gas processing plants. It cannot be sold directly as car engine fuel to CNG dispensers, since it does not meet specifications. Placing the product, and finding sweet price spots may be challenging. Profitability highly depends on the gas stream volumes Marketing of the rich CNG is a big challenge (as with any other product). Need to find an offtake and agree on commercial terms
	Pay-back time	*years*	~ 1	

[3] *One model available it is the Fiba canning (www.fibacanning.com) 10 tube 2850 / 3135 PSI 40» ABS skids (3T 36» tubes) that can carry 217 mscf of natural gas per travel. It is still recommended to call to discuss use of natural gas / methane in those tubes. Rawhide leasing (http://www.rawhideleasing.com/) does not offer any model matching 200 mscf load, but can build on demand.*

1.3 NGL Recovery

Factors			Data	Comments ↑ Advantages ↕ barrier
TECHNICAL	Equipment	*text*	(i) Skid-mounted, automatically-operated, Mechanical NGL (ii) Cryogenic JT NGL recovery unit For both options, storage tanks	
	Tech.maturity	*text*	Mature, including shale gas operations, but few deployed in tight oil operations	
	Reliability	*text*	98% uptime [4] High[5]	Little maintenance and PLC[6] available, 1 monthly check and oil change every 3 months. (ii) Technologies are prone to freeze-up from ice and hydrates[7], so dehydration or methanol atomization is needed
	Pressure and Temperature	*Psig* *F*	Ambient - 1000 -40 -20[8]	Broad range of pressure inlet
	Volume range	*Mcf per day*	100 - 1 500	Matching tight oil conditions
	Scaling up/down	*text*	Several options to run on parallel, and purchase/leasing alternatives. Scaling down may be difficult below 100-200 Mcf per day[9]	
	C3+ content	*text*	Can generally accommodate important variation in C3+ content. Ethane recovery must be through a (ii) cryogenic system[10], which it is more complex and costly.	
	Impurities and other components	*text*	< 0.5-1 mol% CO_2 <very low mol% H_2O < 4 ppm H_2S [11]	No general issues with CO_2. Dehydration is needed. Desulfurization may be needed
	CO_2 Emission Reduction	*%*	(i) 2-10 (ii) 5 - 20	Theoretically it can achieve large CO_2 reductions (up to 40%) at the flare (less streams with much lower carbon content in the waste gas)[12]. In practice reductions are lower due to the efficiency of the systems and the sizing of the equipment
	VOC Emission reduction	*%*	50 -99[13]	Most of the heavier components are not in the flare stream
GEOGRAPHICAL	Integration with other wells	*text*	Well concentration may improve economics if the NGL recovery unit is large or there is an optimized design strategy.	
	Mobility / Deployment	*text*	From 1 day to 2 weeks for re location of equipment. Appropriate for the fast drilling pace of tight oil developments.	
COMMERCIAL	Business models	*text*	Fee for service or direct monetization of products[14]. No need for field fractionation, can truck/pipe NGLs to market. Business model selected depends on where the company wants to set their upstream / downstream boundaries and the contractual aspects of each business deal	

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[4] *Natural GasStar Programme Salem Unit Casinghead gas project http://www.epa.gov/gasstar/documents/workshops/2012-annual-conf/finch.pdf*
[5] *Houston, Robert R. Huebel and Michael G. Malsam from Randall Gas Technologies, "Oil and gas journal. New NGL-recovery process provide viable alternative*
[6] *Program logic controllers allows automation of electromechanical processes even from remote locations.*
[7] *The use of additives, typically glycol, presents issues for production: First, the additive increases the operating cost due to the direct cost of the additive. Second, additives cause downstream processing problems, including foam formation. Third, the additives must be removed and reprocessed, thereby increasing the capital equipment cost of the process.*
[8] *Natural GasStar Programme Salem Unit Casinghead gas project http://www.epa.gov/gasstar/documents/workshops/2012-annual-conf/finch.pdf*
[9] *Source: Wellhead Energy systems.*
[10] *Gord Salahor, VP at Vantage pipeline, "EIA Virtual Workshop on Natural Gas Liquids: NGL Market Development Example*
[11] *Natural GasStar Programme Salem Unit Casinghead gas project http://www.epa.gov/gasstar/documents/workshops/2012-annual-conf/finch.pdf*
[12] *% of what was emitted due to gas flaring. Carbon Limits stoichiometric simulation, using associated gas with typical Bakken composition, compared to a separate lean gas stream going to flare. (i) assumes ethane rejection and half propane efficiency, rest of the components between 95-99% efficiency; (ii) assumes ethane and propane recovery efficiencies of 90% and 98% respectively. Variable waste stream output and declines, 65% lean gas from rich gas stream, ~6 - 12 gallons per mscf. Confirmed through interviews and ND pipeline authority studies on NGL recovery options.*
[13] *Interviews outcomes and Carbon Limits estimates. Depending on the NGL recovery efficiency and on the flare combustion efficiency. As gas flaring may not achieve 100% combustion efficiency, a share of the inlet gas is emitted. Flares can achieve less than 2% unburned hydrocarbon when properly sized, maintained and operated. On the other hand, poor design or poor maintenance can lead to more than 30% unburned hydrocarbons.*
[14] *Gord Salahor, VP at Vantage pipeline, "EIA Virtual Workshop on Natural Gas Liquids: NGL Market Development Example*

Procurement	*text*	15 - 24 weeks	Available for deployment between 15 - 24 weeks, while (i) may be less and (ii) may delay more.
Capital exp.	*USD/Mcf per day*	(i) 800 - 2 500 (ii) 2 500	(i) Low-medium capital investment, while (ii) can become a substantial investment [15]
Operational exp.	*USD/Mcf*	(i) 0 - 0.22 (ii) 0.22 - 0.68	(i) Low operational costs for automatically-operated NGL recovery unit. (ii) Methanol supplies, additives and NGL distribution can increase operational expenses.
Lean gas / Rich gas	*% volume*	(i) ~ 65 - 90 (ii) ~ 50 to 65	(i) Recovers an important part of the liquids (35%-50%), while (ii) recovers even a high percentage of the ethane
NGL availability	*Gallons /Mcf*	8-12[16]	Ethane part is not economically as attractive as C_3+ components
Revenue	*USD/Mcf*	8 - 12[17]	In terms of BOE, it may mean up to 20% uplift in the ratio production/reserves, especially due to ethane volumes[18]. Ethane it is not as attractive. Possible bottlenecking if NGLs recovery becomes widespread Annual revenue highly variable depending on gas composition and gas rates
Pay-back time	*years*	< 1 years	

[15] *Miniaturization of gas purification technologies yields worse economics compare to large scale plants, making equipment expensive for very low gas rates*
[16] *Literature review and Carbon Limits estimates*
[17] *1 USD per gallon of NGLs.*
[18] *Gord Salahor, VP at Vantage pipeline, "EIA Virtual Workshop on Natural Gas Liquids: NGL Market Development Example*

1.4 Gas to Power (local demand and exports to grid)

	Factors		Data	Comments ↑ Advantage ↕ barrier
TECHNICAL	Equipment	*text*	Generator (a) Gas powered Gen-set using lean gas (b) Gas powered Micro-turbine using lean gas (c) Multi-fuel gas turbine using raw gas (d) Bi-fuel reciprocating engine using up to 65% lean gas (substituting diesel) (e) Bi-fuel reciprocating engine using up to 50% raw gas (substituting diesel)	Output i) To the grid ii) To local loads on-site
	Tech.maturity	*text*	Power generation is a mature technology. Bi-fuel engines cannot work on 100% raw gas, multi-fuel gas turbines are not deployed for tight oil operations (except some drilling operations) and micro-turbines are not as mature as large industrial gas turbines	
	Reliability	*text*	~ 96 - 98%[19]	Few maintenance operations are needed. Altitude of operations and gas volume and pressure may reduce performance. Operations in winter can be improved by utilizing waste stream heat and operational routines
	Pressure and Temperature	*Psig* *F*	(a)(c) 100-500 psi (b) 1-100 psi (d) 1-65 psi	In general the inlet gas pressure and temperature are not an issue
	Volume range	*Mcf per day*	(a)(c) 1000 - (b) 50-100 (d) 100 - 1000	There is flexibility on choice: Standard gas turbines are more useful for several wells tie-in with a NGL recovery system. Reciprocating for a single well and micro-turbines for taking up the production valleys or post first year volumes at single wells
	Scaling up/down	*MW*	(a) 0.2 - 50 MW (b) 0.05 - 0.2 MW (d) 100 - 1000	Scaling up it is fairly easy, scaling down may imply move to other type of engines, like small reciprocating engines and micro-turbines
	C3+ content	*text*	Without NGL recovery, power options are limited to bi-fuel and multi-fuel diesel substitution.	
	Impurities and other components	*text*	Dehydration and desulfurization are usually needed	
	CO_2 Emission Reduction	*%*	~ 98 % (i) ~ 20 - 98 % (ii)	Taking into account diesel substitution, additional 25-30 % CO_2 emissions reduction can be achieved and additional VOCs emission reductions, depending on combustion efficiency. Local loads may only use 20-30% of the associated gas volumes available
	VOC Emission reduction	*%*	~ 98 % (i) ~ 20 - 98 % (ii)	
GEOGRAPHICAL	Integration with other wells	*text*	It is possible to integrate several well streams into one power system. This has a clear advantages, and it is a much stable gas input to the system, increasing combustion performance, emission reduction and power revenue.	
	Mobility / Deployment	*days*	1	These power systems are portable in skids and units are adapted to harsh climate conditions. A trailer can deliver a re-localization of the unit to a new well in short notice
COMMERCIAL	Business models	*text*	Direct purchase of power equipment and renting are both available, and leasing under availability. Decreases diesel consumption, leading to less supply management. It can integrate easily into cost saving initiatives. Maintenance and operations service is intensive. Entering electricity market may not interest management, and requires specific expertise	
	Procurement	*weeks*	15 - 36	Established international suppliers and new local companies creating a market, capable to deliver > 10 units in a single order. Delivery time can expand if equipment customization and gas samples are needed (> 1 year makes it normally unsuitable)
	Capital exp.	*USD / MWh*	(a) 350 - 1200 (d) (e) 700 - 800 (i) (d) (e) 200 - 300 (ii) (b) 3200 (i) (b) 1500 (ii)	Local loads supply becomes much more affordable since it does not require Balance of Plant. 1 MW or larger gas turbines are the best investment. Balance of Plant can become a significant cost for smaller units.

[19] *NETL, North Dakota Industrial Commission and EERC, "End-Use Technology Study – An assessment of alternative uses for associated gas*

		USD / Mcf per day	(a) 1 500 - 5 000 (d) (e) 6 000 - 7 000 (b) 8 000	
	Operational exp.	*Mill USD / y*	0.02 - 0.64	Operational expenses can become much higher for the case of bi-fuel reciprocating engines and multi-fuel engines not tested extensively.
		USD / Mcf	(a) 1.15 (d) (e) 0.55 - 1.29 (b) 1.68	
		%	10 - 20 %	
	Power generation	*MWh per day*	5 - 150	Utility companies or state agencies may promote gas to grid utilization. Electricity market integration may present similar challenges as renewable energy generation without gas buffering capabilities, not capturing demand
	Revenues	*USD / Mcf*	(a) 3.6 (d) (e) 4.5 - 5.4 (b) 6.7	Fuel savings due to diesel substitution are really significant. CERs are a possibility to enhance project profitability for grid integration. Profits highly variable depending on gas volumes, electricity agreements and diesel prices.
	Pay-back time	*years*	3-5 years (i) 10-12 months (ii)	

1.1 Mini-GTL MT

Factors			Data	Comments: ↑ Advantage ↕ barrier
TECHNICAL	Equipment	*text*	Conventional technology (catalytic syngas route) not considered due to high costs and larger scale. Main equipment of *GasTechno* technology: Buffering tower, multistage-compressor, non-catalytic partial oxidation unit.	
	Tech.maturity	*text*	Large scale methanol (1000-5000 tpd) for over 50 years, small scale demonstrated in pilot plants and ready for commercialization	
	Reliability	*text*	Very high, off-the-shelf equipment and no catalyst.	
	Pressure and Temperature	*Psig* *F*	300 - 1 200 psi	High pressures requires buffering tower Low pressure requires multistage feed gas compression
	Volume range	*Mcf per day*	1 000 -	Minimum would be 50 - 150 Mcf per day, but commercially viable 1 000 Mcf per day, and highly profitable > 3 000 Mcf per day
	Turndown ratio	*text*	Operates from x0.5 to x2 (recycling) design rate. The recycle rate optimizes the production vs. efficiency curve. Effect of improved process efficiency at lower feeds without changing equipment	
	C3+ content	*text*	Any amount of ethane. Buffering tower knockout C6+ and feed gas compression would probably drop off liquids as well.	
	Impurities and other components	*text*	GasTechno is not very sensitive to impurities, Up to 60% CO_2 , 25% N_2, 25% H_2S On-site oxygen supply (LOX) or VSA or VPSA for oxygen production For other GTL-FT processes, feed gas can only contain few ppm of H_2S, if not, pretreatment is needed.	
	CO_2 Emission Reduction	*%*	< 89 %	Pure CO_2 a secondary by-product, can be sold, converted to other products, re-injected or otherwise sequestered, eliminating 89% of the original CO_2 emissions. The remaining 11% is vented from the compressor, electrical and heat generating equipment needed to run the process
	VOC Emission reduction	*%*	100 %	Assuming no leaks and fugitive emissions upstream, all of the light gases will be destroyed in the reactors
GEOGRAPHICAL	Integration with other wells	*text*	Integration with other wells is needed to supply a stable feed of natural gas	
	Mobility / Deployment	*text*	Redeploy can be from 1 week (including re-starting up) to 90 days, depending on logistics availability	
COMMERCIAL	Business models	*text*	Sold as a project, operated by O&G operators with simple GUI (Start/Stop)	
	Procurement	*text*	Up to 12 months	Ordering several units do not impact the delivery time
	Capital exp.	*USD/Mcf per day*	3 000 - 15 000	Main capital expenses are related to the "cold box", engineering, controls and automation and compression units. If pretreatment, disposal well and electrical utilities are not in the wellpad already, cost will increase.
	Operational exp.	*USD/Mcf*	0.8 - 3.8	Operation (inc. Oxygen) and maintenance is the most important expense, while electricity consumption is also relevant. Transport cost are not included here since they can greatly vary.
	Revenue per year	*USD/Mcf*	15 - 17	If products are not standard they need to be delivered to a fractionation / separation processing unit, and cannot directly be placed in the commodity markets
	Pay-back time	*years*	1 - 4	For a larger development (3 000 Mcf per day) one year payback time, for a smaller unit (1 000 Mcf per day), it may take 3-4 years.

Appendix 2: Overview of Technologies that Do Not Pass Screening

The following paragraphs describes four technologies that have not been considered for the main analysis. The applicability of these technologies have been compared to the conditions in tight oil production (see main report section 4) and the main reason for rejection are briefly described.

2.1 Gas Reinjection

Reasons for Rejection:

- ❖ Tight oil wells do not overlap in scale or location with depleted oil fields or other potential reservoirs. As a result, there is very limited potential capacity suitable for gas re-injection at reasonable distance from current production areas.
- ❖ Gas re-injection in tight oil formation itself represents some important technical challenges due to the low permeability of the formation.
- ❖ Gas re-injection has yet not been demonstrated in tight oil plays

Description of Technology:

Gas re-injection is a common practice used to dispose of or sequester associated gas in an underground reservoir. It can be used as a form of storage that allows the gas to be produced for market at a later time. If gas is injected into a crude oil reservoir with the intention of increasing pressure within the reservoir and increasing oil production, it is classified as an Enhanced Oil Recovery (EOR) method.

In the case of tight oil developments, re-injecting gas into the same reservoir is unlikely to be technically and economically feasible, due to the much lower permeability of shale fields than in conventional oil fields[20,21], although CO_2 injection (e.g. from flared waste stream) for improved recovery in the Bakken is receiving interest[22] but it is not proven yet.

An alternative is the injection of raw associated gas into shallower formations (such as salt caverns, aquifers, depleted reservoirs, etc.) close to the tight oil fields. However, there are major limitations related to:

- Availability and distance: The re-injection site would need to be closer than a gas gathering pipeline for re-injection to be logical (unless EOR is a significant incentive for re-injection).
- Number of wells: This depends on the capacity of the receiving formation, but typically gas from several production wells can be injected into a single well.
- Capital cost: The cost of a new well or a well recompletion would typically cost a few hundred thousand dollars, with high variability depending on the design of any existing well, depth of formation, etc.
- Operating cost: Compressor operating costs for the injection of gas.
- Regulatory cost: If applicable regulations include characterization and monitoring requirements, this may involve significant extra costs.

“Each storage type has its own physical characteristics (porosity, permeability, retention capability) and economics (site preparation and maintenance costs, deliverability rates, and cycling capability), which govern its suitability to particular applications. Two of the most important characteristics of an underground storage reservoir are its capacity to hold natural gas for future use and the rate at which gas inventory can be withdrawn-its deliverability rate. Most existing gas storage in the United States is in depleted natural gas or oil fields. The principal owners/operators of underground storage facilities

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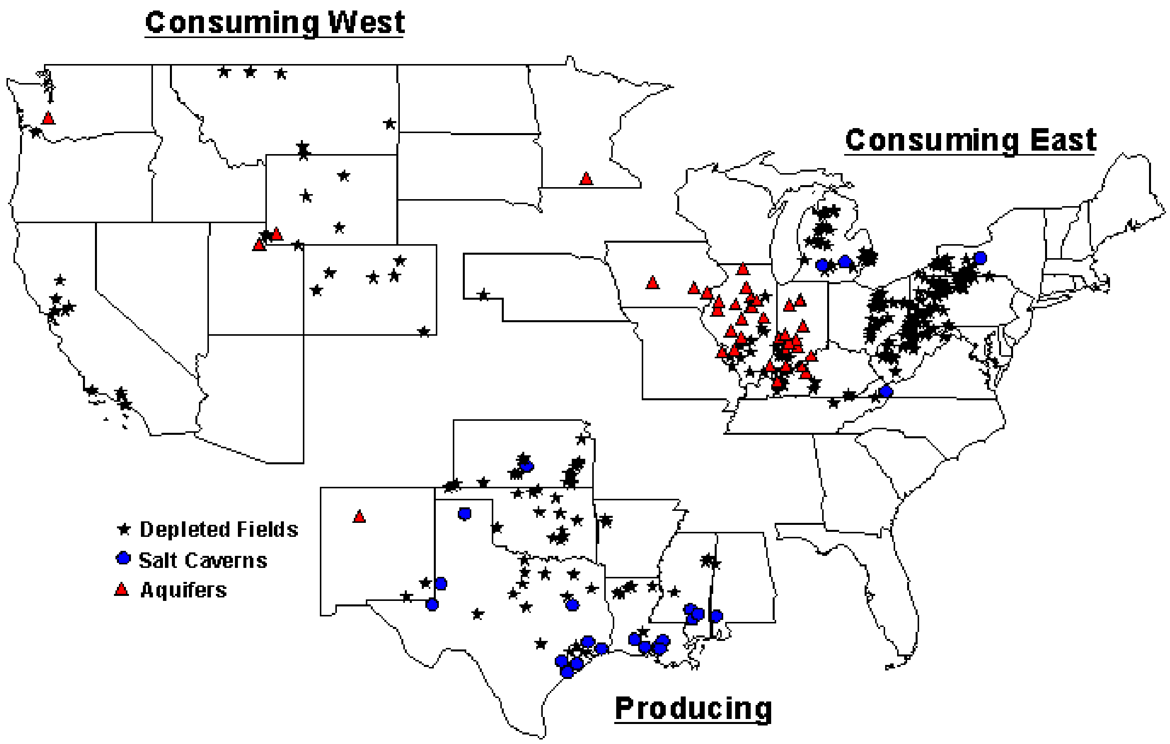
[20] http://www.midwestenergynews.com/2013/06/07/technological-limits-could-stifle-bakken-north-dakota-oil-potential/,” 07 06 2013. [Online]. Available: http://www.midwestenergynews.com/2013/06/07/technological-limits-could-stifle-bakken-north-dakota-oil-potential/
[21] M. J. A. A. D. f. Research, “http://www.undeerc.org/contactus/bios.aspx?id=1758,” http://www.undeerc.org, [Online]. Available: http://www.undeerc.org/contactus/bios.aspx?id=1758.
[22] C. Dong, “Master Thesis Colorado School of Mines: Modeling gas injection into shale oil reservoir of the Sanish Field, North Dakota”.

are (1) interstate pipeline companies, (2) intrastate pipeline companies, (3) local distribution companies (LDCs), and (4) independent storage service providers. There are about 120 entities that currently operate the nearly 400 active underground storage facilities in the lower 48 states. In turn, these operating entities are owned by, or are subsidiaries of, fewer than 80 corporate entities. If a storage facility serves interstate commerce, it is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC); otherwise, it is state-regulated. Owners/operators of storage facilities are not necessarily the owners of the gas held in storage. Indeed, most working gas held in storage facilities is held under lease with shippers, LDCs, or end users who own the gas"[23].

Figure 1: Underground Natural Gas Storage Facilities in the Lower 48 States. Source: Energy Information Administration (EIA), EIA GasTran Geographical Information System Underground Storage Database.



[23] *EIA, "The Basics of Underground Natural Gas Storage".*

2.2 Mini-LNG

Reasons for Rejection:

- Some suppliers are selling Mini-LNG plants to produce LNG from small sources of lean gas. However, the development it is still in early stage to accommodate associated gas.
- Pilot deployment on tight oil fields has not yet occurred.
- Portability is limited at present – Existing solutions are complex to set up.

Description of Technology:
In order to improve the transportability of natural gas, it can be condensed into liquefied natural gas (LNG), which takes up about 1/600th the volume of natural gas in its gaseous state. AG will require initial treatment to remove water, H_2S, CO_2, condensate, and other components that might freeze. The gas is cooled down through several stages, usually in a cryogenic cooling circuit and a main liquefier or "cold box", until it is liquefied (at approximately -162^{0}C). The process would also produce NGLs. The LNG is then routed to LNG storage tanks and then periodically shipped using suitable vessels or tanks. The density of the LNG makes it particularly useful for storing large amounts, and shipping very long distances, where it becomes cheaper than pipeline and CNG deliveries.

Traditional LNG plants are large (1-10 Million Metric Tonne Per Annum), complex and capital intensive projects that can take up to 72 months to complete[24]. Greenfield LNG liquefaction project cost has increased considerably in the latest years, from around 400 USD / tpa to 1000 USD / tpa for several reasons e.g. lack of skilled workforce and supplier availability, exotic locations and high raw material prices. Regarding operational cost, utilities and offsite facilities that are not part of LNG trains and processes utilities are key components, while up to 20-30% of the feed gas may be consumed due to NGL extraction or energy use for liquefaction and secondary processes like impurity removal[25].

In the last ten years, efforts have been also concentrated into the miniaturization of the LNG technology standardizing the technology so it is repeatable and scalable, with decreased cost. Considering that 1 tonne of LNG is ~ 50 Mcf[26] or ~ 600 LNG gallons[27], we could consider that the appropriate miniaturization for a plant to accommodate tight oil gas utilization conditions would be 5 - 50 LNG tonnes/day. More information can be found in the case studies in Appendix 3.

Best case scenario would be several very productive wells in a remote location with more upcoming wells that serves continuously a several one mini LNG with a processing capacity of at least 1 000 to 5 000 Mcf per day. I would require large storage space and hitting the LNG market in premium spots and locations.
Worst case scenario contemplates a lower than expected LNG price scenario and a company that has invested on an overdesigned unit, midstream delivery (trucking) of the products and with lack of operation and maintenance expertise on LNG.

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[24] *GE Oil and Gas, "Accelerating Adoption of LNG fuelling infrastructure," [Online].*
[25] *Expansion Energy, "http://www.expansion-energy.com/yahoo_site_admin/assets/docs/Expansion_Energy_LLC_-_VX_Cycle_Overview_PPT.295115525.pdf," [Online]. Available: http://www.expansion-energy.com/yahoo_site_admin/assets/docs/Expansion_Energy_LLC_-_VX_Cycle_Overview_PPT.295115525.pdf*
[26] *Statoil, "http://ngc.statoil.com/," [Online]. Available: http://ngc.statoil.com/.*
[27] *LNG Plants, "http://www.lngplants.com/conversiontables.html," [Online]. Available: http://www.lngplants.com/conversiontables.html.*

	Advantages	Disadvantages
Technical	• **Proven technology:** Miniaturization started 10 years ago, and several leading and known suppliers are working and delivering solutions. Other international suppliers, including Chinese, are offering solutions. • **Storage, buffering and transportation of products:** LNG offers great flexibility in terms of storage and trading.	• **Pretreatment and NGLs**: Water and impurities must be taken out in during pretreatment. Liquids and condensate through a simple multistage compression or NGL recovery. • **Operations and Reliability:** LNG plants have been historically subjected to reliability issues and the need for several modules for pretreatment and operation make the operation of the plant fairly complex
Commercial	• **Quality and Premium price**: LNG is very high quality product that it is paid considerably higher than pipeline gas. • **Broad market**: LNG can be placed/sourced to nearby drilling rigs using bi-fuel gen-sets, to isolated gas power stations and small communities, where pipeline cannot access. The LNG can be produced on-site or purchased from LNG suppliers.	• **Complexity:** Business will have to accommodate more engineering, marketing and overhead responsibilities • **Capital:** Investment is not clear, there is a lot of variability and technology it is not readily available for rich gas. • **Lead time:** Months or years to access the product, depending on the size. There are also procurement and transnational trade barriers to overcome.

Factors			**Data**	**Comments: ↑ Advantage ↕ barrier**
TECHNICAL	Equipment	*text*	Equipment requires upfront feed gas compression system, purification and pretreatment (H2S, Cl2, Hg and heavy metals) and NGL recovery units. The equipment liquefaction (different types of cycles and refrigerants) and storage units to build up into modular, skid mounted, portable units	
	Tech.maturity	*text*	Arriving to the market 2013-2014, for conventional natural gas application Untested for tight oil application	
	Reliability	*%*	90 - 99[28]	For large scale plants, 95% reliability it is common, usually > 80% of the time it is running full capacity, and 1-2% of the time there is shutdown. Small scaled plants are expected to have similar reliability, around 96%
	Pressure and Temperature	*Psig* *F*	Min 20bar	Feed gas compression may be needed
	Volume range	*Mcf per day*	200 - 5 000	Larger units are not an issue. Each manufacturer will provide its standard unit.
	Turndown ratio	*text*	Depending on the manufacturer, in principle, product is not affected, but efficiency must be checked with suppliers	
	C3+ content	*text*	Input requires a stream free of liquids (Strict NGL recovery upfront required)	
	Impurities and other components	*text*	Does not tolerate water or impurities. Pretreatment is needed	
	CO_2 Emission Reduction	*%*	< 80	Power on site for the liquefaction process and compressor will emit CO_2 and VOCs. Carbon efficiency and energy efficiency are the most critical aspects related to emission reductions
	VOC Emission reduction	*%*	< 80	
GEOGRAPHICAL	Integration with other wells	*text*	Separation of liquids and integration of a waste gas streams into a gas gathering pipeline is needed to develop this technology	
	Mobility / Deployment	*text*	Skid-mounted re-deployable in weeks. It may require cutting and re-welding. Expensive and not straight-forward operation	
CO	Business models	*text*	Gas Processing and Midstream operations add complexity to O&G operators. Engineering, marketing and overhead is expected to increase	

[28] *Cryostar, "http://www.cryostar.com/pdf/dnl-zone/small-scale-liquefaction.pdf," [Online]. Available: http://www.cryostar.com/pdf/dnl-zone/small-scale-liquefaction.pdf*

	Procurement	*text*	Minimum of 6 – 12 months	
	Capital exp.	*USD/Mcf per day*	500 – 15 000	High variability due to geographical differences (Chinese suppliers), level of development and level of integration of the equipment (pretreatment). Most likely cost is 6.5 mill USD/MMscfd
	Operational exp.	*USD/Mcf*	0.17 – 3.8	High variability, depending on pretreatment, energy efficiency and operations and level of operation and maintenance costs included.
	Revenue per year [29]	*USD/Mcf*	5 - 10	Placing the product internationally (10-15 USD/Mcf) seems unfeasible at the moment and it would also add significant cost for LNG shipping
	Pay-back time	*years*	2 - 6	High variability

[29] *Source: EIA Natural gas prices*

2.3 Mini-GTL FT

Summary of reasons for Rejection:

- Commercialization is ready, but only one supplier has achieved commercial maturity, and only for much larger scale gas fields.
- Technology it is not portable
- More interesting option for large supplies of lean gas, such as from gas processing plants Dry Natural Gas (DNG), mainly CH_4, can be used to produce liquid hydrocarbons, fuels and chemicals[30].

Description of Technology:

Methane is converted into syngas (carbon monoxide and hydrogen) through steam reforming, which is further processed using Fischer-Tropsch (FT) reactions into liquids. In order to maximize production of high-value diesel or related liquids, a hydrocracking processing unit is typically coupled to the FT reactor.

GTL plants are usually very large, capital intensive, and complex[31]. Remote locations and harsh climate conditions pose challenges in terms of site access (including for very large equipment which may not be easily trucked), construction/assembly and plant design (e.g. need for insulation, availability of sufficient water for cooling, etc.). Due to low-margin economics, only a small fraction of worldwide gas fields meet these geographic criteria and thus are suitable to develop conventional GTL plants with competitive economics[32,33].

Mini-GTL or downsizing of the GTL technology to a portable unit is a longstanding goal being approached with new technology. As these technologies mature, miniaturization of GTL technologies may play a role in improving gas utilization in remote areas under favorable local conditions. The minimum range for small scale FT is 2 000 - 10 000 Mcf per day of DNG input[34,35]. Assuming 10 Mcf yields a barrel[36], that would be around 200 - 1 000 bbls per day. Key parameters determining the economic and technological efficiency / viability of these systems include:

- High utilization of capacity is key to economic efficiency (i.e. having stable, long-term gas supplies or a modular/portable solution with good turn-down ratio). Gas processing equipment rarely accommodates more than 50% turn-down, in the case of GTL, its operating time is closer to 80-90%.
- Higher pressure is generally an advantage since the 1st step reformers of most FT reaction routes run at elevated pressures (> 20 bar). Adding compression will add cost.
- Short transport distances to attractive market outlets locally at a significant premium
- The challenges typically posed by using AG as feedstock can be overcome (e.g. limited and changing supply over time)

Best case scenario would be several very productive wells in a remote location with more upcoming wells that serves continuously several small scale GTL-FT units with a processing capacity of at least 5 000 Mcf per day. Production of diesel can be trucked into premium price markets.
Worst case scenario contemplates an overdesigned unit, with a very high cost that cannot adapt to the rapid decline rate of the associated gas.

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[30] *http://www.chemlink.com.au/gtl.htm*
[31] *http://www.chemlink.com.au/gtl.htm*
[32] *The most efficient GTL plant is Shell's Pearl project in Qatar (1.6 BBcfd to 260,000 bbl per day of products; $20 bbn capital expenses) http: / / www.shell.com / global / aboutshell / major-projects-2 / pearl / overview.html*
[33] *GLOBAL METHANE INITIATIVE, "Gas Monetization via Emerging "mini-GTL" Options – Middle East Meeting, Dr. Theo H Fleisch," Washington, October 2-3, 2012.*
[34] *Velocys, "http://www.velocys.com/"*
[35] *CompactGTL http://www.compactgtl.com/"*
[36] *Velocys, "http://www.velocys.com/"*

	Advantages	Disadvantages
Technical	• **Increase liquids output:** Well production increases. • **Storage, buffering and transportation of products:** GTL diesel and naphtha are easily transported liquid with a long development history of safe transport and storage	• **Complexity:** Running a HC processing unit it is not straightforward. • **Dry Lean Natural Gas as input:** Water, condensate and NGLs must be taken out in an NGL recovery process or through a simple multistage compression. GTL is also sensitive to contaminants (H_2S, N_2).
Commercial	• **Premium price:** GTL diesel is a high quality fuel (high cetane and zero sulfur) that can bring a 5-10% premium compared to petroleum based diesel. • **Single, easily accessible deep markets for the product:** Requiring no separate storage or transportation, irrespective of the oilfield location.	• **Complexity:** Complex mixture of products requires significant processing to produce shippable products. GTL naphtha is not valued as gasoline and usually used as a less valuable chemical feedstock, mixing fuel and chemicals sales. It requires downstream competence. • **Competition:** The diesel that is produced (maybe 70% of the total) will be competing directly into the fuel market that is served by the shale oil.

Factors			**Data**	**Comments ↑ Advantage ↕ barrier**
TECHNICAL	Equipment	*text*	Reformer and FT-unit, skid-mounted and modular	
	Tech.maturity	*text*	Large scale GTL is well known proven technology. Small scale units getting commercialized with first batch of units for gas fields. Equipment requires upfront feed gas compression system, pretreatment (H2S, Cl2, Hg and heavy metals) and NGL recovery unit. The equipment includes a re-reforming unit and a FT unit. No orders for tight oil yet.	
	Reliability	*text*	Frequent shutdown/startup are difficult and significantly harm the efficiency of the plant	
	Pressure and Temperature	*Psig* *F*	Min ~ 400 psi	High inlet pressure decreases compression requirements Requires feed gas compression
	Volume range	*Mcf per day*	200 - 10 000 min	
	Turndown ratio	*text*	Best operations of a syngas plant with a conversion reactor will usually require between 85-110% throughputs.	
	C3+ content	*text*	Dry gas has to be the input with minimum ethane/propane - a few percent if not varying	
	Impurities and other components	*text*	Nitrogen and carbon dioxide (max CO_2 ~ 10%) are diluents that can be tolerated in moderate concentrations. In general, H2S is tolerated only for a few ppm, and sulfur and mercury must be removed, but the MSA process can handle H_2S, high CO_2, high N_2, H_2, and condensates without pretreatment.	
	CO_2 Emission Reduction	*%*	60 - 80	Very efficient FT plants can capture about 80% of the carbon feed into products. If there are surges in methane flow, the extra gas will need to be flared, in practice, it would probably be below 70%.
	VOC Emission reduction	*%*	100	Assuming no leaks and fugitive emissions upstream, all of the light gases will be destroyed in the syngas unit.
GEOGRAPHICAL	Integration with other wells	*text*	Integration of several wells together is a must to enable GTL technology	
	Mobility / Deployment	*text*	Time to decommission, disassemble, relocate and start up would be at least a year for a large scale plant, to confirm small scale	
COMMERCIAL	Business models	*text*	O&G operators are skeptical of installing GTL plants in individual gas fields, operated by a single company[37]	
	Procurement	*months*	18 - 36	For mobile assets, time to procure (once) and time to un-install + move + install for any 1000+ bbl /day plant would be at least 24 months (720 days) for a technology that has already been built more than 3 times. For a first of a kind plant, it would probably be 36 months due to learning during project and overcoming startup problems.
	Capital exp.	*USD/Mcf per day*	10 000 - 15 000	A very small plant will have to carry a lot of the cost of installing its own utilities.
	Operational exp.	*USD/Mcf*	1.5 - 2.5	Complexity and skills needed to operate a small plant are much the same as for a much larger plant. Process steam is usually required
	Revenue	*USD/Mcf*	12 - 13	
	Pay-back time	*years*	3 - 4	

[37] *A. Makan, "Gas to liquids: Launch pads proffered for small-scale GTL plants," FT, 16 April 2013*

2.4 Ammonia Production

Summary of reasons for Rejection:

- The technology has not reached maturity utilizing natural gas feedstock at a small scale.
- Some small-scale prototypes for North Dakota have been presented, but it has not been commercialized to date.

Description of Technology:
Ammonia is a commodity chemical that can be produced by combining high-pressure hydrogen and nitrogen to produce ammonia[38]. Nitrogen is obtained from air, which is deoxygenated by the combustion of natural gas. Hydrogen can be obtained from water hydrolysis, but it is usually produced via steam reforming, which converts methane into a mixture of carbon monoxide and hydrogen. More complex treatment may be required to remove impurities before reforming and to maximize hydrogen yield.

Based on literature review we estimate that between 20 and 30 Mcf of gas is required per ton of ammonia[39,40]. The reforming is expected to require 30 – 42 GJ/t NH3 of energy and release 1.68-2.35 tCO2 /t NH3 and the CO2 removal process is expected to release 1.2 t CO2 /t NH_3[41] or 0.027 – 0.05 t CO2 /Mcf[42], which makes up around 1/3 of the ammonia production emissions. Other sources presents that in contrast, process emissions of CO_2 represents around 2/3 of all emissions for very efficient operations. This CO_2 can be captured quite easily, in contrast to the flue gas from fuel combustion, which requires cleaning[43]. Comparing to flare emissions the average emission factor of natural gas would be around 0.01-0.015 tCO_2 /Mcf[44,45], making Ammonia production a gas utilization option that reduced flaring but increases CO_2 emissions on site. Considering lifecycle emissions and displacement of ammonia production it is not part of this study.

Ammonia plants are usually quite large, complex and usually placed close to stable lean natural gas inputs, like pipelines or gas fields. For the case of tight oil production, small scale ammonia plants, of the order of 10 – 100 tonnes per day would be attractive to reduce associated gas flaring. However, "the capital cost of steam reforming plants is prohibitive for small to medium size applications because the technology does not scale down well"[46].

Ammonia it is widely used both as fertilizer (or refrigerant gas) and as a feedstock for fertilizes like nitric acid or cyanides. It is also of interest as a low-carbon transportation fuel. Ammonia price ranges between 400 and 600 USD per metric tonne, and it is typically linked to the oil price in the US and the coal price in China[47]. In the US, a significant portion of production facilities have been dismantled, and currently, imports are critical to meet fertilizer demand. Low US natural gas prices however could revamp interest on delivering lower cost supply of local ammonia to the Midwest.

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[38] Chemguide, "http://www.chemguide.co.uk/physical/equilibria/haber.html," [Online]. Available: http://www.chemguide.co.uk/physical/equilibria/haber.html
[39] OPIC GOV, "Greenpark Petrochemical Company Limited (Nigeria) ammonia/urea plant in Kenai
[40] NETL, North Dakota Industrial Commission and EERC, "End-Use Technology Study – An assessment of alternative uses for associated gas
[41] E. R.Morgan, "Techno-Economic Feasibility Study of Ammonia Plants Powered by Offshore Wind," ScholarWorks@UMass Amherst, 2013
[42] John C. Molburg and Richard D.Doctor, "Hydrogen from Steam-Methane Reforming with CO2 capture," in 20th Annual International Pittsburgh Coal Conference, Pittsburgh, 2003
[43] Fertilizers.org, "http://www.fertilizer.org/ifa/HomePage/SUSTAINABILITY/Climate-change/Emissions-from-production.html," [Online]. Available: http://www.fertilizer.org/ifa/HomePage/SUSTAINABILITY/Climate-change/Emissions-from-production.html
[44] U.S. Environmental Protection Agency, Washington, DC. , "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2010"
[45] EPA Emission Factors for Natural Gas Combustion, "http://www.epa.gov/ttnchie1/ap42/ch01/final/c01s04.pdf," [Online]. Available: http://www.epa.gov/ttnchie1/ap42/ch01/final/c01s04.pdf
[46] http://www.gastechno.com/pdf/GasTechno-Mini-GTL-Data-Sheeet.pdf
[47] http://marketrealist.com/2013/08/wholesale-ammonia-prices-have-been-crashing

Best case scenario would be several large, remote wells which present a softer gas decline rate. O&G operators with a risk-taking profile or engaged into chemical/downstream that sign a mid-term contract to deliver ammonia. Worst case scenario contemplates an overdesigned unit, with a very high cost that cannot adapt to the rapid decline rate of the associated gas.

	Advantages	Disadvantages
Technical	• **New applications fits the scale:** Mini-Ammonia plants can satisfy minimum scale	• **Carbon intensive:** It increases CO_2 emissions on site • **Stable supply:** A minimum reliability of gas supplies is required to ensure optimal capacity utilization of new infrastructure, either in the form of aggregation of multiple associated gas supply sources or through use of a combination of associated gas and a manageable backup supply of natural gas • **Not portable:** It cannot be relocated to new wells easily. • **Dry Lean Natural Gas as input:** Water, condensate and NGLs must be taken out in an NGL recovery process or through a simple multistage compression. Steam reforming is also sensitive to contaminants (H_2S, N_2). • **HSE/Handling of a dangerous compound:** Ammonia is an odorless gas that it is generally classified as dangerous. Special handling and storage attention must be taken.
Commercial	• **Free raw material:** Accessing to free natural gas reduces the operational expenses considerably • **Premium price**: Ammonia access a much higher price per Mcf than other technologies	• **Investment and Payback time:** Investments are large and pay-back time can be delayed due to rapid decline of the gas profile and low cost ammonia and urea imports to the US • **Complexity:** Running an ammonia unit it is not straightforward and possibly not part of the business strategy of Oil and gas companies. Competence both technical and commercial must be built up.

Factors			**Data**	**Comments ↑ Advantage ↨ barrier**
TECHNICAL	Equipment	*text*	NGL recovery and anhydrous ammonia production units	
	Tech.maturity	*text*	Larger units (1 000 to 2 000 Mcf per day) currently on operation (3). No small unit yet deployed	
	Reliability	*text*	95%	Expected to have lower reliability for small scale plants
	Pressure and Temperature	*Psig* *F*	Medium - High	Medium pressure and temperature are required during the steam reforming High pressure and temperature are required in the Haber-Bosch process but it is disconnected from the feed gas pressure and temperatures[48]
	Volume range	*Mcf per day*	100 -	The system does not scale down well due to the nature of catalytic processes, high operating pressures and temperatures.
	Turndown ratio	*text*	High turn-down ratios can be achieved at the reforming unit, but the Haber-Bosch process should maintain pressure and temperature	
	C3+ content	*text*	Liquids components to be removed	
	Impurities and other components	*text*	No sulfur allowed in the process	
	CO_2 Emission Reduction	*%*	Negative	It will produce more CO_2 than it reduces at the flare, depending on the combustion efficiency and power needs of the ammonia unit and the efficiency of the ammonia unit itself
	VOC Emission reduction	*%*	0 - 100%	Depending on the combustion efficiency and power needs of the ammonia unit
GEOGRAPHICAL	Integration with other wells	*text*	Integration of several wells together is a must to enable the technology	
	Mobility / Deployment	*text*	Time to decommission, disassemble, relocate and start up would be at least a year for a large scale plant, to information available for small scale plants	
CO M	Business models	*text*	O&G operators are skeptical of running downstream plants	
	Procurement	*text*	> 18 months	For a demo plant. But at least one year is expected.

[48] *Chemguide, "http://www.chemguide.co.uk/physical/equilibria/haber.html," [Online]. Available: http://www.chemguide.co.uk/physical/equilibria/haber.html*

	Capital exp.	*USD/Mcf per day*	1 600 - 8 690	Available data is very variable
	Operational exp.	*USD/Mcf*	6 - 10	Key operational cost are catalyst and power and heat generation. Gas is considered to be supplied at no cost.
	Revenue	*USD/Mcf*	10 - 25	Fertilizer industry is a net importer in the US. However prices are fairly low even though there is a continuous, but seasonal, demand.
	Pay-back time	*years*	2 - 5 years	Highly linked to project cost

Appendix 3: Technology Case Studies

The following sections presents a number of cases studies and applications of the gas utilisation technologies. The information presented are based on literature review or on supplier interviews.

4.1 Gas Gathering Case Studies

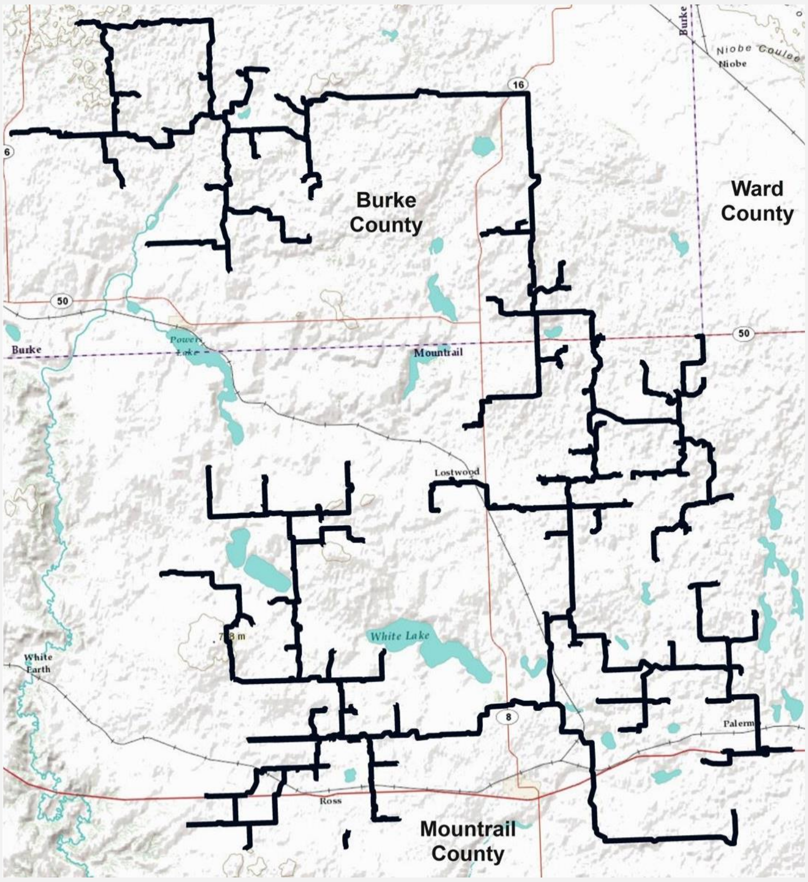
Pilot, demonstration or commercial projects and suppliers

Bison Midstream – Summit Midstream[49,50,51]

In North Dakota, the Bison Midstream natural gas gathering system is composed of 330 miles of pipeline in service of low and high pressure gathering lines (at least 229 miles of polyethylene pipe for low-pressure gathering and 70 miles of high pressure steel pipe) as well as six compressor stations (5,950 hp) in Burke and Montrail counties, that are part of a compression horsepower of 7 200 hp. Average daily throughput is 17 000 Mcf per day, and the total capacity of the system is around 30 000 mcfd. The central discharge pipeline destination in Aux Sable's Palermo Plant.

The Bison system is supported by producer commitments from over 675,000 acres and fee based agreements are in place for >$155 million in revenue through 2020. Additional agreements are currently being negotiated".

Figure 2: Bison Midstream natural gas gathering system. Source: Bison Midstream



[49] Summit midstream, "http://www.summitmidstream.com," Summit midstream, [Online]. Available: http://www.summitmidstream.com/assets?id=3

[50] Summit midstream, "http://www.summitmidstream.com," Summit Midstream Partners, LP, [Online]. Available: http://www.summitmidstream.com/docs/smlp%20acquisition%20-%20bison%20mountaineer%20(6%205%2013)%20final%20docx.pdf.

[51] http://bakkenshale.com," [Online]. Available: http://bakkenshale.com/pipeline-midstream-news/summit-midstream-buys-bison-midstream-natural-gas-gathering-operations/.

EPA Gas Star Program[52]

The EPA Gas Star Program is focused on fugitive emissions reduction, but they present an interesting case study on infield compression. This study showcases the cost of replacing flaring with the delivery of associated gas to a gas sales line.

"Methane savings of 32,850 Mcf per year are based on recovering 180 Mcf per day of associated gas containing 50 percent methane, by installing a 30 horsepower electric rotary compressor capable of delivering gas into a 100 psig sales line. Capital cost is estimated at 12,500 USD, with installation assumed to be 1.5 times equipment cost. Therefore, total implementation costs are estimated to be 31,250 USD. Operation and maintenance (O&M) costs are primarily electricity, and are estimated to be 7,350 USD using the following formula:

O&M = engine horsepower * OF * 8,760 hours/yr * electricity cost
where the price of electricity is assumed at 0.075 USD / Kwh, and the operating factor (OF) at 0.5.

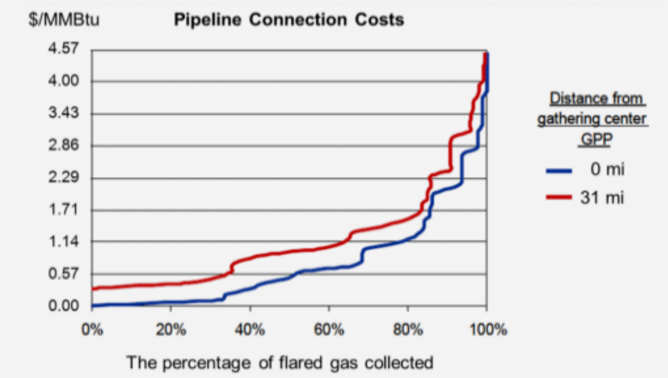
This technology has a quick payback when sufficient gas can be captured. The primary justifications for implementation include the additional revenue from sales of captured gas as well as the increased well productivity. Although there will be increased O&M costs, the additional income resulting from the sales of recovered associated gas will offset the costs."

Theoretical examples

Using Russia's Associated Gas. PFC Energy[53]

PFC Energy estimated the Gas Processing Plant (GPP) connection cost to vary wildly depending on geographical location, flow, and compression needs. It also presents a correlation between pipeline cost, percentage of gas flared, and distance to a gas processing plant. It is worth highlighting that collecting more than 75% of the flared gas would exponentially increase the gas gathering costs.

Figure 3: Pipeline Connection Cost for Capturing Flared Gas. Source: PFC Energy (2007)



[52] *EPA GasStar Programme http://www.epa.gov/gasstar/*
[53] *PFC Energy World Bank, "Using Russia's Associated Gas," December 10 2007.*

“Debottlenecking your gathering system case study” by Natural gas consultants[54]

The following example presents data on centralized gas gathering and compression.

“A production company has a gathering system that moves approximately 23,500 Mcf per day of gas from wells they operate. The main compressor station operates at 75 psi suction pressure. The system also has four satellite compressor stations, totaling approximately 2,900 horsepower (HP). By reducing the main compressor station suction from 75 psi to 35 psi and installing 2.7 miles of 10” full well-stream gathering line and 3 miles of 6” gathering line, the hydraulic model showed that the satellite compressor stations can be eliminated. The centralized compression fuel usage increased by 198 MMBtu / day but 230 MMBtu / day of field compressor fuel was eliminated. Additionally, an estimated net savings of 35,000 USD per month in compressor rental fees was eliminated. After reducing the fuel and rental fees, the average field pressure would be lowered from 110 psi to 55 psi. Additionally, it was estimated that a 10% production increase would also be realized due to a reduction in well loading problems and increased inflow performance from older wells as well as make room for budgeted development drilling projects”

For a case of compression centralization and pipeline looping in various counties in Texas, the author expects:

- Initial gross flow rate of 20 000 Mcf per day, an estimation of 50 - 70 wells or ~ 10 leases.
- Capital investment of 4.3 million USD, which it is less than 100 000 USD per well.
- Operational expenses: 0.05 USD / Mcf
- Recovery through a gathering fee of ~ 0.250 USD / Mcf, which allows operator not to pay upfront.
- Pay-back time in 3 years for the developer, but very short pay-back time for tight oil operators.

[54] *Natural Gas Consultants, “De-bottleneck Your Gathering System”.*

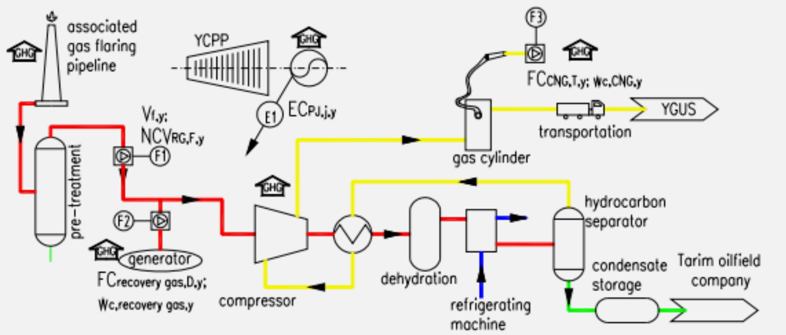
4.2 CNG Trucking

Pilot, demonstration or commercial projects and suppliers

Tarim Oil field CDM Project[55]

The Tarim oil wells associated gas recovery and utilization (CNG) CDM project[56] in Xinhe county in Akesu Area (China) installed two skid-mounted recovery stations to recover associated gas that would otherwise be flared, and then process it into condensate and CNG.

Figure 4: Flow diagram for each of the CNG recovery stations. Source: PDD document of the Tarim Oil field project



F1:processing vortex flowmeter F2:intelligent processing vortex flowmeter F3: flow meter E1: electric energy meter

Table 1: Overview of the Tarim Oi field CDM project

Equipment	Quantity	Type	Specifications	Conversion	units
Pre-treatment instrument	1 x 2 recovery stations[57]	NGS-30/0.2-1	4.32×10^4 Nm3/d	1609	Mcf per day
Compressor	3 (2 in recovery station II)	M-8.5/2-220	1.45×10^4 Nm3/d	540	Mcf per day
Gas generator	2[58]	600GF1-PwT	600 kW		
Dehydration and condensate separation	1 x 2 recovery stations	NGT-25/2.2CL	0.6×10^4 Nm^3/d	22.35	Mcf per day
In addition, 9 semi-trailers with LPG tankers and 5 tractors were used as CNG trucking medium					
Capacity	~10 ×10^4 Nm3/d			3725	Mcf per day
capital expenses	4,565 * 10^4	RMB		7.5	mill USD
operational expenses	1,084 * 10^4	RMB/a		1.77	USD
IRR (Internal rate of return)	7.23	%, excluding CERs revenue			
CO_2 emission reductions	62 446 tCO_2 /a of baseline emissions – 751 tCO_2 /a of project emissions = 61 695 tCO_2 /a of emission reductions				

[55] *https://cdm.unfccc.int/Projects/DB/RWTUV1249652203.75/view*
[56] *UN Clean Development Mechanism (CDM)*
[57] *Recovery station I has a designed Capacity of 2.5×10^4 Nm3 / d, load factor of 60% and efficiency of 90%, while Recovery station II has a design of 5×10^4 Nm3 / d, a load factor of 80% and efficiency of 90%.*
[58] *Including 1 for emergency, but only in one of the recovery stations. The other one it is supposed to run on power from the grid.*

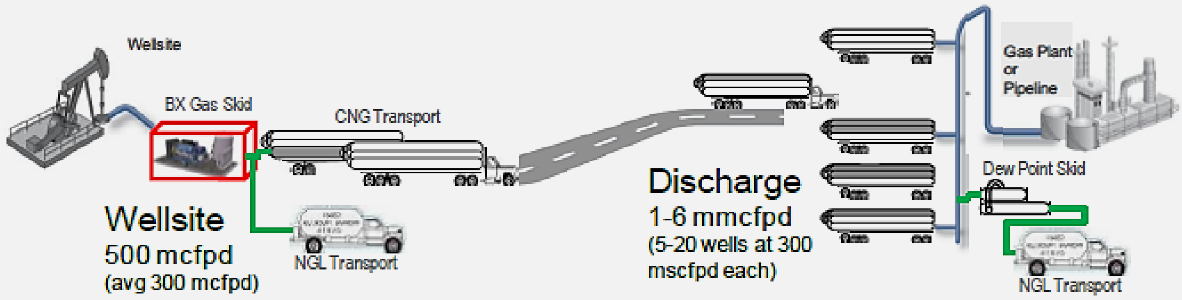
Bakken Express LLC[59,60]

Bakken Express was founded four years ago as a service provider of technological options to capture, compress and transport stranded gas & liquids with operations based in North Dakota.

At the beginning, in collaboration with the Industrial Commission of North Dakota, they financed and developed the project "Wellhead Gas Capture Via CNG Technologies", a 12-month pilot project to evaluate the viability of applying compressed natural gas (CNG) technologies to economically capture and transport produced natural gas and gas liquids from 5 selected wells to market.

The process is quite simple. The gas will be dehydrated to under 0.5 lb/Mcf water content[61]. Then, the compressor skid boosts the pressure from 15 psig to 3,500 psig, which enables the tube trailer to carry 210 Mcf per load. A well producing 500 Mcf per day of associated gas would require about 3 loads a day. When a tube trailer is nearing its maximum capacity, a truck is dispatched with an empty tube trailer. This one is set in position next to the compressor skid and is hooked up to the manifold. Then, the full tube trailer is disconnected and taken to the discharge facility, which is located adjacent to a gas gathering or sales gas pipeline.

Figure 5: Wellhead Gas Capture Via CNG Technologies project diagram . Source: Bakken Express LCC and the North Dakota Industrial Commission.



Key parameters of the project proposal were:

- 5 locations producing 675 Mcf per day per well or 3,375 Mcf per day in total gross gas volume and 2,500 Mcf per day net gas volume.
- Capital expenses
  - 1.5 mill USD invested on 5 dew point gas skids composed mainly by a 4 or 5 stage reciprocating compressor each.
  - ~ 0.3 mill USD on supervisory, engineering, consulting and principals
  - It also assumes that a pipeline tap, gas processing plant or CNG fuelling station is available within 50 miles for unloading/sales.
- Operating expenses (per year)
  - 0.22 mill USD on tube trailer[62] leasing
  - 0.026 mill USD on discharge facility leasing on both ends
  - 0.06 mill USD on operation and maintenance.

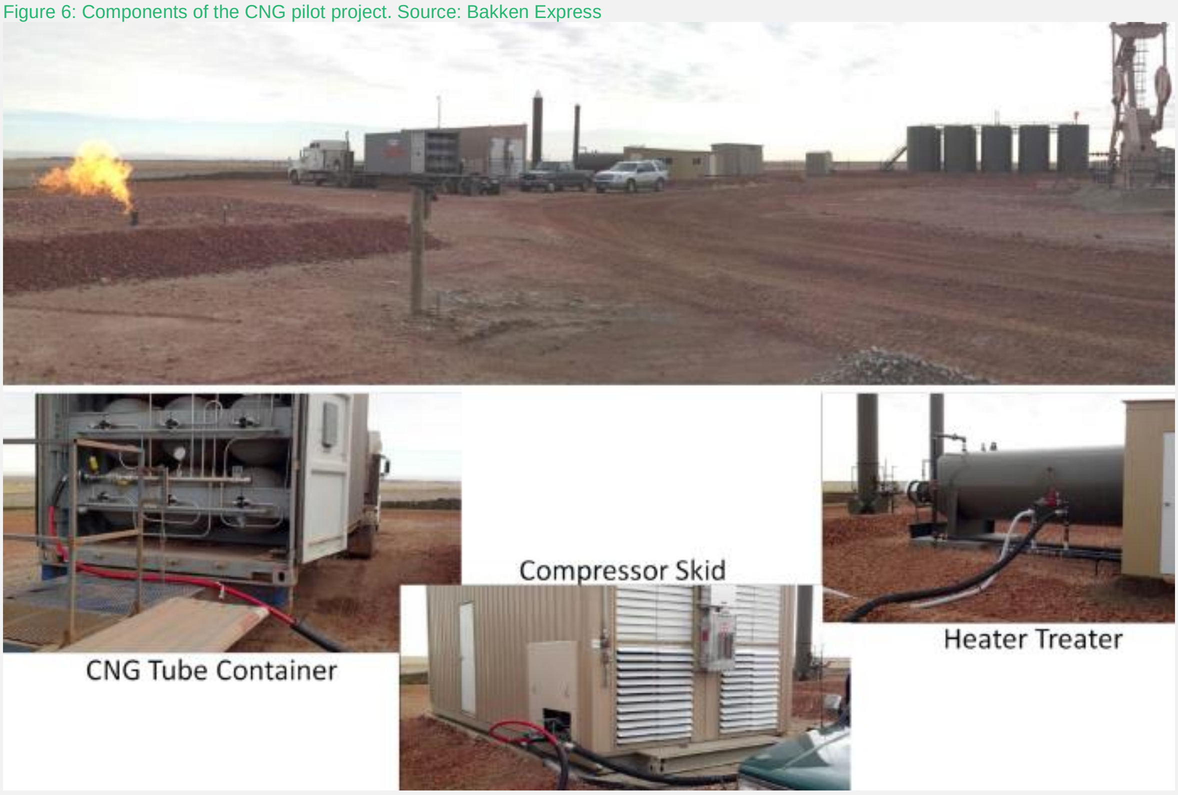
However Bakken Express, LLC proposed at that time (2013) a business model based on in-kind fee for the wellhead gas capture service, with no up-front capital or binding period [63]:

MCFD	400-500	300-400	200-300	100-200
Fee/Day	$700	$700	$700	$700
Fee/MCF	$1.56	$2.00	$2.80	$4.67

According to an interview with the company about their current status of development and technology performance, the pilot project achieved the goals and proved the technology ready. The current product it is currently used by several tight oil operators at the same time, proving the maturity of the technology. The following pictures show some of the equipment from the project.

[59] *http://www.nd.gov/ndic/ogrp/meet1008/propg-022-c.pdf*
[60] *http://www.mtpeakbuilders.com/bakken-express/*
[61] *Extra processes needed are dehydration of gas to 0.5 lb / mmscf water content (using molecular sieve technology), high pressure quick connection / disconnection (using CNG hoses) and the discharge facility to depressurize the tube trailers and dew point the gas.*
[62] *Type 1 3AAX steel tubes, which is covered by DOT special permit 8009*
[63] *Following that in-kind fee structure, Bakken Express also presents that "on a well with an IP of 1,050 bopd and 600 mscfd, these technologies should capture 129 million scf of lean gas and 15,700 bbls of liquids in the first 12 months. Assuming a service fee of $700 / day, gas values of $3.50 / mscf and NGL values of $0.80 / gal, this operation should be economic for both the service provider and the producer (who would net $525,000 [or $3.67 / mscf], after transport costs, in the first year)".*

Figure 6: Components of the CNG pilot project. Source: Bakken Express



4.3 NGL Recovery

Pilot, demonstration or commercial projects and suppliers

PETROGAS SYSTEMS[64]

Petrogas Systems it is a long-standing supplier of the oil and gas industry. They have been delivering liquid recovery units worldwide and since recently they have proven experience (several units) in Bakken.

They offer portable, modular process skids composed by a basic system and a stabilizing system. The equipment it is designed to operate -40°F, handle pressures from ambient to 1,000 psig and it is scaled to suit tight oil operations, with flow rates from 50 Mcf per day to 40,000 Mcf per day and snow protection.

For the mechanical refrigeration either dehydration or atomized methanol injection is needed to prevent the formation of ice. Operators can decide to opt for one system or the other depending on their strategy: Dehydration is an investment that pays in the long run, while methanol supply is a short term runner, requiring several gallons of methanol per day and a storage tank to operate more than a month without supplies.

The mechanical refrigeration can separate all heavier components, including around half of the propane. Separating the C_3+ needs a compressor, which adds complexity to operations, however, very little maintenance work is needed, usually a monthly check and oil cleaning and change every three months. They also supply a PLC unit to monitor performance and reliability. The compressor, with a valve upstream, it is also good to regulate the highly variable inlet gas pressure.

Regarding the design strategies, here there are some possible alternatives that the supplier can offer:

- Purchase of 1 unit with estimated design flow, allowing to go over 20% and down 20-70% on terms of volume without losing recovery rate. Peaks or times with low volume and pressure would leave the lean gas with higher Btu, affecting latter utilization like power generation.
- Purchase of 3 units running on parallel, covering 60 - 90% of the expected peak volumes. Demobilizing and relocating units to new wells as flow goes down. Relocation operations may take as little as one day.
- Leasing of 1 unit for the estimated flow rate during a period, then leasing another unit for a lower estimated flow rate during a period, then leasing another one for the lowest flow.

Procurement time can be around 15 weeks, depending on the upstream suppliers, with no restriction on order volume. Petrogas Systems also couples the NGL recovery unit with power generation, but we treat that as a separate technology.

Vortex tools[65]

It is a company that has been working since 2001 on different surface and subsurface oil and gas operations.
They sell a field processing solution which is purely mechanical. It is based on a high velocity spinning vortex flow separating a two- or three-phase flow into its liquids and gases. It will not separate ethane from the methane, but it will collect all C_{10}+, and an important quantity of the C_3+. More of the water vapor is also collected as water. According to Vortex, the solution is very small, scalable, portable and robust. It handles high or low temperatures and design pressures and impurities (H_2S and CO_2) can be solved by specifying them on order.
It can receive gas from the separator (300-psi) or the treater (40 psi). In the gas gathering line (2"-24"), the Vortex tool can move gas at 20-25 psi suction pressure, or higher pipeline pressures after compression if needed. According to the supplier, it can reduce liquids carry over in flaring lines. It can also be placed in gas gathering lines or pipelines, extracting up to 10x more NGLs in long lines (fighting NGL pooling). The tool solves many issues with water knockout, bs&w, liquid carry over and problems with salt, paraffin, hydrates and freeze ups.
Vortex deliver the system as a product, with relatively inexpensive price. The largest expense of a wellhead development it is the cost of installation, piping and tanks, which it is carried by subcontractors of O&G operators, usually as part of other developments like installing the flaring system. Operational cost are minimal since it is a mechanical unit, with no moving parts, requiring little maintenance. They estimate a pay-back time to be as low as 60 days. They also offer leasing agreements, so O&G operators can lease different sizes to match declining gas profiles.

The product carries over many years of experience and unit in the market (1,500 Vortex worldwide), including 150 – 200 units to conventional oil and shale gas operators. They are right now on the way to commercialize in the Bakken and Eagle Ford.

[64] *Interview conducted*
[65] *Vortex Tools, http://vortextools.com/tools/surface/sx-ngl.html*

Blaise Energy[66]

Blaise Energy is a company providing flare reduction alternatives and gas utilization option. Its main product it is power generation from flare gas, which we will treat more in detail in the power generation chapter. They also provide NGL recovery services based on their own Btu stripping unit. It separates C3+, while leaving most of the ethane in the gas stream.

GAS STAR EPA Programme Salem Case Study[67]

The project aimed at handling associated gas from a mature oil field using bio-desulfuration prior to mechanical refrigeration[68]. 700 Mcf per day of incoming sour gas yielded 340 Mcf per day of lean gas and 4 500 gallons of NLGs per day. The project generated revenue of 0.034 mill USD per year from lean gas sale and 0.158 mill USD per year on NGL sale, and achieved 125 MMCF methane emission reduction per year.

Theoretical examples

EERC Research[69]

This study evaluates NGL recovery for a base case scenario with economic cutoff of 600Mcf/d and design flow of 1 000 Mcf per day of associated rich-gas (1 400 btu/cf and 10-12 gallons of NGLs) yielding 4 gallons NGL per Mcf.

In terms of costs, the project would require a capital investment of 2.5 mill USD[70], with 10% operational expenses. The project would result in an NGL annual revenue of 0.7 mill USD for the 600 Mcf per day rich gas flow rate and ~ 1.17 mill USD for the 1 000 Mcf per day case (assuming a NGL price of 1 USD/gallon).

Vantage pipeline[71]

Bakken associated gas utilization example for both refrigeration and cryogenic processes, producing 629 and 1 012 NGLs barrels a day (26 418 and 42 504 gallons a day)[72] respectively out of a 4 000 Mcf per day gas stream.

Aspen[73]

The study assumes that a typical small Bakken well produce 750 Mcf per day of natural gas. Process simulations showed that NGL recovery can produce 144 barrels per day of NGL (6 048 gallons per day of NGL[74]), worth $250,000 per month (3 mill USD per year) while providing lean compressed gas.

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[66] *http://www.blaiseenergy.com/*
[67] *http://www.epa.gov/gasstar/documents/workshops/2012-annual-conf/finch.pdf*
[68] *The equipment supplier was Hy-bon Engineering*
[69] *NETL, North Dakota Industrial Commission and EERC, "End-Use Technology Study – An assessment of alternative uses for associated gas*
[70] *including heater / treat at 35 psi up to 200-1000 psi delivered to the NGL removal system as wells as the cost for four 400-bbl NGL storage tanks*
[71] *Gord Salahor, VP at Vantage pipeline, "EIA Virtual Workshop on Natural Gas Liquids: NGL Market Development Example*
[72] *EIA Assumption of 1 metric ton NGL (natural gas liquids) = 10.4 barrels, and 42 gallons per barrel.*
[73] *Aspen Engineering Services, , "Solutions for the oil and gas industry: NGL Recovery".*
[74] *EIA Assumption of 1 metric ton NGL (natural gas liquids) = 10.4 barrels, and 42 gallons per barrel.*

4.4 Power Generation Technology

Pilot, demonstration or commercial projects and suppliers

LPP Combustion[75]

LPP combustion is a supplier of truck-mounted mobile power systems, without Balance of Plant, for oil and gas operations. They use well-known reliable suppliers for the gen-sets, and then they use a separate fuel preparation skid to apply their patented technology (Lean, Premixed, Pre-vaporized combustion of liquid fuels). The technology allows for a rapid load-following, high performance, on-the-fly fuel switching and blending operation. These power systems can operate a wide range of pressures on C1-C8 fuels to provide electric power with natural gas emission levels, including Low-NOx and Ultra Low-NOx requirements. Due to high variability on supply, a site-specific back-up system it is usually attached. Ethane and propane can be separated from the gas stream and stored on-site as liquids, providing several days of back-up fuel. They can deliver equipment from 100 kW to 25 MW. The equipment can be re-deploy in one day and can be accommodated for severe weather conditions.

Equipment it is normally designed to match associated gas composition from the gas well. This can be challenging, since a gas sample it is needed, possibly the procurement process cannot start prior to well drilling and completion. Possibly the equipment can only be delivered after several months of operation.

Also, although this new technology has been tested extensively in the research facilities, it is in its initial phase of commercial development, with first large orders in place.

According to the supplier, the costs estimates are in the range of commercial gas turbines for these sizes, with the added technology not changing significantly the cost and allowing substantial fuel and emission savings with an expected pay-back time of a year. Low maintenance cycles and costs are expected, with a maximum of 10 - 20% on operation costs.

They offer direct sale of the product, but preparing for leasing arrangement in 1-3 years' time. This may help the operators to utilize flexible approaches when designing their gas processing systems.

Wellhead Energy Systems[76]

Wellhead systems only requires a minimum 200 Mcf per day of associated gas volumes and 75 psi pressure to produce power and space for the system in the wellpad. The GridFox TM product offers a range from 0.5 MW to 2 MW for local loads or directly to the grid and can be set up and deployed quickly. It includes balance of plant and the possibility of providing heat and steam.

It is designed for remote, and sub-standards gas assets through a gas purchase via long term fixed price with no capital investment. They also offer a system purchase, with expected payback time in less than 5 years and options for accelerated depreciation with a price per Mcf to be determined based on the price per kWh. Both options include treatment of contaminants (sulfur, nitrogen and excess water), no high compression needs and no transport or broker fees.

[75] *http://www.acmepowersystems.com.*
[76] *Wellhead Energy Systems, Wellhead Energy Systems, http://wellheadenergy.com/*

Blaise Energy[77]

Blaise Energy started in 2008 company using associated gas to deliver power from its generators to the power grid. Projects were backed from grants and industry collaboration. However, electricity prices paid were low and process complicated and highly bureaucratic. It is, in general terms, more efficient to power wells directly, leading to considerable fuel savings.

Blaise Energy offers mobile, scalable power generation from 100 kW to multi-megawatt power generation units for oil and gas operations and local loads on-site. Also, they offer micro-grid developments, so their units can power industrial units if they are close to the wells, some examples are industrial loads of 1.2 MW (4x300 MW units) for water disposal and other O&G processes. Right now they running several services for oil and gas operators.

They are having a pilot on a NGL (Natural Gas Liquids) Recovery unit, which lowers the BTU and recovers the heavier hydrocarbons such as Propane, Butane and Natural Gasoline. There is interest on utilizing the lean gas for further uses, they have been approached by other supplier to partner and develop mini-CNG and mini-LNG solutions at specific sites, not as a widespread solution, but for certain cases. They are also still offering grid power services, which brings extra revenues from RECs.

Blaise Energy has developed its own gas scrubbing system to decrease pressure and acts as a buffer for the gas coming out of the gas separators and treaters. Power units use different types of diesel-derived engines, retrofitted and flexible regarding combustion parameters. If the gas is sour it would require treatment by the operator and if the gas presents very high Btu, it would require de-rating of the motor side load. They have a propane back-up so operations can always take place.

Regarding system design, units are usually sized to take only the valleys of production, not the peaks of the gas volumes. For a production of 100-300 Mcf per day, they are using around 10-20% of the gas, the rest is flared. Usually there is not enough demand on site, between 0.1 - 0.15 MW for single well and 0.25 - 0.5 MW for multi-well pads. Semisubmersible pumps and pump jacks are common loads at site. Reliable power can be achieved if it is designed this way. If the operator changed the load, a new unit can put in parallel, de-rate, or one unit can be taken out.

According to Blaise Energy, units can be deliver as shortly as 1 day if they are on stock, but can be months of lead time to order new if not in stock. So far, they supply only in North Dakota. Service is 24/7, and a skilled team is supporting operations, for instance, to perform the just mentioned task of changing a load. Equipment it is skid-mounted, and can be moved by the operator with supplier support within a day as long as there is sufficient coordination. The NGL recovery it is also portable, but it may take up to a week or two. Blaise Energy rents its smaller generators for 5 000 – 6 000 USD / month and its larger generators for 10 000 – 12 000 USD / month on the upper end. Fuel savings can be up to 20 000 – 25 000 USD / month[78].

Petrogas Systems and Caterpillar[79,80]

PetroGas Systems has partnered with Caterpillar to deliver gen-sets that are able to run on liquid rich, high Btu gas. Since associated gas is considered as zero cost, it is possible to keep a gen-set running with costs around 3 USD / MWh, which it is considerably lower than current electricity prices. Combined with Certified Emission Reductions (CERs) due to flaring reduction, it becomes a very attractive option.

GTI Bi-fuel systems by Altronic plus Continental resources, Cyclone Drilling Local and the support of EERC, NREL and NDIC [81]

A project to evaluate the application of bi-fuel modes in three Caterpillar 3512C (four-stroke cycle) diesel engines of 1.1 MW. Simulated gas was used at replacement rates exceeding 40% demonstrated that such operation is feasible, achieving significant fuel savings. However, due to the wet nature of the gas, the replacement rate is limited to 60% due to engine knocking, and also slight increases in exhaust temperature and changes in the combustion properties and final emissions.

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[77] *Blaise Energy LLC, http://www.blaiseenergy.com/.*
[78] *http://highspeedcharging.wordpress.com/2011/05/03/day-in-the-life-of-a-pump-jack/.*
[79] *Petrogassystems, "http://petrogassystems.com/technology/natural-gas-processing-and-dew-point-control," Petrogassystems.*
[80] *Interview conducted*
[81] *EERC NETL NDIC, "Demostration of Gas-Powered Drilling Operations for Economically Challenged Wellhead Gas and Evaluation of Complementary Platforms," 2013.*

Encana resources[82]

Encana resources is operating 6 dual-fuel technology and 10 dedicated natural gas engines in natural gas-powered rigs. Of those, 12 use field gas produced from the fields in which they are drilling and the rest (4) use *LNG because of limited natural gas distribution availability in the field*[83]. In the following paragraphs we reproduce the text from the source, since we believe it is a worth-to-highlight extract of this case study:

"The greatest benefit to field gas is cost. Comparing natural gas with diesel for an Encana rig in the Jonah Field that uses conditioned wellhead gas with backup diesel costs, hookup and fuel gas unit costs, the natural gas rig costs 26 710 USD per well, saving 115 040 USD in fuel costs on every well drilled compared with the diesel-powered rig. The savings can be significant when multiplied over multiwell programs and a multiyear deployment of a rig in a field.

While Encana has realized tremendous fuel benefits from field gas, less refining and a reduction in truck trips, we have experienced issues that we are working to address to increase performance. Initially, we saw a high frequency of "blackouts," with rig crews unaccustomed to the torque response. In addition, the effect of elevation is greater, resulting in a higher "deration" factor (14 percent versus 6 percent) with a rig located at an altitude of 7 200 feet. Tuning the engines to help achieve higher power also gave us spikes in NOx numbers, an inconsistent fuel supply from our central distribution point (leading to pressure and volume issues), and a higher-than-anticipated amount of backup diesel burned.

Changes to natural gas delivery and our quick-move design for vertical wells have caused additional gas consistency and reliability challenges. The initial delivery design produced large temperature swings, resulting in a liquid knockout, slugging of engines with condensate, freezing issues with delivery lines, and general inconsistencies in fuel delivery.

Encana has addressed some of these issues with early field gas testing. Load bank installation on generators has helped moderate load swings and has allowed us retune our engines. We also are obtaining gas samples from different central distribution points to help tune engines accurately. Finally, we developed a system to educate crews to operate the rig effectively.

To solve delivery issues, we have created a dedicated fuel gas team responsible for the initial setup of our fuel lines and desiccant system (designed to condition gas), troubleshooting problems during drilling, and performing routine blow-downs of our lines. We also increased the size of delivery lines to two to three inches, which has limited pressure drop at the engine regulators.
Going forward, we plan to eliminate the three lines to location concept (fuel gas, hydraulic fracturing and sales lines) in the Jonah Field, implement a robust fuel gas delivery conditioning system that is engineered for wider use, and expand technologies to other fields"

GE and Seneca Resources[84]

Seneca Resources has 15 LNG-powered rigs operating in the United States; 11 of those are operating exclusively on GE's Jenbachers. As an example, they replaced diesel engines by turbocharged natural gas engines (GE 1MW Jenbacher J320) on two rigs working on unconventional gas. The 320's turbocharger keeps the machine operating at peak performance with low gas pressure and producing enough power to supply all operations on the rig (0.5 to 1.1 MW), while reducing emissions up to 25 percent.

Saks Power

The utility company Saks Power in Canada, allows new oil facilities with power producing units over 100 kilowatts (kW) and up to one megawatt (MW), licensed after July 2012 to join its innovative Flare Gas Power Generation Program[85]. It offers, for a fee below 2,000 USD, $75.02/MWh standard 20-year contracts for power generation projects, escalating annually at a rate of 2%. This offer is not applicable to the selected plays but opens up for potential scenarios where natural gas power generation is promoted.

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[82] *Encana Resources http://www.aogr.com/index.php/magazine/editors-choice/encana-initiative-environmental-economic-benefits-powering-rigs-natural-gas.*
[83] *They comment that "LNG is more expensive than field gas because of liquefaction, transportation and regasification costs", however "LNG offers the ability to move rigs outside of an area that is using field gas and provides a high-quality and reliable source of fuel" highlighting the fact that the fuel supplied needs to be highly mobile because of short drilling operations (1 month) and still positive economics "Encana is averaging $500-$1,000 a day in fuel cost savings with LNG compared with diesel engine rigs".*
[84] *GE and Seneca Resources, http://www.ecomagination.com/unconventional-gas-innovative-power-ge-jenbacher-engines-powering-lng-fueled-drilling-rigs.*
[85] *SaksPower Flare gas power generation program*

Theorethical examples

Lean gas after NGL recovery to power grid and local loads by EERC NTEL NDIC [86]

This study presents different alternatives for power production from lean gas after NGL recovery. The capital costs and expenses only include the power generation items, excluding NGL recovery:

Table 2: Technical and economical parameters of power generation technologies utilizing associated gas in Bakken

Delivery	Engine	Nameplate capacity (generators x capacity)	Fuel Pressure	Gas input	Electricity production	capital expenses Gen set	capital expenses Balance of plant	capital expenses	operational expenses	Revenue Estimate	Payback time
		MW	*Psi*	*Mcf per day*	*MWh per day*	*mill USD*		*USD/KW*	*mill USD*	*mill USD*	*Years*
Grid	Reciprocating	5.1 (3 x 1.7)	1-65	850	114	4	1	~ 800	0.40	1.66	~ 4
Grid	Gas turbine	6 (3 x 2)	100-500	1 530	140.4	6.4	1	~ 1 000	0.64	2.01	~ 5
Local	Reciprocating	1 (4 x 0.25)	1-65	100	6	0.2	0.5	~ 700	0.02	0.16	~ 5
Local	Microturbine	0.26 (4 x 0.065)	55-90	49	4.7	0.4	0.5	~ 3 200	0.03	0.12	~ 10
Local	Microturbine	0.4 (2 x 0.2)	55-90	68	7.6	No economic data in this case					

[86] *NETL, North Dakota Industrial Commission and EERC, "End-Use Technology Study – An assessment of alternative uses for associated gas*

4.5 Mini-GTL MT

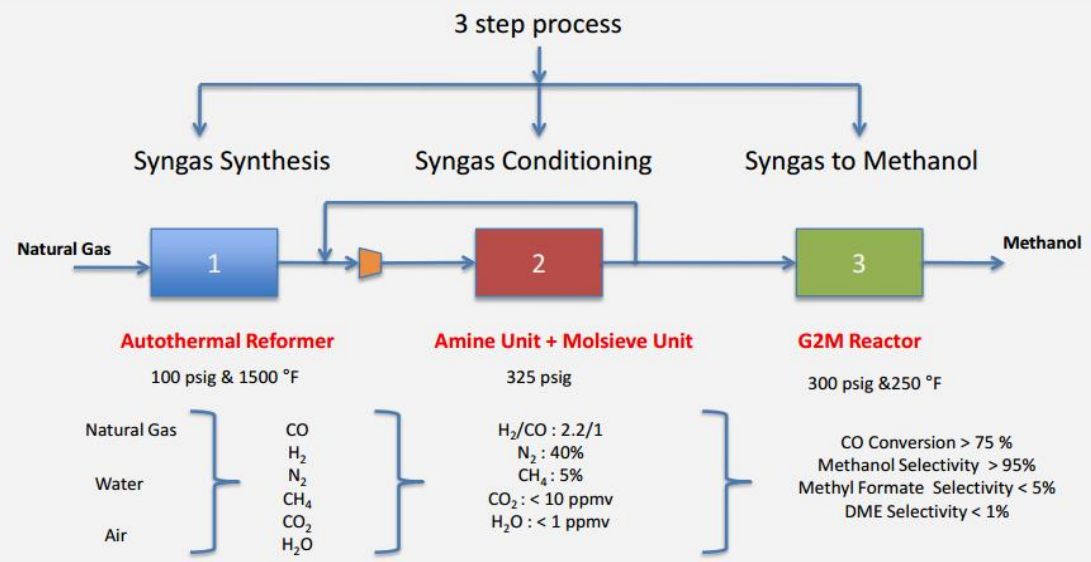
Pilot, demonstration or commercial projects and suppliers

R3SCIENCES[87]

R3Sciences is developing a 3-steps process: syngas synthesis, syngas conditioning and syngas to methanol. Medium-pressure (300 psi) and low-temperature process (239 °F).

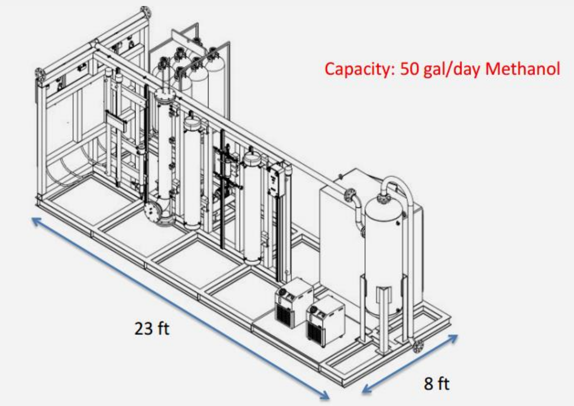
According to the supplier, it exhibits extremely high selectivity (>95%) to methanol—nearly pure reaction products, higher syngas conversion per pass (>90%, compared to <16% for conventional systems) and stability of the catalyst on stream, therefore eliminating the need for recycle. It can handle higher concentrations of inerts (<50%) compared to conventional systems (<1%).

Figure 7: R3SCIENCES Processes (source R3SCIENCES)



Their plan is to develop a pilot scale methanol unit of 50 gal/day that you can see in the Figure 27 by 2014.

Figure 8: R3SCIENCES Pilot skid layout (source R3SCIENCES)



Afterwards, their plan is to develop a larger prototype of 2 000 gallons a day of methanol, and accept commercial orders at the end of 2015.

[87] *http://www.enersciences.com/r3-sciences/technologies/GTL_Srinivasan%20Ambatipati_R3%20Sciences_073013.pdf*

GasTechno[88,89,90]

GasTechno® is a technology provider established in 2004 that since 2010 has carried construction, testing and field demonstration mini scale GTL units. GasTechno® is divided in two companies, the parent company, GasTechnologies LCC which is responsible for FEED, construction and technology licensing and GasTechno Energy & Fuels USA LLC, which holds exclusive patent rights of the technologies for the USA Territory of GasTechno and it is responsible for developing projects, including permitting, installations and maintenance.

The Mini GTL plant is a cargo-container or trailer-mounted, compact unit (entire site footprint including storage & oxygen is 90 ft x 70 ft) based on a non-catalytic partial oxidation gas-to-liquids technology that converts small scale sources of associated gas into to methanol in one step. The reactor works as a loop process, keeping most of the flow circulating, which also reduces the impact of dramatic associated gas surges. It accepts low/high Btu off-specifications gases, high N_2/CO_2 concentrations and presents a moderate carbon efficiency (50-70%) without expensive catalyst or pre-treatment, except if H_2S is present. It generates water, which needs to be clean up for delivery or disposal at a new or existing well and requires electricity and oxygen (oxygen generator or liquid oxygen) supply on site. The process would probably vent a minimum of 20% of the carbon as CO_2 and capture the rest as liquid. It is possible to relocate in as little as one day, but it may take between 8 to 24 hours to start the unit again since it needs to build up pressure and temperature. Software is included and it is operated by controls designed for oil field personnel that requires start/stop features, making operation quite simple.

Figure 9: GasTechno Mini-GTL TM Plant

During 2012 GasTechno introduced an early adopter program. One Portable Mini-GTL demonstration facility (25 foot mobile cargo trailer) was deployed at a producing natural gas facility, operating with off specifications wet gas with changing energy content (1 050 to 1 400 Btu), relatively low methane content (62.67%) and high nitrogen, ethane and propane content (18.21%, 12.3% and 5.33% respectively).

In 2013 GasTechno started the commercialization of the GasTechno Mini-GTL Plant. Such a plant it is designed to adapt to the flaring conditions of North Dakota, where the production decreases rapidly and the gas-oil ratio increases over time. Application of the technology at drilling and completion sites it is another alternative, not yet proven though.

Minimum designed capacities range from 75 Mcf per day to 500 Mcf per day, and it is estimated that the minimum scale commercially viable to be 200 Mcf per day, which is "*mostly those flare volumes in the Bakken of North Dakota*". It delivers a mix of NGLs (natural gas liquids), methanol, ethanol, formaldehyde and fuel intermediate, which must be marketed to a separator, with expected revenues of around 15 USD/Mcf per day. Estimated capital expenses could be from 0.5 mill USD for the smallest plant of 50 Mcf per day to 5 mill USD for the 1 500 Mcf per day[91]. Operating costs are related to possible pre-treatment of H_2S, disposal of water, power on-site and rental of the feed compressor. According to the supplier, payback time can vary from 1 for a large plant (3 000 Mcf per day) to 4 years (1 000 Mcf per day), however, with recent price increases in methanol in the United States the payback period has been reduced to 2.5 years for 200,000 scfd on a gas flare in North Dakota.

Oberon fuels / Acme GasCo[92]

OBERON FUELS is developing modular, skid mounted DME unit, targeting small natural gas and/or biogas sources. The smallest unit, it is the BNG-4.5 that can process 125 Mcf per day of pipeline specifications natural gas which yields 4 500 gallons / day of Partial BioDME and 13.63 mt of methanol[93].

The company partnered with Acme GasCo, an oil and gas operator, to enable the technology at a remote natural gas field in the Marcellus Shale. This stranded gas was useless to Acme GasCo until it took advantage of Oberon Fuels' easily deployed DME production facilities. The facility uses the stranded gas as feedstock to produce 10 000 gallons of DME per day.

Acme GasCo is now able to monetize its stranded gas by transporting the DME out of the natural gas field in propane-style tanker trailers. The tankers move the DME to potential customers, like local heavy duty diesel fleets converted to DME as well as commodity markets that are up to 200 – 500 miles away.

Theoretical examples

Global Forum Flaring Reduction and Gas Utilization: Mini Methanol Plant[94]

This presentation on the potential of mini scale plants of Methanol in the Niger Delta is a good example of capturing and maximizing value from remote wells where gas gathering systems costs is substantial or difficult. There are hundreds of associated gas sources from fields in the area, easily wasting 4 000 Mcf per day of raw natural gas each, which could support a 100 tonne/day methanol production plant.

The projects proposes mini-methanol 25-100 tpd plants to handle associated gas of 80% methane content and maximum of 10ppm(v) of sulfur. The plant includes desulfurization, catalytic steam/hydrocarbon reforming, heat recovery from process gas, synthesis gas compression, synthesis gas distillation and methanol synthesis loops and off-sites. It consumes natural gas, raw water, nitrogen and electrical power. It requires ~ 37 Mcf/mt nh3, plus nitrogen, raw water and electrical power.

They project large scale facilities with a capital cost of 291 USD/tpa and operating cost of 0.223 USD/gallon. The mini scale facility is expected to be cheaper, with a capital cost around 80 USD/ton and capital cost of 0.128 USD/gallon.

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[88] GasTechno, "http://www.gastechno.com
[89] GLOBAL METHANE INITIATIVE, "Gas Monetization via Emerging "mini-GTL" Options – Middle East Meeting, Dr. Theo H Fleisch," Washington, October 2-3, 2012
[90] http://www.gastechno.com/pdf/GasTechno-Mini-GTL-Data-Sheeet.pdf
[91] http://www.flaringreductionforum.org/downloads/Breidenstein.pdf
[92] http://www.oberonfuels.com/products/production-units/
[93] One metric ton of methanol (2,204.62 lbs) = Approximately 333 U.S. gallons
[94] World Bank Tata Messiri Senior Special Assistant (DTSG/OPTS Initiative), "Mini Methanol Plant

4.6 Mini-LNG

Pilot, demonstration or commercial projects and suppliers

GE Oil and Gas "LNG in A Box™"[95]

GE offers the "LNG in a Box" unit, which it is a modular, small, rapidly (re)deployable gas liquefaction unit that can handle lean gas from pipeline or gas gathering systems. The technology can use simple methane or nitrogen refrigeration cycles. The unit can be designed to deliver 10-50 k gallons per day of LNG with a gas recovery of 80-82%. That would require approximately between 1 000 and 5 000 Mcf per day of dry lean natural gas. Operational expenses are low, since the unit it is highly automatize, operating with a specific power consumption of 1.4 kWh / gal (1.3MJ / l). Up till now, there has been more than 40 sales inquiries and at least 10 customer follow ups. Lead time is expected to be 6-12 month.

Expansion Energy / Dresser Rand Co. "LNGo" "Mobile LNGTM" [96,97]

Expansion Energy, through Dresser-Rand Co., develops cost-effective, trailer-mounted or skid-mounted, small-scale production of 2.5 tonnes of LNG a day (1 500 gallons per day) at high- and low-pressure natural gas pipelines and local gas distribution lines, in "stranded" oil & gas fields and for associated gas waste stream. It uses its own technology (VX Cycle), based on a methane expansion cycle, and Dresser-Rand components like compressors and gas engine gen-sets. The unit operates under ambient temperature (-40° F to 110° F), uses waste heat and cold and yields a gas-to-LNG conversion efficiency of ~70% for the 6 000 gallons per day plant, which it is the only commercially available at the time of the report. That would require around 200 Mcf per day of pipeline specifications natural gas, or 200-300 Mcf per day of associated gas as feed for the upcoming 1 500 gallons plant. The unit produces its own power, it is fully automatized and requires no continuous labor or separate inputs or refrigerants. They offer an optional package for separation of NGLs (propane, butane, etc.) from the feed gas. They claim low capital and operating costs (full-service maintenance and repair programs), highlighting that the use of multiple modules ensures a higher % of uptime and lower capital risk. Deliveries are expected within several months from the order.

Wuhan Sanjiang Imp.& Exp. Co., Ltd.[98]

Wuhan Sanjiang Co. is Chinese supplier that offers small scale (20 000 ~ 300 000 Nm3/day) LNG plants. They include personalized pretreatment (LPG separation, pressure regulating and metering, and pretreatment denitrification can be realized), purification (de-acidification, de-sulfurization, de-hydration and benzene removal of feed gas), compression (reciprocating), liquefaction (mixed refrigerant process for LNG) and storage modules. In total, a set of 11 skids of flatbed trailer are needed. The main products are liquefied natural gas (LNG) and some byproducts: liquefied petroleum gas (LPG) and heavy hydrocarbons etc. For the smallest unit we can consider a minimum input of ~1 000 Mcf per day. Capital costs are expected to be in the range of 500 to 1 500 USD/Mcf per day. Operating cost would include liquefaction running costs 0.17 USD/Mcf and 0.78 kWh/Mcf, which if applying an electricity cost of 0.1 USD/kwh, it would be 0.078 USD/Mcf. Since the product is supplied overseas it is expected that no maintenance support is provided, and therefore, significant O&M could be expected. The pay-back period estimated by the supplier is in the range of 2 to 6 years.

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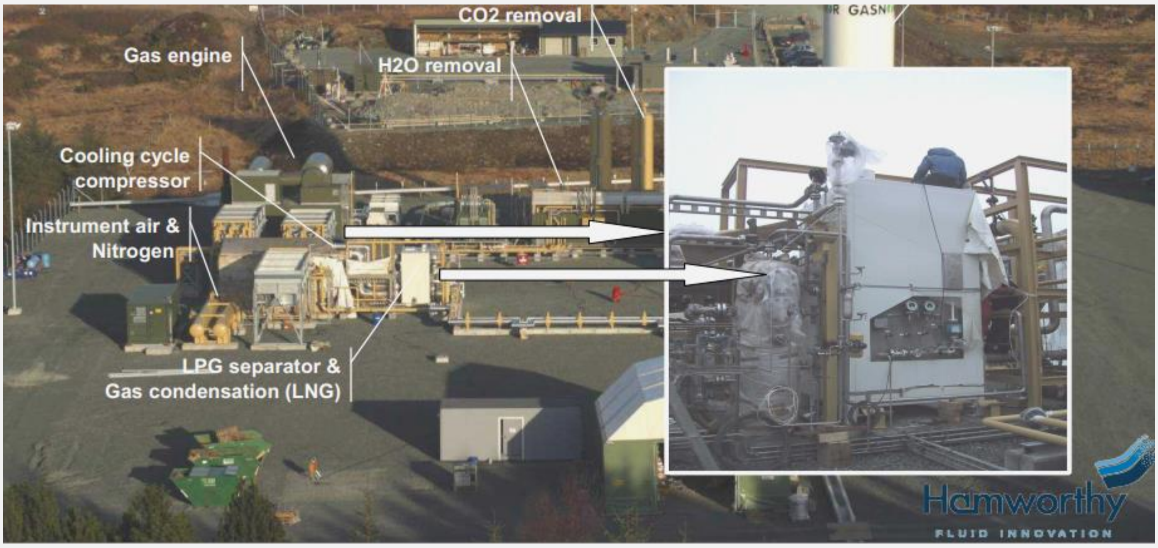
[95] *GE Oil and Gas, "Accelerating Adoption of LNG fuelling infrastructure,"*
[96] *Dresser Rand / Expansion Energy, http://www.expansion-energy.com/vx_cycle_for_small-scale_production_of_liquefied_natural_gas_lng.*
[97] *Expansion Energy, http://www.expansion-energy.com/yahoo_site_admin/assets/docs/Expansion_Energy_LLC_-_VX_Cycle_Overview_PPT.295115525.pdf*
[98] *Wuhan Sanjiang, "http://cnsanjiang.en.alibaba.com/product/551654545-214174856/Small_LNG_plant_Modular_movable_LNG_plant.html," Wuhan Sanjiang*

Wartsila / Hamworthy[99]

Wartsila Hamworthly was one of the pioneers of small scale LNG plant back in 2003. The client was Gasnor of Norway. The liquefaction unit was designed to handle a minimum of 3 000 Mcf per day of pipeline specification natural gas to yield around 60 LNG tonnes a day. The system can be turned down towards 0 without affecting the product. It runs unmanned with minimum need for inspection outside maintenance schedules. Start up from warm condition is done by one man in three hours. It also showed good performance under harsh climate conditions. The company has been refining its concept through the period 2008-2012, including full performance tests, pilot on gas carriers and automated operations, and now it can deliver production capacities below 50 tonnes per day.

Figure 10: Items of the mini-LNG plant installed in Norway. Source: Hamworthy



Its New MR technology uses a mixed refrigerant in combination with standard equipment (pretreatment, engines, heat exchangers) to achieve low investment costs and fast manufacture of a modular, portable liquefaction unit. Two plants were under construction during 2013. Technology is not mature enough, but it is commercially available and proven extensively.

Technical

- Pressure and volume
  - It needs at least 20 bar pressure and a buffer is usually welcome[100]. Feed gas compression may be needed then.
  - The smallest unit is 250 Mcf per day and the largest unit is 1 200 Mcf per day.
  - Dimensioning: Not doing the dimensioning of the peak (2 000 Mcf per day), but of the average or valleys, or even better, or after one year volumes 300 Mcf per day.
  - Downturn: Plant can works 40-100% of the capacity, however going below 40% hurts performance, and volumes around 10% force the shut-down of the plant.
- Heating value and HC content
  - NGL recovery is needed
  - Alternatively Gas Steam reforming unit which can bring NGLs to methane, and then liquefy them
  - However, the unit can tolerate all HC, except C10+ (Wax and clog, especially in cold weather), the problem is not technical, but it is commercial, client wants standard LNG quality
- Impurities
  - Pretreatment for flare gas should include dehydration, and removal of H2S, aromatics, H2O, CO_2, O2, N2 and NGLs. Pretreatment is off-the-shelf and very gas source specific, some of the pretreatment techniques (Batch, amine, mol sieve, CO2, wash and membrane technology)
    - CO2 50ppm max, even though it can handle variations on the CO2 inlet concentrations (CO2 scrubbing /polish is effective)
    - H2O 1ppm
    - H2S 4 ppm. This is key and it can bring the cost up
- Operations
  - System is very robust. Reliability is high, 96%, the demo plant has been shut down 65 times with no major issues. Start-up time is 3-4 hours.
  - Operations are fully –automatized and unmanned, but daily supervision is required by trained personnel from the O&G operator. Annually service stop.

Procurement/Geo

- It is small but not completely portable, it requires foundation, pipeline cut, wiring and rewelding. It is not plug and play. It requires coordination and expertise, so it is recommended to keep the plant for 3-5 years, and not to move it every six months.

- They serve EU, and equipment it is EU validated. However, they can supply US, but that would require technology validation and import/export duties, as well as special service agreements/contracts.
- Delivery time is 11 months within Europe

Commercial

- Leasing and renting may be an option in the future, but is not currently offered…
- CAPEX for the pretreatment part it is highly gas source specific, and can vary a lot depending on gas composition. The liquefaction plant is around 6.5 mill USD/ 1 000 msfcd. Electrical power is the main capital expenses when the gas is assumed to be for free. Energy consumption is between 0.5 to 1 kWh / kgLNG, 0.7 on average. Usually rest of Opex cost it is as little as 5% of the electrical power cost, depending on electricity price. The pay-back period is highly dependent on the feed gas price, LNG price and electricity price. Investment pay-back it is in general a secondary item.
- General overview is that it would be difficult to be proven economically feasible on a scenario with low LNG price and high electricity price. With time, cost will go down for the investment, but still operations are the key

Cryostar[101]

Based on its experience with the boil off gas re-liquefaction system onboard LNG carriers, Cryostar now offers small scale LNG or LBG plants for onshore natural gas or biogas liquefaction application with capacity from 5 to 400 tons per day (minimum input of 250 Mcf per day).

Theoretical example

Lantau Group Consultancy: High-level Cost Assumptions for Small Scale Onshore LNG[102]

Lantau group suggests a cost of small scale onshore liquefaction unit of 2 000 USD/tpa and around 10 000 – 15 000 USD/Mcf per day under our estimations. They assume operational cost for the plant of 2% capital expenses or 0.75 USD/Mcf. Storage cost estimation, including 10 days of back-up storage, is 1 500 USD/scm3 with operational expenses of 2.2 USD/Mcf. They also include trailer capital investment of about 0.5 mill USD or 0.70 USD/mmbtu, with operational expenses around 0.50 USD/Mcf. Other costs includes vaporization 1 USD/Mcf and overheads and marketing 0.75 USD/Mcf. Final cost of the LNG product would be around 11 USD/Mcf.

[99] *wartsila, "http://www.wartsila.com/en/gas-systems/LNG-handling/LNG-liquefaction,"*
[100] *Considering that 1 tonne of LNG is ~ 50 mscf*
[101] *Cryostar, http://www.cryostar.com/pdf/dnl-zone/small-scale-liquefaction.pdf*
[102] *Lantau Group - Nel Semple, "Pricing of LNG from Small Scale Facilities - Some Examples from Indonesia and Thailand," 2012.*

4.7 Mini-GTL FT

Pilot, demonstration or commercial projects and suppliers

COMPACTGTL[103]

CompactGTL was founded through private equity investment in 2006, with the aim of commercialising small scale GTL technology. It is currently the first fully working modular Gas-to-liquids Fischer-Tropsch (GTL-FT) technology in the market, backed by an IP patent portfolio. The technology has been fully operational in a demo plant for Petróleo Brasileiro S.A. since 2010. It is a technology that it is qualified, modular, functional, and approved by a commercial pilot. CompactGTL supplies flexible, process-intensified (catalyst placed on metal sheet inserts with effective heat transfer), mini-channel reactor technology for both the reformer and the FT unit to operate in a complete, modular GTL technology. CompactGTL acts as a complete solution provider, acting as the central hub of the project development process, including heading up supply chain management, FEED, project management and execution through an extensive team (+50 employees) headquartered in Oxfordshire, UK.

The process follows these steps:

1. Feed can be untreated raw gas: A minimum of ~ 400 psi is needed, so in the case of gas coming from Low pressure separators and treaters in tight oil operations, it would be needed to have a feed gas compression system. The CompactGTL plant encompasses readily available, 3rd party gas treatment packages that remove common impurities like H2S, Cl2, Hg and heavy metals.
2. NGL recovery: Preferably, a NGL recovery unit is included, to drop most of the liquids (C3+ and partially ethane) and get the most value out of the feedstock. If there is no NGL removal, the pre-reforming unit will have to convert all C2+ into methane, which a highly inefficient use of rich gas feeds.
3. Pre-reforming unit: The pre-reforming unit will convert the rest of the ethane into methane and it will act as a buffer system, if sized correctly. This step makes the process much more stable and robust.
4. SMR unit: The Steam methane reforming unit will produce syngas to feed the FT unit.
5. FT unit: The previous unit and the FT unit work together to optimize the process, including minimizing waste streams.
6. Delivery: The final syncrude product (API 40-50) can be blended in small quantities into the oil crude. It can also be upgraded to diesel on site with off-the-shelf packages.

Robustness of the technology is a key item, and a lot of effort has been put to increase it. The demo plant has shown a 90% reliability and new plants are expected to run on average at 95% uptime and up to 99%. Part of these improvement is due to the generic nature of the modules. Different modules, like the catalyst, can be taken out and replaced by new ones with minimum interruption of the plant.

Unit Scale for standalone commercial plants range from 5 000 Mcf per day to 150 000 Mcf per day, with minimum train size of 2 000 Mcf per day and minimum economic cutoff of at approximately 10 000 Mcf per day. The feed:output ratio is 10Mcf/bpd of syncrude. The technology would only be feasible for a huge multi-well pad development, and most probably, after a Gas Processing Plant, but it is definitely not suitable for a single tight oil well.

Right now they are engaged in commercial efforts and evaluating project feasibility for a number of oil and gas majors worldwide. The targets of the technology are remote, large oil fields with substantial amounts of associated gas, which might be flared. These sites usually present very large cost of infrastructure development to handle the associated gas and place it to markets. Project cost for the Compact GTL unit is around 100 000 USD/barrel capacity installed. This is equivalent to 10 000 USD/Mcf per day. Upgrading syncrude to diesel, would add between 10-15% to the final investment. Economics of blending and diesel upgrading must be checked upfront towards wax content, weather conditions and flow assurance. OPEX is around 18 USD/barrel, including all refurbishing, catalyst changeout, labour, maintenance and royalties. Operational expenses per barrel go up as unit size goes down. Lead time for EPC is usually 18-24 months for smaller unit, and up to 36 months to larger plants. This technology can make use of this low value gas and enhance its value considerably. However, economies are extremely project-specific, with important variables being the local fiscal regime, the rules and production sharing agreements, and existing infrastructures.

VELOCYS / OXFORD CATALYST[104]

Velocys supplies with modular distributed GTL technology based on highly compact, skid-mounted, FT micro-channel reactors. The technology it is based on particulate catalyst in small channel and cross-flow coolant water/steam generation. The miniaturization of the GTL technology actually presents some advantages, like increase on robustness, thermal stability and volumetric productivity. Commercial plant designs range from 5 000 to 150 000 Mcf per day of dry natural gas input, equivalent to 500 to 15 000 bpd of liquids,

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[103] *http://www.compactgtl.com*
[104] *http://www.oxfordcatalysts.com/press/egs/gtl_adds_value_to_gas_production_2011-04.pdf*

producing a mix of 85% diesel and 15% naphtha[105]. Their modules can be linked together in parallel to increase production and can be deployed in remote areas with a construction time between 18 - 24 months. This technology has been tested by several O&G operators in the period 2010 – 2012. They have sold at least 10 FT reactors so far, including an order from Rosneft for a 100 bpd unit for a refinery in Siberia. Also, the company is running 3 demonstration projects (< 1 000 mcfd) in Brazil, Austria and the USA, where interest from shale gas developments has been shown.
Capital expenses are around 10 000 USD per Mcf per day or 100 000 USD per bpd for a 20 000 – 25 000 Mcf per day input of dry natural gas and 2 000 to 2 500 barrels of synthetic crude oil a day plant. Operating cost are about $1.5 to $2.5 per Mcf or $15 to $25 barrel of liquids.

VERDIS[106]

Verdis supplies a truck-deployable FT-based unit using a patented catalyst. Minimum capacity is 250 scf/day for the smallest unit, which will produce 12.5 barrels, or nearly 2 000 litres of market-ready, zero-sulfur, zero-aromatics diesel per day, worth around 3 060 USD a day, or 1 116 900 USD a year. Operational expenses are mostly linked to the catalyst, which must be replaced approximately once a year. They are getting ready deployable equipment for lease, targeted at smaller consumers with gas deposits which are uneconomic by conventional means, or those with only occasional gas-flaring needs.

METHION[107]

Methion supplies a GTL unit based on their Methane Sulfonic Acid (MSA) process which burns methane in sulfur trioxide with no oxygen requirements. The smallest unit is a small footprint, modular design, easy to implement 200 Mcf / day unit that can handle short term Associated Gas production swings up and downs without adverse consequences. It can handle associated gas with minimum gas treatment: H_2S, high CO_2, high N_2, H_2, and condensates without pretreatment. It can also be scaled up and down to meet the gas profile.

[105] *http://www.oxfordcatalysts.com/press/ppt/CERAWeek%20Mar%202013.pdf*
[106] *http://www.verdisfuels.com*
[107] *http://www.methion.com*

4.8 Ammonia Production

Pilot, demonstration or commercial projects and suppliers

Beowulf Energy LLC ("Beowulf") & Beowulf N-Flex [108]

Beowulf N-Flex N-Flex supplier small-scale mobile NGL recovery and anhydrous ammonia production units. They use their NGL recovery unit to provide lean gas to the Haber Bosch process, which it is based on known-suppliers components, fully automatized and optimized for small scale and flexible feedstock. The ammonia production uses the light hydrocarbons after NGL knockout, and a methane/ethane mix at optimal ratio for the N-Flex intake. Gas is provided to power onsite for compressors and rest of utilities. The unit "Micro N-Flex" is a mobile, skid-mounted unit capable of producing 1 100 tons per year and handling around 50 - 100 Mcf per day. They also offer a larger unit, the "Mini N-Flex" producing up to 22 000 tons per year, of which three of them are currently in operation. They also offer a lease option including equipment and management of the NGL and ammonia production.

Theoretical examples

End-Use Technology Study by NTEL and NDPA [109]

This study modelled a small scale ammonia plant including gas clean up, (sulfur and carbon dioxide removal), hydrogen production and purification, nitrogen generation and ammonia synthesis[110]. Three cases studies were presented, ranging from 300 Mcf per day to 2 000 Mcf per day. The results show an estimated capital costs of 25 000 – 100 000 USD/Mcf per day, with product cost of 300 – 500 USD/ton of Ammonia, leaving an expected marginal profit for ammonia of 100 - 200 USD/ton. Revenues per input could be considered 10 - 25 USD/Mcf per day.

Economics of Using Flared vs. Conventional Natural Gas to Produce Nitrogen Fertilizer: A Feasibility Analysis[111]

This study is focused on the reduction of flaring in North Dakota, connected to tight oil flaring. It proposes an Ammonia Plant of 3 400 tons per year capacity, which it is estimated to handle 200 - 300 Mcf per day. Ammonia costs are expected to be around 300 USD/ton for very large plants and close to 1 000 USD/ton for small scale plants. That cost it is distributed between capital costs (73%), natural gas (17%), electricity (6%) and Operations and Maintenance (4%). In the case of associated gas utilization the cost of natural gas can be consider zero of there is no gas gathering pipeline already in place.

Hydrogen from Steam-Methane Reforming with CO_2 capture [112]

The authors simulated a steam reforming process with ASPEN software. The plant, expected to handle 50 000 mcsfd with an efficiency between 78% - 84% and availability of 95%.
Investment would be around 80 mill USD, including supplies and 30 mill USD on direct capital cost. Operating and maintenance costs (without supplies) are expected to be between 0.5-1 USD/MMbtu. Emissions of CO_2 to the atmosphere are expected to be 0.027 tons CO_2 /Mcf.

[108] *NETL, North Dakota Industrial Commission and EERC, "End-Use Technology Study – An assessment of alternative uses for associated gas*
[109] *NETL, North Dakota Industrial Commission and EERC, "End-Use Technology Study – An assessment of alternative uses for associated gas*
[110] *The model, using Aspen Plus software, was optimized based on an input of 936 mscfd of raw gas with a composition of 52% methane, 36% carbon dioxide, and the remainder being nitrogen, oxygen, and trace amounts of sulfur compounds.*
[111] *M. T. e. a. D. o. A. a. A. E. A. E. S. N. D. S. University, "Economics of Using Flared vs. Conventional Natural Gas to Produce Nitrogen Fertilizer: A Feasibility Study," Agribusiness & Applied Economics 699, September 2012.*
[112] *John C. Molburg and Richard D.Doctor, "Hydrogen from Steam-Methane Reforming with CO2 capture," in 20th Annual International Pittsburgh Coal Conference, Pittsburgh, 2003*

Appendix 4: Economic Cost Model

The model developed is intended to simulate and compare gas utilization options for any oil field with associated gas, including unconventional gas, based on production profiles and well planning. The next workflow showcases the different categories/types of sheets in the model and their interaction:

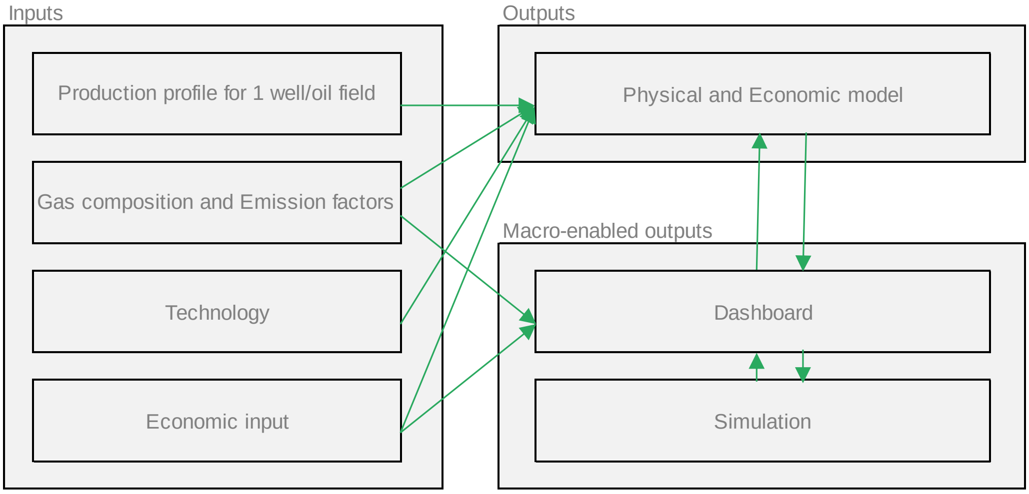
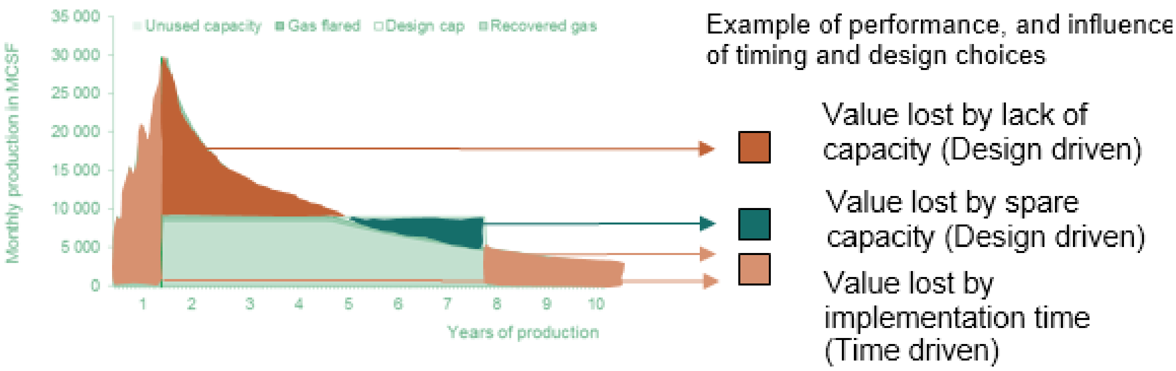


Figure 11: Structure of the Carbon Limits model

The final objective of the model is to understand both key indicators of the implementation of different gas utilization technologies and the influence of timing and design choices (Figure 2). Key output include IRR, NPV, emission reduction, and abatement cost.

Figure 12 Representation of gas volume lost due to timing and design choices.



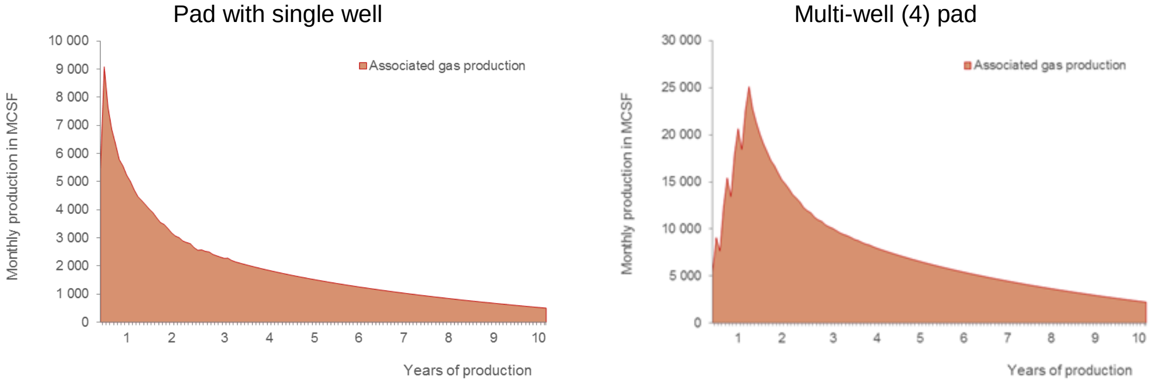
3.1 Production Profile – input

Historical well data from North Dakota was used to construct typical well production profile for the model. The information used contains oil and gas production profiles and share of gas sold and flared for all tight oil wells drilled during the period 2010-2013 (That includes 3-year records for 1,350 wells, 2-year records for 2,268 wells and 1-year records for 3,841 wells). We also include average data for first month of production (5,360 wells). Forecast is extrapolated based on this data and verified with commercial research. The average number of wells per pad in North Dakota is around 4[113]. Therefore, we have established a multi-well pad scenario with 4 well where each well comes online three months

[113] *The Bakken moves to pad drilling. Unconventional Oil and Gas Center. 31th July 2013. http://www.ugcenter.com/bakken-moves-pad-drilling-617211.*

after the previous one. In theory, a new well can be completed within 30-40 days, but due to rig availability, project planning, outsourcing, permitting, and financing, a 90 days gap is considered realistic.

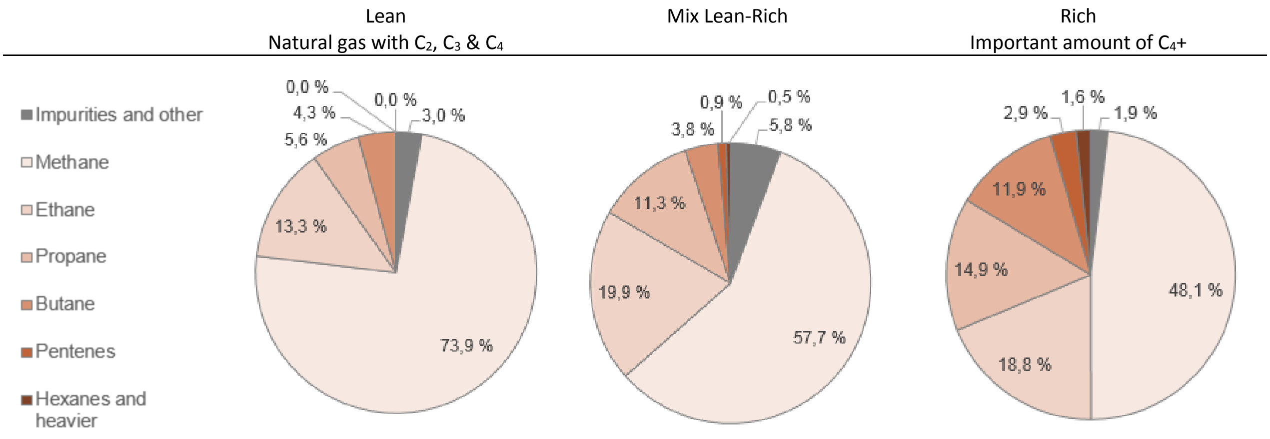
Figure 13: North Dakota production profiles used in the model.



3.2 Gas Composition – input

Regarding gas composition, we have used an average gas composition in Bakken based on 7 samples reported by NDIC and EERC[114]. For sensitivity purposes we have also applied two other gas composition, a lean mix and a very rich mix, both from the previous reference. Methodology used for calculating associated gas properties is AGA (8 – 1994). Emission factors used for the gas is based on the carbon content and EPA emission factors of each component. The global warming potential assumed for methane was 25 $kgCO_{2eq}$/kg methane.

Figure 14 : Typical gas composition, used for the simulations



	Lean	Mix Lean-Rich	Rich
Density	0,9356 kg /m³	1,0729 kg/m³	1,3235 kg/m³
HHV	1 275 Btu/scf	1 513 Btu/scf	2 095 Btu/scf
GPM	2,98 gal C_3+ /mscf	4,9 gal C_3+ / mscf	9,6 gal C_3+ / mscf
EF	2,032 $kgCO_2$/cm	2,32 $kgCO_2$/cm	3,02 $kgCO_2$/cm

[114] *End-use Technology Study – An Assessment of alternative uses for associated gas. North Dakota Industrial Commission (NDIC).*

3.3 Technologies

The following table list the main assumptions taken for the different technologies:

Pipeline	• It is assumed that the well is connected to the gathering network at the end of the second year of operations • Expected remaining flaring due to unsolved issues with the gathering system after pipeline connection: 10%. However, this parameters does not affect the main results, only those sensitivity cases where project lifetime is extended beyond.
Flare system	• Base case assumption: Stack flare, efficiency : 98,5% • Sensitivity (low): Ground flare, low efficiency (96%) • Sensitivity (high): Stack flare, high efficiency (99,75%)
Pre-treatment	• It is assumed that pre-treatment remove 100% of the CO_2, H_2S, N_2 and H_2O of the associated gas stream • It is assumed to be installed regardless of the technology implemented. Costs are embedded in CAPEX for each utilisation options.
CNG trucking	• It is assumed compression of all methane, ethane, propane and butane. C_5+ drops out and are blended with the oil • Distance to CNG delivery is not modeled. Delivery is assumed to be within 25 miles. Costs are included as O&M cost or service fees in the renting option.
NGL recovery (C_3+)	• It is assumed that 60% of the propane and butanes and 80% of the heavier components (C_5+) are recovered. • Rest of the gas is flared • Assumed a NGL storage tank with a cost of 80 000 USD • Distance to NGL markets is not modeled. NGL price is “at the wellhead”
NGL recovery (C_5+)	• It is assumed that 80% of the heavier components (C_5+) are recovered • Assumed a NGL storage tank with a cost of 80 000 USD • Distance to NGL markets is not modeled. NGL price is “at the wellhead” • Rest of the gas is flared.
Gas powered Gen-set using lean gas **Reciprocating engine** **Gas powered Micro-turbine using lean gas**	• Estimated power needs per day are based on the report technology reviews and are function of the volumes produced • Around 0.2 MW installed per well and 2.4 MWh used per day. • Associated gas in the fuel blend (input) is assumed to be 80%, which it is the upper limit for using associated gas in an engine that accommodates associated gas. • Well availability can be as low as 60 - 80 %, leaving some hours or days with no power demand, this is similar to the working hours we get in the model. • Efficiency of the engines 28%

3.4 Economic Inputs

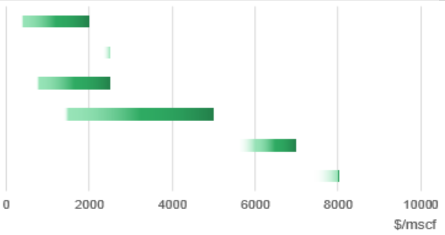
Main economic assumptions (Components price)[115]:

	$/mscf
Pipeline quality dry gas	3.6
Rich AG at the wellhead	4
Rich CNG, compressed associated gas	5.28-7.85
CNG (on @spec) for gas turbines	9
Diesel price (3 USD/gal). Estimation of value	32
Per component	
C_1	3.6
C_2	6.6
C_3	14.1
IC_4	18.9
NC_4	19.4
IC_5	80.0
NC_5	80.3
C_6+	103.7

Technologies costs assumptions are based on benchmarks created for this study combining existing cases studies and information provided by suppliers through interviews. CNG and C_5+ NGL recovery are the lowest investments since CNG trucks are supposed to recover a substantial part of its value at the end of the project and C_5+ recovery systems are mostly mechanical devices. That it is why the estimated operational expenses are very low for the C_5+ NGL recovery. Gas to power operational expenses assumption are higher due to the maintenance and operation costs. Gas to power can generate substantial revenues related to fuel savings substituting diesel by associated gas. If the well is connected to the grid, power savings can also lead to significant savings considering a current power price of 7.83 cents USD/kWh in North Dakota[116].

The following table presents the assumptions applied in the model.

		Estimated CAPEX range ($/mscf)	Estimated OPEX ($/mscf)	Est. Fuel savings ($/mscf)	Power savings ($/mscf)
CNG trucking			0.8		
NGL recovery C3+			0.2		
NGL recovery C5+			0.5		
Gas to power	Gas turbine		1.1	9	23
	Reciprocating		0.9	32	23
	Micro-turbine		1.7	9	23



Renting is available for CNG trucking, based on quotes from one of the key suppliers. Small fields would pay a higher fee per volume (up to 4.67 USD/Mscf), which it is close to the price paid at the GPP (~5 USD/Mscf). Larger sites would have a smaller fee per volume (1.56 USD/Mscf), allowing for substantial gains on multi-well pads. Any size would have to pay a daily fee of 700 USD/day, regardless of the volume. There is no available renting fees on the literature or they were not disclosed within conversations with suppliers. Our estimation is between 330 and 900 USD/day. C_5+ and the C_3+ NGL recovery units were estimated at 400 and 600 USD/day respectively. Finally, it was assumed that

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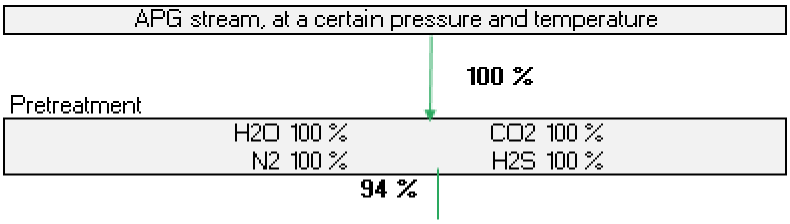
[115] *Data combined from EIA, OGJ (Oil and gas journal), suppliers interviews and CL estimations.*
[116] EIA

renting power units costs around 200 USD/day, including maintenance. This is based on literature and quotes from suppliers.

3.5 Physical and Economic Model

The physical model assumes that there is an available associated gas stream at a certain pressure and temperature. This stream goes through a pretreatment where, as stated, before, unwanted components are withdrawn.

Figure 15: Physical model for the pretreatment phase



After that the associated gas is supposed to go into a gas gathering system or gas pipeline available. Then, the different gas utilization technologies play a role on minimizing gas flaring. The simplified diagram for process-based technologies (CNG and NGL recovery) assumes that there is an initial stream of gas without impurities entering into the process. CNG would sell its 1st stream (off-spec CNG) as the main product, while blending the 2nd stream (C_5+) with the crude. NGL recovery options would recover the NGLs (C_3+ or C_5+) as 1st stream, and flare the 2nd stream (leaner gas). In case of combustion-based technologies (gas-to-power), the gas would be used to power the field needs, but since they are usually small, normally there is remaining flaring. The model is able to work with technologies in parallel and series (called "2nd Technology" streams), although this level of complexity has not been used in this analysis.

Figure 16: Physical model for technology applications