

**Natural Gas Flare Reduction:
Case Studies in Russia, Nigeria, and the United States**

Stella Cao

Michael Oristaglio and Brian Skinner

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Stella Cao, 30 April 2014

Abstract

Today about 150 billion cubic meters of natural gas are flared every year at oil wells around the world. This combustion of natural gas associated with oil production is a waste of a useful energy source and also accounts for about 2% of total anthropogenic emissions of carbon dioxide into the atmosphere (GE, 2011). Carbon dioxide is a potent greenhouse gas that absorbs outgoing radiation, increasing the Earth's energy budget. By using associated natural gas as an energy source instead of flaring, global natural gas supply can be conserved at a time when increase in the demand for natural gas is outpacing demand for other fossil fuels. Given the role of natural gas in fueling electricity generation and transportation, understanding how to utilize associated natural gas will provide insight into limits on natural gas infrastructure. Although the pipelines available to transport oil from wells are not compatible with transporting natural gas, technologies such as liquefied natural gas (LNG), combined cycle gas turbines (CCGT) for electricity and heat generation for use near the wellsite, enhanced oil recovery (EOR), and gas to liquid (GTL) are all possible alternatives for the use of associated natural gas.

Consideration of these technologies for specific oil-producing regions in Russia, Nigeria, and the United States illustrates the relative merits of each form of flaring mitigation. Evaluation of techniques to reduce flaring for these case studies shows that the interplay of enforced regulation, increased natural gas demand, higher natural gas prices and social stability can provide strong incentives for long-term investment in more widespread natural gas infrastructure.

Introduction

Natural gas produced as a byproduct of oil extraction is often dealt with by combustion and emission into the atmosphere, a process called flaring. Flaring is common at oil wells and is a persistent global problem. The total volume of natural gas flared annually at well sites around the world is estimated at about 150 billion cubic meters (bcm), or roughly 5% of global natural gas production (GE, 2011). In terms of energy, this volume is equivalent to wasting about 2.4 million barrels of oil per day, or about 3% of world oil demand in 2013. Flared natural gas not only wastes an economic resource, but also has a large environmental footprint. Carbon dioxide from flaring natural gas constituted about 2% of total manmade CO₂ emissions, releasing about 400 million tonnes of carbon dioxide to the atmosphere in 2011 (GE, 2011). Unless addressed, this problem is likely to continue to grow with increased oil production, which is expected to

grow from about 90 million barrels per day in 2012 to nearly 110 million barrels per day by 2035 according to the BP Energy Outlook (BP, 2014).

World use of natural gas itself is projected to increase at a rate outpacing coal and oil, as it replaces coal for electricity generation and oil for heating and transportation. Natural gas will overtake oil as the dominant fuel in Organisation for Economic Co-operation and Development (OECD) countries by 2031 and will have a 24% share of primary energy in non-OECD countries by 2035 (BP, 2014). And yet flaring persists even with growing demand. Lack of adequate infrastructure in both OECD and Non-OECD countries for handling natural gas at sites where it is a byproduct of oil production creates stranded gas in oil producing regions. Existing infrastructure for handling oil at a well site and transporting it to markets is not necessarily compatible with handling and transporting natural gas. Flaring signifies a mismatch between supply and demand in the global natural gas market.

Because of expensive investment costs, the petroleum industry internalizes risk on oil production under a calculated expectation that oil prices will continue to rise. Oil prices from the two major global indices (WTI and Brent) have been on a more stable trend than natural gas prices at the benchmark US (Henry Hub), Canada (Alberta) and UK (NBP) indices even though some natural gas prices are linked to oil prices in long-term contracts.¹ In terms of investment, oil production is generally less risky than natural gas production. There are plenty of risks associated with oil exploration: however, by the time production starts, oil transportation facilities, such as pipelines, are in place. Existing oil pipelines, infrastructure and high oil prices have been incentives for investment in oil for many years, whereas investment in natural gas, with an immature infrastructure and volatile prices, often faces delays.

Flaring natural gas for emergency shutdowns, non-planned maintenance, or disruption of the processing system is allowed to occur for safety. For example, to maintain safe wellhead pressure at the extraction site, it may be necessary at times to flare associated gas. Alternatively, associated gas is vented when the operator does not have the equipment to flare the gas or the economic incentive to process it for flaring. During venting impurities that would have been removed before flaring such as sulfites, volatile organic compounds (VOCs), carbon dioxide, and methane are all emitted directly into the atmosphere. Venting is generally considered

¹ The current trend is to decouple from oil prices and price natural gas based on short-term hub indices. However, natural gas long-term contracts with Russia and other major producers will not expire in the near future and have a large proportion of its price linked to oil.

unacceptable environmentally, in part because methane is a much more potent greenhouse gas than the carbon dioxide and water released by flaring. While tracing venting is nearly impossible and not practiced, flaring is under international monitoring. On a voluntary basis, nations can enter the Global Gas Flaring Reduction Partnership (GGFR), which was created by the World Bank after the Kyoto Protocol in 2002. The GGFR is a public private partnership that supports efforts to utilize associated gas in oil producing nations and mitigate flaring.

Associated natural gas can of course be utilized for its energy instead of being flared. The opportunity cost of flaring is the loss of revenue from selling natural gas and natural gas liquids. Capturing associated gas increases natural gas supply, which means that the rate of exploring and extracting natural gas in new fields could be reduced. Natural gas supply in the United States has been increasing strongly - a phenomenon sometimes called the natural gas revolution, or shale gas revolution, because it is driven largely by a large increase in production from unconventional shale reservoirs. However the rising supply from the U.S is insufficient to meet the expected increase in worldwide demand. Worldwide demand for natural gas will increase from 8.5 bcm per day in 2012 to 14.1 bcm per day by 2035(BP, 2014). Approaches to meet these demands include: developing new natural gas fields, increasing efficiency in natural gas, or utilizing associated gas. The last option can be realized through new infrastructure for transporting natural gas or new technologies for processing natural gas at or near the well site.

Methods for mitigating natural gas flaring rely not only on improving infrastructure for natural gas transport with oil transport, but also on new technologies that can transform gas into liquid. Gas to liquid (GTL) technology converts natural gas into liquid hydrocarbons identical to products distilled from crude oil. After GTL, the liquid hydrocarbon can be transported through the same pipelines and substitute for crude oil products or used directly in motor vehicles. GTL technology removes the need to build new natural gas pipelines, or to open a new natural gas trading hub. Although the standard chemical process of GTL conversion is well understood, this technology has its own environmental and energy demands and is currently still in the developmental stage as an economic large-scale solution to flaring at well sites. Other alternatives to flaring include: traditional pipeline transfer, use of natural gas in enhanced oil recovery (EOR), in electricity generation at or near the well site, in processing for natural gas

liquid (NGL) products² and conversion to liquefied natural gas (LNG) for easier transport by ship.

This paper starts with a brief review of different options for handling associated natural gas, including flaring and its environmental consequences. It then treats three regional cases in which technologies for mitigating flaring might be applied in different geologic, economic and social settings: from the world's largest natural gas producing region in Western Siberia, Russia, to the world's most notorious flaring region in Nigeria, to unconventional oil shale plays in the Bakken region of North Dakota. Each case study will be discussed in terms of current flaring conditions, petroleum geology, associated gas utilization approaches, and regional environmental impact. If mitigation techniques were to be applied, the aim would be to have 100% utilization rate of associated gas - discounting loss of natural gas from powering equipment and unavoidable transportation loss. Finally, the essay will evaluate how current associated gas projects in each region could alter the natural gas economy.

Processing and Flaring Associated Gas

Natural gas is generally transported in pipelines. Pipelines run from the oil wellhead to natural gas processing facilities, and then to commodity trading hubs and distribution centers where refined gas is purchased and dispatched for end uses. Downstream uses for natural gas ultimately require pipelines connected to: utility plants for electricity generation, combined heat-and-power plants for industrial and commercial uses, facilities that use natural gas as raw material to produce plastics, fertilizers and other chemicals, and homes for cooking and heating. Before transportation, all associated gas at oil wells must be processed.

During initial stages of oil production when there is little infrastructure at the well for handling produced hydrocarbons, spurts of associated gas must often be flared for testing and safety. When a well is drilled into oil shale or a conventional reservoir, the gas that is produced is first used for production testing to determine reservoir pressure, flow rates and composition (Ohio EPA, 2012) before flaring. Gas flaring may be mandated whenever there is overpressure in the equipment that handles gas at the well site: automatic valves release gas to prevent explosions and fires. During equipment repairs and maintenance, flaring is also used as an outlet.

² NGLs are heavier hydrocarbon gases are components of natural gas that are liquid at the surface and include propane, butane, pentane, hexane and heptane. Although liquid, they are not substitutes for oil and cannot be transported in oil pipelines like GTL products.

These instances, however, are a small fraction of the total volume that may be flared in the lifetime of the oil well. Most flaring occurs during oil extraction as a continuous stream of associated gas arises from the reservoir.

Guidelines for natural gas processing are dictated by quality standards for safe transportation. In order to insure that natural gas will not condense and clog pipelines, U.S. guidelines specify that natural gas have an energy content within the range $1,035 \pm 50$ Btu per cubic foot³; contain no more than trace amounts of hydrogen sulfide, carbon dioxide, nitrogen, water vapor and oxygen; and be maintained at a specific hydrocarbon dew-point temperature to avoid gas condensation (EIA, 2006). The extent of required processing depends on the make-up of the associated gas. Processing steps can be divided into separation at the wellhead and operations at a central processing plant.

Figure 1 is a schematic diagram for how associated gas is processed and used in different forms. At the wellhead, oil and gas naturally separate through release of pressure or through alternately heating and cooling the wellhead stream in a gas-oil separator (EIA, 2006). Dehydration and removal of contaminants can occur either at the wellhead or at a separate plant. Once hydrogen sulfide and carbon dioxide are processed to acceptable levels, the stream is routed to a separate processing plant⁴. This processing plant strips the stream of nitrogen through cryogenic separation or through an absorbent solvent that adheres to the methane and heavier hydrocarbons while venting the nitrogen (EIA, 2006). After impurities are removed, the different economics of natural gas (methane) and natural gas liquids (ethane, propane, butane and higher order light hydrocarbon chains) comes into play.

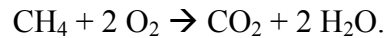
The process of extracting pure methane from the gas stream (de-methanizing) works by cryogenically lowering the temperature of the gas so that methane is still in gas form whereas the higher order hydrocarbon molecules (C_nH_{2n+2} , $n > 1$) condense into natural gas liquids (NGLs). Alternatively, an absorbent liquid hydrocarbon can separate methane from the gas stream. The separated NGLs enter a fractionation process in which the individual hydrocarbons in the stream

³ In the oil and gas industry a mixture of English and SI units are used. The amount of energy of natural gas can be converted from Btu per cubic feet to Joules per cubic meter. If 1 Btu equals 1055.1 J and 1 ft³ equals 0.028316 m³, then 1035 Btu/ft³ multiplied by 1055.1 J and divided by 0.028316 m³ equals 38.5 MJ/m³.

⁴ Carbon dioxide is often re-injected into the oil well for enhanced oil recovery (EOR).

are separated into different holding tanks (EIA, 2006). Holding tanks contain ethane, propane, butane, isobutane, or pentane – each priced higher than natural gas on the market.

After separation and processing at the wellhead, dry gas composed mostly of methane is combusted and flared. Flaring technologies developed in the last 20 years have proven to be 98-99.5% efficient in combusting associated gas to carbon dioxide and water (Stroscher, 1996). The basic combustion reaction is simply



Gas flaring research conducted by the Alberta Research Council and the EPA, which included data from laboratory and commercial sites, pointed to high combustion efficiencies if the liquid hydrocarbon components are completely separated from the stream before it enters the combustion chamber. Liquid carry-over greatly impairs the ability of flaring to completely combust natural gas hydrocarbons. In the Alberta Research Council field studies, flaring of sweet solution gas with liquids was only 62-72% efficient. Liquid droplets of octane, making up 20% of the total hydrocarbon mass flow, reduced flare efficiency from 99% to 93% (Cain, Seebold, and Young, 2002). In addition to liquid content, lower heating value (less than 800 Btu/ft³) produces inefficient combustion and a weaker flame. Flaring efficiency is also reduced when gas exit velocity from the stack is affected by high wind conditions. In order to increase exit velocity, higher btu hydrocarbons can be injected into the gas stream. If the gas has greater than 800 Btu content, the flare will burn efficiently even under high wind conditions (Cain, Seebold, and Young, 2002). Nonetheless, wind guards to protect the flare tip should be added to insure that exit velocity is stabilized against the wind.

Flare systems commonly use a diffusion flame, which is a combustion process in which the fuel and air are not premixed. An optimal ratio of oxygen to fuel is almost never fulfilled in diffusion flames because diffusion mixing is subject to a high degree of uncertainty. Diffusion flames coupled with high wind velocities decrease efficiency. Today, “sonic” flare tips increase the velocity and the pressure of exit stream such that smoke is also reduced (Cain, Seebold, and Young, 2002). Technology to improve flare efficiency has reduced methane leaks in the flare stacks, increased combustion efficiency, and reduced smoke output. Although flaring is preferred to venting methane, carbon dioxide and water vapor products from flaring are still potent greenhouse gases.

Global Warming Implications

Based on the global average of 150 bcm per year, flared natural gas is equivalent to 5% of global natural gas production. Flared gas releases about 400 million metric tons per year of carbon dioxide into the atmosphere (GE, 2011), or about 2% of total anthropogenic emissions in 2011⁵. Carbon dioxide is a powerful greenhouse gas that traps the long-wavelength radiation emitted from the Earth's surface after the surface is warmed by incoming solar radiation. This trapped radiation in turn warms the atmosphere—which is the greenhouse effect that naturally raises Earth's mean global temperature. This warming influence is measured by a quantity called the radiative forcing, which is a measure of how the earth's energy budget is increased by the presence of greenhouse gases in the atmosphere (IPCC, 2013)⁶. Carbon dioxide is the dominant greenhouse gas because of its lifetime in the atmosphere and its large accumulation from anthropogenic emissions. The accumulated carbon dioxide in the atmosphere has a radiative forcing of $+1.88 \text{ W m}^{-2}$ (IPCC, 2013).

Venting releases associated gas from oil production directly into the troposphere without processing or separation. Depending on the wellhead, the vented gas can contain sulfides, natural gas liquids, carbon dioxide, VOCs and methane. Since venting cannot be detected through satellite surveillance, infrared sensors near the earth's surface are required to monitor venting, a procedure that is rarely followed. Methane in the troposphere reacts with hydroxyl to create carbon dioxide, ozone and water in a 10-year period. Hydroxyls, the main sink for methane, are particularly important in the troposphere to break down other pollutants. Methane in the atmosphere has a net radiative forcing of $0.48 \pm 0.05 \text{ W m}^{-2}$ (IPCC, 2013).

The net radiative forcing of methane in the atmosphere is less than carbon dioxide because of its lower overall atmospheric concentration. Kilogram per kilogram, however, methane is a more potent greenhouse gas than carbon dioxide. This is measured by a different quantity called the Global Warming Potential (GWP), which compares over a specific time period the integrated warming effect of a given weight of gas in the atmosphere to that of carbon dioxide. According to the latest estimates of the Intergovernmental Panel on Climate Change

⁵ Based on 2012 anthropogenic emissions of carbon dioxide (31.6 Gt)

⁶ A positive radiative forcing is akin to the Earth's surface receiving more energy from sunlight. As comparison, direct sunlight reaching the Earth's surface at the equator at noon has an irradiance of 1000 Watts per meter squared (Wm^{-2})

⁷ Average radiative forcing from 1750 to 2011

(IPCC, 2013), over a 100 year time period, methane has a GWP of 28—which means (roughly) that a kilogram of methane in the atmosphere has about 30 times the warming effect over 100 years than a kilogram of carbon dioxide. Over 20 years, methane has an even higher GWP of 84 (IPCC, 2013). The decrease in the GWP of methane over time is due to methane’s short 10-year lifetime in the atmosphere (compared to carbon dioxide which remains in the atmosphere for hundreds of years). Over a longer period, methane’s effect on the atmospheric energy budget is caused mainly by its byproducts: carbon dioxide and water.

Efforts to decrease anthropogenic emissions of methane in the troposphere are considered to be highly desirable, which means that flaring is preferable to venting (IPCC, 2013). Although monitor systems for flaring are more developed than venting, figures for emissions usually combine venting and flaring quantities, skewing carbon dioxide emissions data. With today’s standards, it is difficult to separate venting and flaring quantities from reported data.

Besides contributing to global anthropogenic emissions, flaring associated gas damages the regional environment. The site of flaring is a hot spot that impacts the air, water, and biota in the region. Some local impacts include dying vegetation around the perimeter of flare sites, fires caused by horizontal flaring, noise pollution, and sulfur emissions linked to acid rain. The impact of flaring on the local environment varies based on the environment and on the natural gas infrastructure already established. Natural gas infrastructure is a long-term investment for the government that is inextricably linked to the private industry and development. For instance, in Nigeria some flaring of natural gas has transitioned to LNG export and to electricity generation. Nonetheless, Nigeria still has some of the most blatant examples of non-scrubbed flaring near local communities. Russia is a leading producer of natural gas and yet is more focused on developing oil infrastructure than natural gas infrastructure. Russia flares more gas than any other country. In the United States, flaring is addressed by federal regulatory policy on emissions. It is likely that the flaring of associated gas released by hydraulic fracturing, or fracking, in the Bakken and other unconventional plays that produce both oil and gas will be impacted by the EPA’s 2014 standards for emissions. While lack of infrastructure exacerbates flaring, an environment’s resilience to air, noise, and temperature pollution also determines local environmental impact.

Economics Fueling Flaring

Natural gas costs more to transport and store than oil, and has limited destination flexibility – LNG for export and pipelines for transport to national markets. Less attention on developing natural gas than oil transportation and infrastructure creates insufficient investment to meet upstream and downstream challenges. The period after exploration and before production is usually a grace period in which flaring continues unchallenged by regulation. The main economic incentive to flare gas is bypassing the need to transport gas from the production site to a natural gas hub. In addition to physical impediments in building infrastructure to transport gas in upstream sector, there is also uncertainty in natural gas prices downstream. Traditional long-term contracts linking natural gas to oil prices are becoming outdated. Increased competition and supply of natural gas has reduced natural gas spot prices in Europe to an average of 30% less than prices in long-term contracts (Stern and Rogers, 2013). Although spot-market pricing allows nations to have more autonomy with purchasing and utilizing natural gas, long-term contracts are beneficial for capital intensive and debt-financed natural gas infrastructure projects. Long-term contracts allocate risk among the producer, purchaser, and financial backers. Raw natural gas prices were approximately twice as volatile as raw oil prices (Ramburg and Parsons, 2012)⁸. Due to fluctuating price parity between natural gas and oil, there is a higher risk in infrastructure investment to implement natural gas technologies.

Intermediate between low (and volatile) natural gas prices and high oil prices are prices for natural gas liquids (NGLs). Natural gas liquids contain a higher hydrocarbon content than natural gas, and their end uses include inputs for petrochemical plants, residential and commercial heating and cooking (for example, propane), and blending into vehicle fuels (EIA, 2012). NGL contracts are more closely linked to oil prices than natural gas. Since NGLs are byproducts of oil extraction, processors that separate dry gas to be flared from NGLs create contracts with producers for long-term delivery of natural gas. In most cases these contracts allow the processors to keep the NGLs as payment, while the producers receive pipeline-quality methane. In today's market, with methane and NGL prices fluctuating, hybrid contracts are created to mitigate risk for the processors. NGLs must also be transported through natural gas pipelines from the production site, so investment in NGLs covers some natural gas infrastructure

⁸ Model covered natural gas prices and oil prices between 1997-2010.

demands. Not all associated gas at oil wells produce a saleable quantity of NGLs, and there for natural gas pricing must also be sufficient for its own infrastructure investment.

The case studies on flaring in Russia, Nigeria and the United States, presented in the next section, highlight some economically feasible alternatives to flaring associated gas. These include: enhanced oil recovery (EOR), electricity generation, processing for natural gas liquid (NGL) products, liquefied natural gas (LNG), and traditional pipeline transfer. **Figure 2** bases the economics of each technique on the amount of associated gas generated versus distance to market. These options, which are not exhaustive, could be applied to every region; however, the regional geology, along with local political and social conditions, ultimately determine which, if any, gas utilization project will most likely be invested in. Some projects are already established, such as the NLNG terminal in Nigeria; others are currently under construction such as the gas processing facility in Russia's Yamal Peninsula, or are in initial stages of planning, such as the gas pipelines for the Bakken Shale. Planning private-public partnerships to utilize associated gas must also factor in national regulations on flaring.

Western Siberia and Yamal Peninsula, Russia

Russia flares the largest volume of associated gas per year, an estimated total of 38 bcm in 2009, accounting for 25% of global gas flaring⁹. This annual volume contains an estimated 22 bcm of dry gas and 24 million tons of LPG (Associated Gas, 2009). These estimated flare volumes are not based on accumulation of field report data, but rather on information gathered from satellite observations and information released by Gazprom, Russia's state-owned oil and natural gas corporation. As the owner and operator of all the natural gas transmission systems, Gazprom strengthens its monopoly by limiting natural gas input from independent operators. Although Russian policy has addressed unequal access to natural gas pipelines, Gazprom sidesteps regulations by deeming the gas as not "appropriate quality." Gazprom must, however, relax its exclusivity as oilfields and gas fields in Western Siberia start to see dwindling production capacity. This production decline in the giant gas fields in Western Siberia has

⁹ Global average of 150 bcm, (GE 2011)

increased pressure on Gazprom not only to recover associated gas but also to produce from new fields in the Yamal Peninsula.

Petroleum Geology

The Nadym Pur Taz (NPT) region in Western Siberia is the world's largest natural gas production center, accounting for over 90% of Russia's gas production (Gaiduk and Shlyapnikov, 2006). The giant gas fields there have been in continuous production since the mid-1950s; total production in 2010 was 654 bcm (Soderbergh, 2010). According to Gazprom officials, production of gas has declined by 20-25 bcm per year since 1999 (IEA, 2009). **Figure 4** illustrates West Siberia's daily decline in oil production since 2005, which roughly parallels that of gas. Unforeseen relatively rapid decline of the NPT region is due in part to the regional petroleum geology. Giant gas fields in NPT consist of Cenomanian age (94-99 Ma) reservoirs. During the Cretaceous period, terrestrial plant organic matter was deposited in this region and decomposed by bacterial action. Buried at a depth of 3-4 km, organic matter (kerogen) hosted by porous sandstone was not exposed to high enough pressures to generate oil. Since the sandstone reservoirs are highly permeable, the Urengoy giant gas field and other giant gas fields in the NPT are all connected hydraulically. The solid matrix of the 100 to 200-m thick sandstones is not cemented tightly, which means that both gas and water can flow through the reservoirs with ease (Lyle, 2006).

Because of a policy to rapidly produce from the reservoir zones, as well as delays in installing compressor stations, water levels started rising quickly as a by-product of gas extraction, and have started to encroach on the producing gas traps (Lyle, 2006). By 2002, the Cenomanian reserves in Urengoy declined in production by 65.4%, much faster than expected (Gazprom, 2005; PRF, 2003; Stern, 2005). Even with the opening of new gas fields in the region, production decline of the three giant gas fields, Yamburg, Zapolyarnoe, and Urengoy, might threaten the company's ability to meet its pipeline capacity and export demands of 168 bcm per year to Europe¹⁰. Gazprom's planned level of gas output of 524 bcm by 2012 was expected to be provided by operating fields and by new fields starting production in the NPT-region. However in 2012, Gazprom produced only 515 bcm and purchased the rest for resale from independent natural gas producers.

¹⁰ 168 bcm is demand in 2013, but it may be higher since Gazprom signed contracts to bring a total of 2500 bcm over the next 15 years.

To combat already declining production capacity in Western Siberia, Gazprom has sought gas extraction and production in the Yamal Peninsula. The Yamal Peninsula is divided into the North, Central, and Southern group based on reserve size. Gazprom will first invest in the Bovanenkovo production zone (Central Group), projected to reach up to 220 bcm/year. Subsequently, the Tambey production zone (Northern Group) is projected to produce up to 65 bcm/year (Gazprom, 2009). Finally, the Southern production zone will produce 30 bcm/year (Gazprom, 2009). Refer to **Figure 3** for a map of oil and oil condensate fields in the Yamal Peninsula, located North West of the NPT region.

Petroleum and natural gas in the Yamal Peninsula are sourced by Jurassic period Tyumen and Bazhanov formations. The Tyumen formation accumulated organic material under alluvial-lacustrine and shallow marine conditions and contains oil-prone type II kerogen (Chakmakhchev et al., 1994). The upper Jurassic Bazhanov formation was deposited under deep marine conditions by rapid subsidence of the basin (Chakmakhchev et al., 1994). However, hydrocarbon indices reveal that advanced thermal maturity altered the kerogen and prevented oil generation. The Cretaceous interval reveals a dry gas segment based on low hydrogen and oxygen index values (less than 2.5 mg HC/g); only 25% of samples had an above-average hydrocarbon yield (Katz et al., 2003). Based on a regular thermal maturation profile, the Cretaceous section is thermally immature and at best can generate natural gas.

Production capacity using Gazprom's higher estimation is 360 bcm per year and will bolster gas export from Western Siberia to Europe (Soderbergh et al., 2010). Gazprom is currently building a pipeline to transport gas from the Bovanenkovo to connect with the existing Nord Stream Pipeline. The Nord Stream exports gas to European markets by connecting to Germany. The French company Total, a leading natural gas producer, is investing in a 16.5 MT/year LNG terminal for the southern production zone (Soderbergh et al., 2010). The pipeline and LNG routes have their own risks in terms of withstanding extreme arctic temperatures and weather in the Yamal Peninsula.

Flaring in Spite of Increased Transportation Demands

The western route from Western Siberia includes three pipelines: the Nord Stream, the Central Corridor, and the Southern Corridor. The Nord Stream is the newest pipeline connecting Russia and Germany, transporting 55 bcm (Soderbergh et al., 2010). The Nord Stream will tie in gas produced in Yamal as well as the gas produced in NPT. Despite new gas production from the

Yamal peninsula, PFC Energy suggests that pipelines will still have unused capacity of 20-40 bcm/year by 2020 (PFC, 2007). According to Russian officials the NPT-region's production could account for only 26-30% of total output by 2030 (IEA, 2009). There must also be an increase in gas processing plants, either in the NPT Region or elsewhere, to separate natural gas liquids from the dry gas. Since the NPT region is a hub for both extraction and processing gas, it is economical for new gas sources to be directed to the region. If priority for the existing pipelines is given to gas from Yamal and other new gas fields, then there will be a conflict of interest in terms of recovering associated gas from existing fields. To address this conflict of interest, Russia has their own policies to increase utilization of associated gas and to monetize it such that it is comparable to public prices for natural gas. However, as with current policies for associated gas there is high uncertainty as to whether the regulations will be followed.

Flaring is currently unregulated by the Russian government, even with announced plans to utilize 95% of associated gas by 2011 - a goal currently unmet (Soderbergh, 2010). The NPT regional administration has established its own 5% limit on gas flaring, but allows operators to exceed the limit if they can demonstrate that utilization is uneconomical. According to reports from the regional administration, only 26% of its 213 licenses were in full compliance (PFC Energy, 2007). PFC Energy suggests that in the short to medium term, as new gas fields are in development in Yamal and NPT, Gazprom should utilize associated gas to meet natural gas pipeline demands. Cost for associated gas recovery includes delivery to a gas processing plants, quality and volume.

Most flaring is concentrated around gas processing plants in Western Siberia, which indicates that flaring is the preferred choice for independent operators and Gazprom when processing plants are at their limits. In 2008, PFC Energy reported that all gas-processing plants in Western Siberia are operating at maximum capacity especially in the winter months. Flaring takes place within 160 km of an existing gas processing plants plant, especially in the region south of gas-processing plants (PFC Energy, 2007). **Figure 5** maps out the flaring site in relation to natural gas pipelines in Western Siberia. The regional market south of the gas-processing plants in the Southern Corridor is small- the region has a scattering of oil towns with an average population of 100,000. This suggests that there is backflow in the south because of low demand, insufficient processing and transportation capacity. If associated gas produced in the south could be redirected to the north, it could also be exported to Europe via the Nord Stream.

Utilizing Associated Gas: Pipelines and Enhanced Oil Recovery

Regulatory bodies in Russia often lack the human and financial resources for carrying out flaring monitoring and regulations (IEA, 2006). Despite lack of regulatory pressure, oil companies have agreed that a consolidated effort to use associated gas will be more economical for all stakeholders. Lukoil proposes to use gas for electricity generation and to process NGLs for market sales (IEA, 2006). There must also be structural changes for the independent operators to obtain access to gas processing facilities and gas pipelines. Although just 30% of Gazprom's gas production is exported to European markets, in 2008 these exports accounted for 60% of total revenues (Pugliaresi et al., 2009). For connecting to Gazprom pipelines, an operator at a new gas field must invest in a gas treatment plant, two compressor stations to bring the gas to 75 atm, and pipeline for the distance from the field to the main pipeline (IEA, 2006). If the associated gas is sold at Russian domestic market prices with no carbon pricing, it will be much lower than the marginal cost of production for Gazprom. As a monopoly, Gazprom has no reason to pay more than its marginal cost of production, which is estimated to be \$22/ 1000 m³ (IEA, 2006). However, decline in production in existing fields, Russia's involvement in the Global Gas Flare Reduction initiative, and burden of investing in new fields may incentivize Gazprom to pay a higher price for associated gas.

Depending on the scale of the gas field or the amount of associated gas produced, other economical options to use associated gas can be electrical generation through CCGT, processing for LPG, piping for sale, or enhanced oil recovery through gas injection. Calculations by PFC Energy take into considerations a 10% netback on investment to calculate which gas utilization projects are most effective¹¹:

- For small fields flaring 0.1 Bcm/y or less, distributed (local) power generation is the most economic option;
- For medium-sized fields flaring 0.1 – 0.5 Bcm/y, the most economic option is a gas processing plants, provided inlet gas prices are increased to at least \$35/Mcm.

¹¹ A netback price represents the maximum price an investor building a new facility (GPP, power plant, GTL plant, EOR system) plus the infrastructure needed to bring the associated gas to the facility would be prepared to pay a producer to purchase associated gas at the wellhead, while earning a 10% real return on his investment (PFC, 2007)

- The most economic option for large fields flaring more than 0.5 Bcm/y is power generation using a CCGT and sale of electric power to the grid. (PFC Energy, 2007)

Enhanced oil recovery for fields with diminishing oil production is another viable option if the geology is suitable for gas injection. Under tertiary recovery methods, enhanced oil recovery methods are split between gas drive and thermal methods. Calculations from EIA indicate that enhanced oil recovery based output will amount to 3 million tons of oil in 2015, and about 20 million tons in 2030 (E&G, 2013). Of these options, increased competition from new entrants in the local natural gas market will produce a more cost-efficient industry that is not reliant on Gazprom's regulated prices. If Russia's domestic market for natural gas is more competitive, and the new entrants enter Russia's international trade portfolio, then Gazprom will have pressure to utilize associated gas as new gas fields from independent operators open.

Environmental Impact to Yamal Peninsula

Oil and gas in the Yamal Peninsula has been scouted since the 1960s; however, extraction was not possible or necessary until recently because of the region's harsh arctic conditions and plentiful supply in Western Siberia. The Yamal Peninsula is home to the Nenets indigenous group, whose livelihood depends on herding reindeer and raising them on arctic pastures. Through natural gas development and extraction, infrastructure has upset the highly sensitive arctic ecosystem. The three most widespread types of environmental disturbances are off-road vehicle traffic, exploratory drilling, and sand excavation (Vilchek & Bykova 1992; Khitun 1997). Plant cover is already completely destroyed over 450 km² within gas and oil fields and 1800 km² along the main pipelines (Forbes, 1999). Transportation will continue to expand from the south northwards as Gazprom and Total expand their natural gas extraction operations. The Nenets have adapted to their new neighbors, commenting that "the oil companies always take the best land." Although natural gas development in the Yamal peninsula may have been inevitable, using associated gas in Western Siberia could have delayed development.

Niger Delta Basin, Nigeria

Although the distribution of oil and gas in the Niger Delta is complex, the delta has been producing oil since the early 1970s and has dominated the country's economy since. Oils in the Niger delta are of the light waxy type, and most known gas accumulations are found in

association with oils are of thermal origin (Doust, 1989). A typical petroleum well on the crest of an anticline has associated gas accumulated at the cap of the well. About 52% of Nigeria's total proven gas reserve is associated, while the remaining is non-associated in conventional reservoirs (ICF, 2006). During production, the top of the oil column in the reservoir rocks drops and creates more space for the associated gas. The zone of associated gas increases as more oil is drawn from the well, and eventually becomes a significant component of the production stream.

There are about 123 flaring sites in the Niger delta, and for some oil wells 99% of associated gas is flared. The amount of gas flared is usually correlated to the amount of oil produced. However, flaring in Nigeria is so prevalent that the country is only the 7th largest oil producer (at 2.10 million bbl/day), but flares the second largest amount of natural gas. Nigeria flared 14.58 bcm of natural gas in 2011, about 10% of the global total (EIA, 2013). Although flaring was reduced from 16.28 bcm in 2007, the reduction is attributed less to incentives on funding projects to capture associated gas and more on a reduction of oil production (EIA, 2013). Crude oil production reached its peak of 2.44 million bbl/day in 2005 but has declined by almost 14% due to militant violence disrupting the production chain.

Petroleum Geology

The Niger Delta was established during the Cretaceous when fracture zone ridges appeared in what is now the West Coast of Africa and rifted the African shield (Doust, 1989). A triple junction rift in the region of the Niger Delta was an optimal basin for sediment buildup. During the Cretaceous and Tertiary episodes of expansion and contraction in the delta caused a constant flux of sediment, carbonates, marine and lacustrine organic material into the basin.

The petroleum system of the Niger Delta can be subdivided into macro structures, or depobelts (Doust, 1989). A depobelt contains one or more paleontologically distinct shale horizons that succeed one another as the delta advanced and dipped southward during the Tertiary period. A depobelt, therefore, forms the structurally and depositionally most active portion of the delta at each stage of its development (Doust, 1989). As the facies in depobelts accumulate more sediment, they start to slope southwards. Increased sedimentation and pressure creates a series of normal faults upslope and a compressional toe downslope. **Figure 6** illustrates how depobelts form in every cycle of sedimentation in the Niger Delta. Each depobelt is a separate unit with its own structural traps for petroleum.

There are three types of petroleum systems present in the Niger Delta: Lower Cretaceous (lacustrine), Upper Cretaceous–Lower Paleocene (marine), and Tertiary (deltaic) (Haack et al., 2000). The predominant deltaic petroleum system contains terigenous land plants in its source rock. Depending on where one is on the delta, a reservoir may be more gas prone or more oil prone. Differences in the hydrocarbon oil to gas ratio is due to not only heterogeneity of source rock type but also the punctuated period of burial (Evamy, BD, et al., 1978). Geochemically, the oils originate from the same family of light and waxy type kerogens (type II, II-III, and III) (Doust, 1989). Measurements showing C₂₉ steranes¹² comprising over 50% of the crude oil indicate a high contribution of organic material from land plants near the paleodrainage basin (Haack et al., 2000). Compositions with C₂₉ steranes less than 40% suggest that the organic material is more likely deposited in marine conditions. **Figure 7** maps out distribution of terrestrial versus marine organic matter, and where oil and gas is concentrated. In the offshore part of the basin, more oxygenated environments during deposition creates gas-prone areas. Oil-prone fields are concentrated in the northwest and southeast delta where terigenous organic material was buried in more anoxic conditions. Highest maturity of organic material is observed in the center of the Niger Delta, where geothermal gradients are higher.

By observing migration of hydrocarbons through normal faults, scientists have proposed multiple theories for the depth and origin of the source rock. Source rocks are difficult to locate in delta wells because of thin beds, in which sediment deposition is episodic and basin lithologies are eroded (Evamy, BD, et al., 1978). One theory posits that deep major faults are conduits for mature hydrocarbon, or oil, migration (Haack et al., 2000). Based on **Figure 6**, the northern regions located up dip of the major structures are most likely to contain oil. Younger depobelts located to the south and dipping southwards are more likely to trap gas because the source rocks are in a shallower region. Through observation, the gas-to-oil distribution increases down plunge and in a seaward direction (Evamy, BD, et al., 1978). Hydrocarbons are characteristically trapped in anticlines of each depobelt, which are created by growth faults and sediment deposition. The sediments first accumulate before hydrocarbons migrate vertically from source rocks. Parallel and subparallel normal faults between depobelts break up the hanging wall strata in the center of the Niger Delta. These structural traps, capped by interbedded shale in the

¹² C₂₉ steranes are biomarkers that reflect the abundance of terrestrial organic matter in the parent crude oil feedstock's source rock (Mondowan et al., 1985)

Agbada Formation, create a series of oil reservoirs (Doust, 1989). Proponents of deep-marine shale migration believe that the source rock is located at a depth of ~ 2900 m and 3375 m offshore and on-shore of the Niger Delta respectively (Ekweozor, Chukwuemeka M., and Ndibe V. Okoye, 1980). Others believe that the sources rocks are located in a shallow depth along the coast and hydrocarbons migrated within the formation horizontally. Based on the prevalence of traps created by normal faulting, hydrocarbons most likely accumulated by migrating vertically.

Utilizing Associated Gas: Liquefied Natural Gas and Gas to Liquid

Violence from militant groups in Nigeria have forced oil companies to abandon projects the Niger Delta and declare a force majeure, in which the company cannot satisfy contractual agreements for oil because of circumstances beyond their control. Chronic issues along upstream oil production include: ageing pipeline infrastructure, pipeline leaks and illegal off-takes, and refineries operating under capacity. Along with violence as an impediment to oil production, unstable political and financial regimes also exacerbate flaring. A combination of factors—the deteriorating security situation, a history of low (5%) usage of natural gas, lax pressure to develop domestic natural gas infrastructures, and lack of partner funding due to uncertainties surrounding the Petroleum Industry Bill (PIB) targeted at reform—have stunted development of projects to mitigate flaring (Ukpohor). The PIB proposed in 2008 changes the organizational and fiscal structure governing all natural gas and oil joint partnerships. The PIB also includes the Gas Master Plan in 2008 aimed at increasing use of associated natural gas and creating a domestic natural gas network for consumption. Reforms until 2012 have delayed passing the PIB, which creates uncertainty and has delayed current development of natural gas projects. Despite local objections to flaring and governmental “deadlines” to end flaring in 2010, oil companies in 2008 such as Chevron Nigeria Limited flared 64.3% of its associated natural gas, Total Nigeria flared 99%, and Pan Ocean, 98% (Madueme, 2010).

A mature natural gas distribution network is unlikely to be built in the Niger Delta because of security risks and the state controlled price of natural gas prevents investment. The largest projects currently in development are: Nigerian Liquefied Natural Gas (NLNG), West African Gas Pipeline (WAGP), West Niger Delta Liquefied Natural Gas (LNG), Brass River LNG Plant, and the Escravos GTL plant by Chevron. LNG projects are developed exclusively for export whereas WAGP is expected to transport 0.92 bcm/day of natural gas domestically and to Togo, Benin, and Ghana for power generation. In 2012, WAGP was shut down for pipeline

repairs and as a result natural gas exports dropped to 0.40 bcm/day. With militant groups actively sabotaging oil and natural gas infrastructure, companies prefer to invest in export on a singular LNG facility instead of transporting natural gas through a network of pipelines. In 2012, the only operating LNG plant, NLNG on Bonny Island exported a total of 26.9 bcm. Although LNG serves to increase use of associated gas, it does not address domestic demand for the electricity and energy that natural gas provides. The domestic gas market and electricity generation is currently at an immature state, with 50% of Nigeria's population without access to electricity (World Bank, 2010). As a replacement to burning biomass for fuel, natural gas is a cleaner source for electricity and heat. Nigeria plans to increase electricity generation from fossil fuel sources to more than 20,000 MW by 2020 – compared to 6,000 MW in 2012 (IEA).

Currently, the only operating LNG terminal is the NLNG terminal on Bonny Island. LNG technology transforms gaseous methane into a liquid through pressure and temperature manipulation. There are six liquefaction trains at Bonny Island, each train is an independent unit for gas liquefaction. Currently gas supplies for the LNG facility, which has a project lifespan of 22.5 years, is sourced from several oil and gas fields, including some associated gas. With planned expansion to train 7 and 8, the projected capacity of NLNG will increase from 30 Mt/year to 38 Mt/year.

In order to use existing oil pipelines instead of building natural gas pipelines, a GTL plant was built in the Niger Delta. The Escravos GTL plant has a capacity of 33,000 barrels per day (bpd) of liquid production, and the project is designed to process 9200 m³ per day of natural gas from the Escravos Gas Plant (EGP) expansion (Atuanya, 2014). After the Escravos Gas Plant separates sulfur and liquids from methane and sends the “sweet gas” to the GTL plant. Sasol's technology for the Escravos GTL plant is to use an autothermal gas reformer to produce syngas, which is the most capital intensive of a GTL complex.

In autothermal reforming, methane is mixed with steam and oxygen in a reactor to create a high-pressure syngas of carbon monoxide and hydrogen with carbon dioxide as a byproduct. This is a standard step in a chemical process called the Fischer-Tropsch reaction. For the Escravos GTL plant, the Fischer-Tropsch reactor uses a cobalt catalyst (iron and nickel are substitutes) in a slurry to recombine carbon monoxide gases into long chain hydrocarbon molecules, which is known as synthetic crude. Minimizing the size of the facility to carry out this exothermic process has been a challenge ever since the FT process was introduced in the mid-

1920s. In the product-refining phase, the newly created long-chain hydrocarbon molecules undergo cracking to create lighter hydrocarbons. Chevron, the majority owner of the plant, will provide its isocracking product upgrading technology to produce the desired GTL products. Operations are expected to start up by mid-2014, producing diesel, kerosene, naphtha and LPG through the Fischer-Tropsch process. Steam produced as a by-product in the GTL plant will be used to generate electricity for operations.

Investing in LNG terminals is less of an infrastructure risk than investing in pipelines or GTL technology. Nigeria has vast natural gas reserves in comparison to the amount by which demand for gas is increasing. So there is little incentive to conserve associated gas. Pressure to utilize associated gas have stemmed from grassroots environmental efforts, international attention from the UN, and the government. Unfortunately, there is a lack of transparency because joint partnerships with the Nigerian Petroleum Company create a legal veil over information. Militant groups have interrupted oil and natural gas extraction, and will persist as a problem for production as long as the social and economic conditions of Nigeria do not improve. Illegal off-takes and damaged pipelines have stagnated oil production. Continued investment in this oil-producing region, which is also the 4th largest LNG exporter is constantly upset by militant disruptions and ongoing political and regulatory uncertainty.

Environmental Impact to Niger Delta

Flaring in Nigeria is not just an eyesore to the local population; it is also a major hazard to the environment and to human health. In the Niger Delta, there are four ecological zones: coastal barrier islands, mangroves, freshwater swamp forests, and lowland rainforests (Ambio 1995). Flare emissions to some regions over others are amplified by differences in flaring technologies compounded with atmospheric wind circulation. In a 100-meter radius to a flare site, vegetation such as cassava and pepper crops have lower yields and reduced size (Emoyan, 2008). Retarded growth may be caused by increased soil temperature. Although the natural gas in Nigeria is sweet and doesn't contain much sulfur, incomplete combustion without scrubbing can release hydrogen sulfide into the atmosphere. Hydrogen sulfide when oxidized and reacted with water will produce acid rain. Inconsistent adherence to Nigeria's anti flaring laws lead to different companies following their own practices for flaring. In addition to the environmental impact of flaring, visible and audible non-stop flaring of natural gas has impacted the local

population's social morale. The "sun that never sets" is a beacon of the dominance of the petroleum industry in Nigeria.

Bakken Oil Shale, North Dakota

The Bakken Shale is an example where insufficient infrastructure has led to stranded gas that must be flared according to the latest EPA standards. The associated gas in the Bakken has a high NGL content that in principle makes gathering and processing of associated gas economic. In February 2014, the price of natural gas delivered to the main hub is \$4.50/MCF resulting in an oil-to-gas price ratio of 18:1 (NDIC, 2014). Compared to a ratio of 31:1 one year ago, it is currently more economical to expand gathering lines and build gas processing facilities. With 1,129 active wells and 130 wells waiting on completion, the North Dakota Industrial Commission (NDIC) projects that there will be around 2,240 additional future wells, all of which will require natural gas pipeline connections (NDIC, 2014). Flaring has hovered around 30% however expansion of the Tioga gas plant from 110 MMCF to 250 MMCF is expected to reduce flaring¹³ (EIA, 2013).

Petroleum Geology and Hydraulic Fracturing

In the Williston Basin of North America, the lower and upper Bakken Shales are petroleum system source rocks. The Williston Basin is an elliptically shaped cratonic basin located in North Dakota, in which layers of black mudstones were deposited during the Late Devonian and Early Mississippian, from 350 Ma to 400 Ma (Gerhard et al., 1990). During this time period a large, shallow epicontinental sea with estuarine-like circulation covered the Bakken Shale (Smith and Bustin, 1998). Since the sea was semi-enclosed, an equatorial undercurrent entered the basin providing nutrients to enrich biological productivity in the surface photic zone (Smith and Bustin, 1998). Intense marine organic production forced an anoxic zone at the bottom waters, creating the organic matter for the upper and lower Bakken Shales. The upper, middle, and lower Bakken Shales differ in organic content because relative rise and fall of sea level causes different rates of sedimentation and burial of organic matter. The upper and lower shales contain on average total organic content (TOC) between 8 - 10%, in the middle range for prolific petroleum source rock (Smith and Bustin, 1998). In comparison, the middle Bakken Shales, formed in a period of shallow water and contain a mix of mudstone and

¹³ Temporary shutdown of the Tioga plant has increased flaring high of 36%

sandstone, have on average TOC of less than 1% (Smith and Bustin, 1998). The Upper and Lower Bakken Shales are the zones that are hydraulically fractured for oil production.

The Bakken is considered to be a major petroleum basin. Its source rock captured the kerogen and petroleum because of the Nesson double folded anticline. Faults generated through the development of the Nesson anticline create linear pathways for hydrocarbon migration from shale reservoirs (Gerhard et al., 1990). These existing fractures are important in the overall process that generates petroleum production after hydraulic fracturing. Hydraulic fracturing uses fracking fluids to create new fractures, or enlarge existing fractures, in otherwise impermeable shale formations. When the new fracture space is propped open with sand or other proppants mixed in the fracturing fluid, pathways are created for oil and associated gas to escape from the rock into the wellbore. Geochemists have analyzed the organic content of the Bakken Shale, and identified the kerogen type is primarily type I/II. The USGS reported that the Bakken Petroleum Systems contains 7,375 MM barrels of oil, 6,723 billion cubic feet of gas, and 282 MM barrels of natural gas liquids (USGS, 2013). With data pointing to a rich source rock, and indicated overpressure at the Three Forks fold, which rests underneath the Lower Bakken Shale, hydraulic fracturing is the best-fit technology for extracting the petroleum.

Utilizing Associated Gas: Pipeline and Natural Gas Liquids

According to North Dakota Industrial Commission (NDIC), producers are allowed a maximum one-year flaring period after the well is drilled without paying taxes or royalties on the quantity flared. After one year (or an extensional period due to economic hardships), the producers must pay taxes and royalties for the natural gas is sold on the market. At any well site with uncontrolled emissions, flaring must be applied with 98% destruction efficiency (DRE) if methane emissions are greater than 20 throughput yield (tpy¹⁴) and with 90% efficiency if methane emissions are less than 20 tpy (Environ, 2013). In the Williston Basin, subpart OOOO of the EPA's new emission standards¹⁵, is expected to apply flaring controls on crude oil tanks (Environ, 2013).

Rich associated gas contains natural gas liquids (NGLs) and if sold increases the overall wellhead netbacks, which rely solely on the oil market price on the Clearbrook Index¹⁶. Payback

¹⁴ Throughput yield (tpy) is defined as the number of units coming out of a process divided by the number of units going into the process in a certain period of time.

¹⁵ Effective after August, 2013

¹⁶ Clearbrook Index=WTI Price – CLB Diff – T&G

for a drilled wellhead without sale of associated gas is estimated to be as short as two to three months to one and a half years, which is a relatively short payback period compared to traditional oil wells. The cost of drilling a well in the Bakken averages around \$8-10 million, while the tie-in cost of adding a gathering line is around \$0.5 M (Lutz, 2013). While NGLs, priced at \$1.00/gallon will not completely eliminate flaring, it will create a viable secondary revenue stream and reduce the volume of natural gas flared (Wocken et al., 2013). In the Bakken a 10-12 gallon of NGLs/Mcf of associated gas is a high liquids ratio (Wocken et al., 2013). Separating NGLs from dry gas requires processing at the well site, cooling at -29 °C and storing NGLs in tanks with pressure of 200 psi (EIA, 2014). Gathering lines are the current system bottlenecks in the Bakken Shale. Given their limited access to NGL pipelines, North Dakota gas processors have tended to fractionate and produce NGL components, instead of shipping mixed NGLs (Wocken et al., 2013).

An alternative to waiting for natural gas pipeline infrastructure is distributed power generation. Without much additional processing from standard wellhead gas separation, the lean gas can fuel a combined cycle gas turbine (CCGT) to generate electricity and provide grid support as well as power for hydraulic fracturing operations. While feeding electricity to the grid is a straightforward design, understanding the local electricity demand from variable number of rigs increases project complexity. In **Figure 9** existing power lines are indicated next to flaring sites to identify areas for potential new lines to feed the grid. As an example, BEPC¹⁷ is forecasting the load increase from 600 MW in 2010 to over 1900 MW by 2025 in the oil-producing area of western North Dakota and eastern Montana (Wocken et al., 2013). In order to ensure this load demand, electricity generation in the Williston Basin which will range from 0.5 - 10 MW must also grow. Power requirements in the Williston will be long term since it must match the Bakken oil well's 25-30 year life span. Power load demand at the wells is driven by: electric motors driving pumps, compressor stations, and gas processing plants (Wocken et al., 2013).

Environmental Impact to North Dakota

Hydraulic fracturing in the Bakken Shale has its own set of environmental implications. Major issues with hydraulic fracturing are fracking fluid disposal, aquifer contamination, land footprint, and air quality (EIA, 2014). In addition to water use, air pollution from methane leaks

¹⁷ BEPC: Basin Electric Power Cooperative; a major municipality that provides power to North Dakota.

and flaring is currently under heightened scrutiny. A recent study on US methane emissions from gas and shale gas wells found that current EPA emissions inventories under predict methane values observed in the atmosphere (Brandt, 2014). But hydraulic fracturing is also unlikely to be the dominant contributor to total methane emissions, especially if most wells flare instead of vent associated gas (Brandt, 2014). Another consideration in evaluating the environmental impact of hydraulic fracturing is leakage of methane from new pipelines meeting new wells in the Williston Basin. Methane leaks add to total methane emissions from hydraulic fracturing even if it is not at the extraction site. Secondary methane leaks from transportation or from gas processing facilities, although not insignificant, will not be addressed in this paper.

Conclusions

Natural gas is becoming a more versatile fossil fuel as new technologies diversify its applications from mostly electricity generation to transportation fuels and chemicals. It is the fastest growing fossil fuel in world energy and may soon become the world's largest single source of primary energy as it replaces coal in electricity generation and oil in heating and transportation. The US Energy Information Administration estimates that natural gas will pass petroleum as the primary fuel source in the United States within one to two decades (EIA, 2010). In the United States, the use of horizontal drilling and hydraulic fracturing has sparked a "natural gas revolution" by extracting gas from source rock (shales) and tight conventional (sandstone) reservoirs. These unconventional resources promise a relative abundance of natural gas in the United States in coming decades. As this technology travels around the world, the overall supply of natural gas will continue to grow especially in developing and industrializing nations. If the large difference between natural gas prices in Asia, Europe, and the United States continues to widen, there will be strong economic incentives to consolidate global gas hubs and reduce volatility in natural gas pricing.

Associated gas from oil wells can supplement growing demand for natural gas and reduce the rate of extracting from new natural gas fields. Utilizing natural gas is cleaner than burning all other fossil fuels, especially coal and biomass. Natural gas emits half the carbon dioxide, one fifth the nitrogen oxide and one percent as much sulfur oxides as coal when fired at a power plant (EPA, 2013). Nitrogen and sulfur oxides are leading causes of atmospheric pollution in the form of smog and acid rain. In developing countries, such as Nigeria, energy needs are addressed

through inefficient biomass burning. Biomass emits sulfur oxides, nitrogen, and volatile organic compounds (VOCs) in the atmosphere, which exacerbate air quality and are especially noxious to human health. For direct emissions, then, substitution of natural gas for coal and biomass is generally viewed as an environmental good.

But despite these positive developments, the environmental footprint of natural gas may be growing because of flaring and venting. The price of natural gas is still too low compared to oil to provide enough incentive for investment to reduce flaring of associated gas produced during oil extraction. In February 2014, the oil-to-gas price ratio from the Bakken Shale was 18:1 (NDIC, 2014). Without monetizing carbon emissions or severe fines for flaring, capturing natural gas and transporting it to market is difficult to be economical. In the US, natural gas pipeline construction or expansion on average takes three years from announcement to service (EIA, 2014). Investment in these pipelines hinges on several factors: the value of natural gas, the presence of a distribution hub with enough storage to handle the pipeline capacity, and uninterrupted natural gas flows. Given these parameters, there must be a long-term plan for natural gas investments to receive payback from investments. The value of associated natural gas has increased as international policies and national policies have incentivized use of associated gas.

Measures from the Global Gas Flaring Reduction Program include: a clean development mechanism (CDM) to structure private-public investment, pricing carbon emissions, and increased gas flare monitoring (World Bank, 2005). Although this program is voluntary, Russia and Nigeria have opted into the program to address their flaring concerns. The most effective flare reduction countries use a combination of close monitoring, penalties, incentives and targeted infrastructure investments to drive up the opportunity cost of flaring associated gas (GE, 2011). Investment in natural gas infrastructure is crucial for developing countries, even if investing is a higher risk. Along with exporting natural gas to support the economy, local natural gas transport to power facilities benefits development. Governments should also take on additional guarantees to support new public-private partnerships and joint ventures. Regulation is key to enforcing anti-flaring projects and legislation. Even though Russia joined the GGFR in 2009, its government has had lackluster performance in enforcing its 5% flaring rate – a goal that was set for 2011. Political instability in Nigeria increases uncertainty towards long-term infrastructure investments, which is partly indicated by the 6-year postponement of the

Petroleum Industry Bill. Although Nigeria's Gas Master Plan supports use of associated gas and encourages investment in a national natural gas network, it is not equipped to form public-private partnerships to address these goals. With increased transparency in monitoring natural gas flaring and a robust framework for investing in gas projects, associated gas can be consumed for energy.

A range of proven technologies can mitigate natural gas flaring. These technologies can be divided into natural gas infrastructure independent and dependent types. Natural gas dependent technologies include NGL processing plants, natural gas pipelines, and power generation for the grid. Natural gas infrastructure independent technologies include on-site electricity generation, gas-to-liquid technology (GTL), LNG, and enhanced oil recovery. Although the case studies in this paper do not cover all of these technologies, the technologies reviewed are currently the most economically feasible investments considering social and economic conditions in Russia, Nigeria, and the United States. In each region, the price of natural gas domestically versus prices in international benchmark US (Henry Hub), Canada (Alberta) and the UK (NBP) indices allude to whether investments will be for domestic consumption or international export. Especially in producer nations that are energy poor, access to energy from natural gas can accelerate development. Deployment of existing and new natural gas utilization technologies will help to save an average of 150 bcm of natural gas per year (GE, 2011). Utilizing flared gas is an opportunity to create value from what was considered waste.

Figures

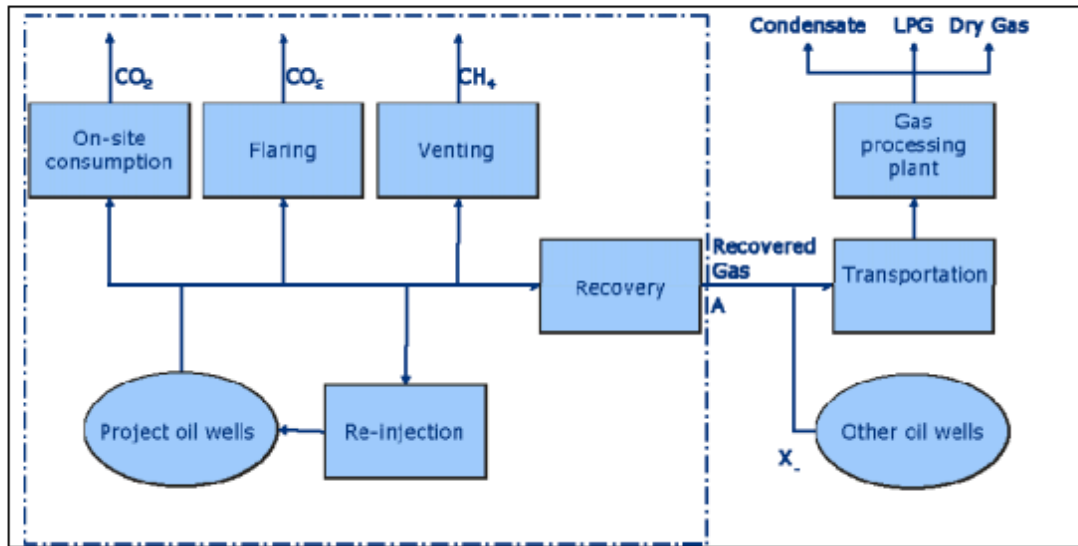


Figure 1: Various modes to utilize associated gas (World Bank 2005).

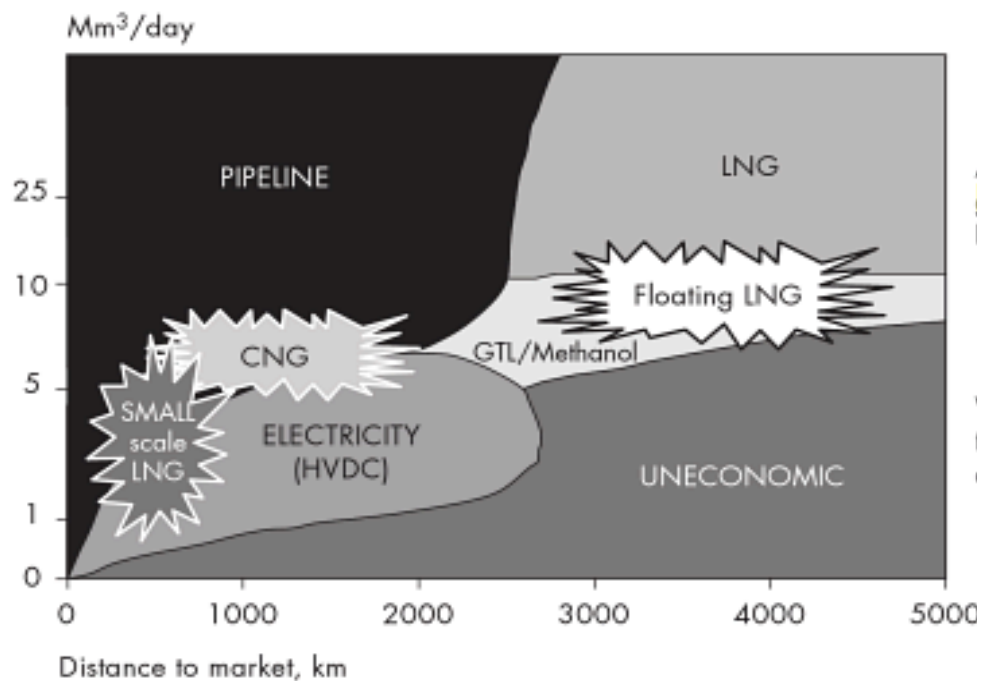


Figure 2: The economics of alternatives for associated gas based on distance from oil field and quantity of associated gas. LNG: liquefied natural gas; GTL: gas-to-liquids; CNG: compressed natural gas; HVDC: high voltage direct current (International Energy Agency, 2006).

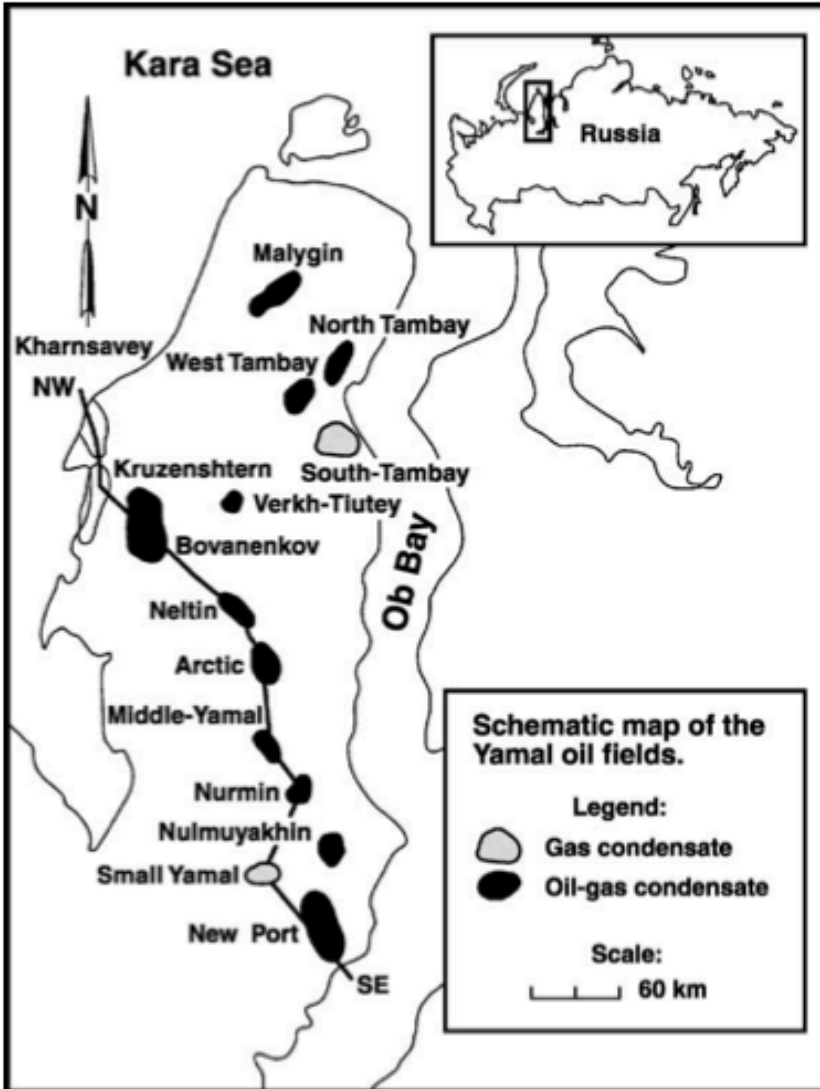


Figure 3: Index map of the Yamal Peninsula, Western Siberia, showing major oil and oil-condensate fields (Chackmekhev, 1994).

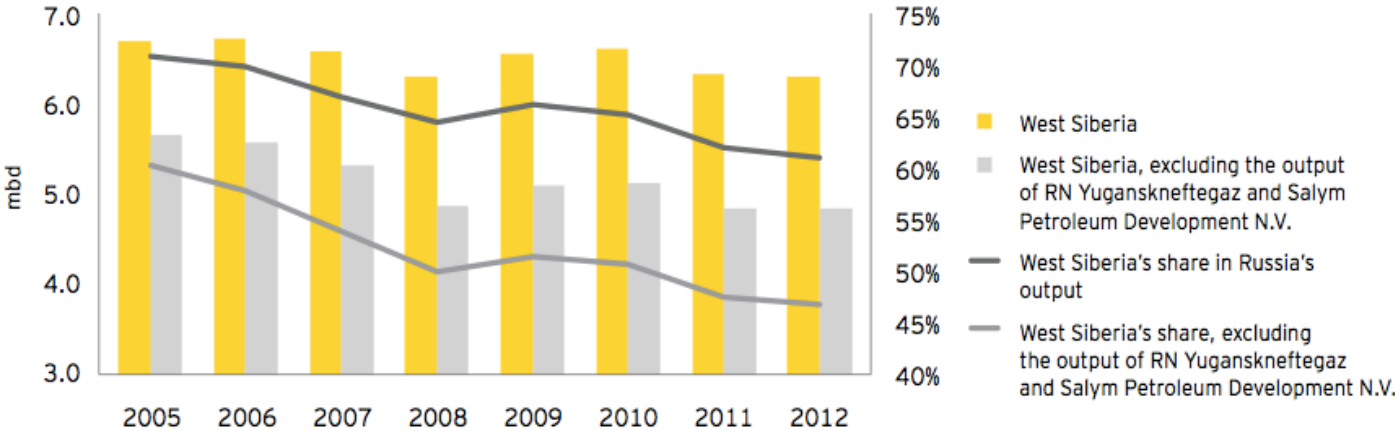


Figure 4: Downward trend in Western Siberia's daily oil production (Ernst & Young, 2011).

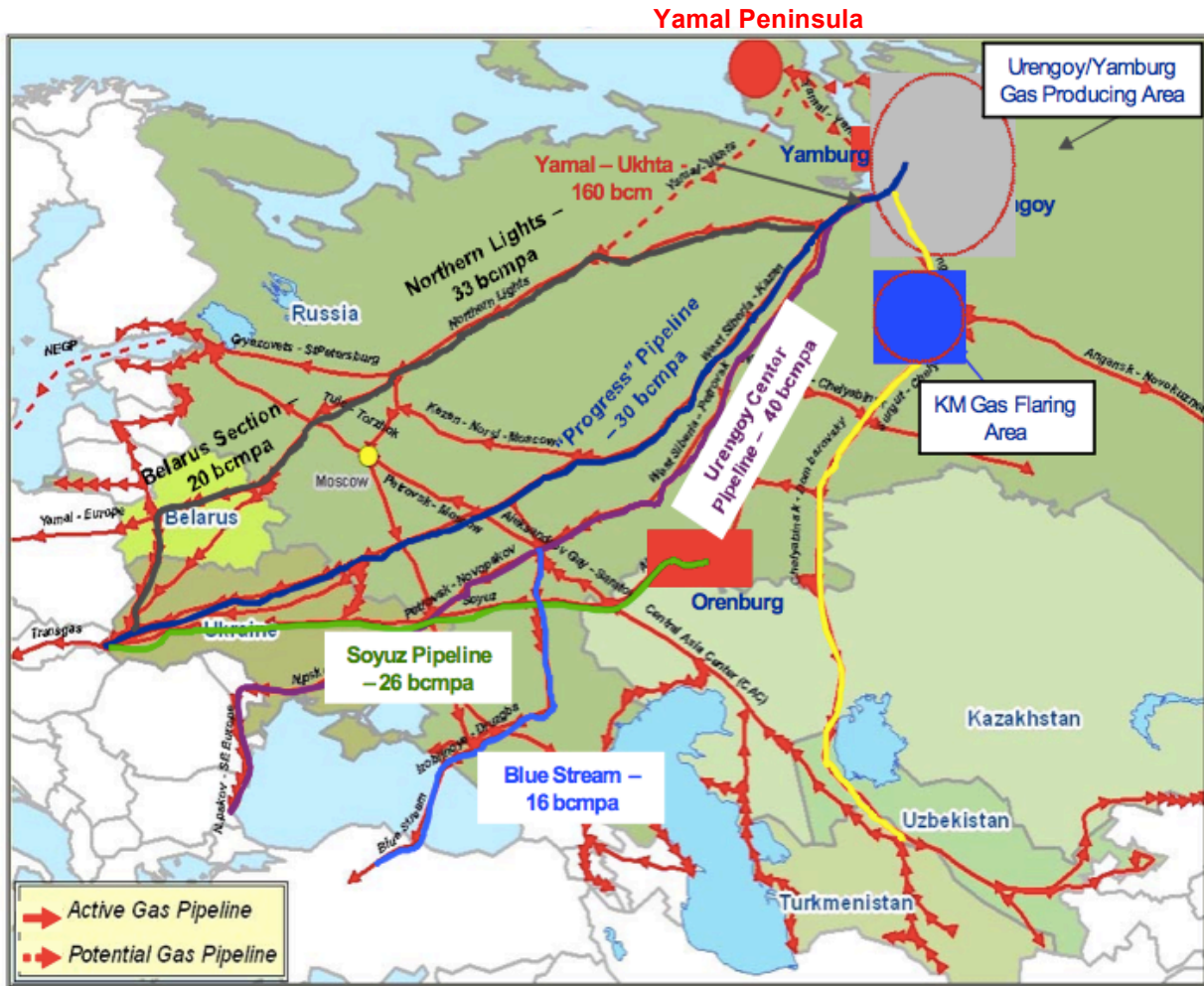


Figure 5: Natural Gas Pipelines and Flaring Region. The Yamal Peninsula is the red dot, northwest of the Urengoy Yamburg Gas Producing Area (PFC Energy, 2007)

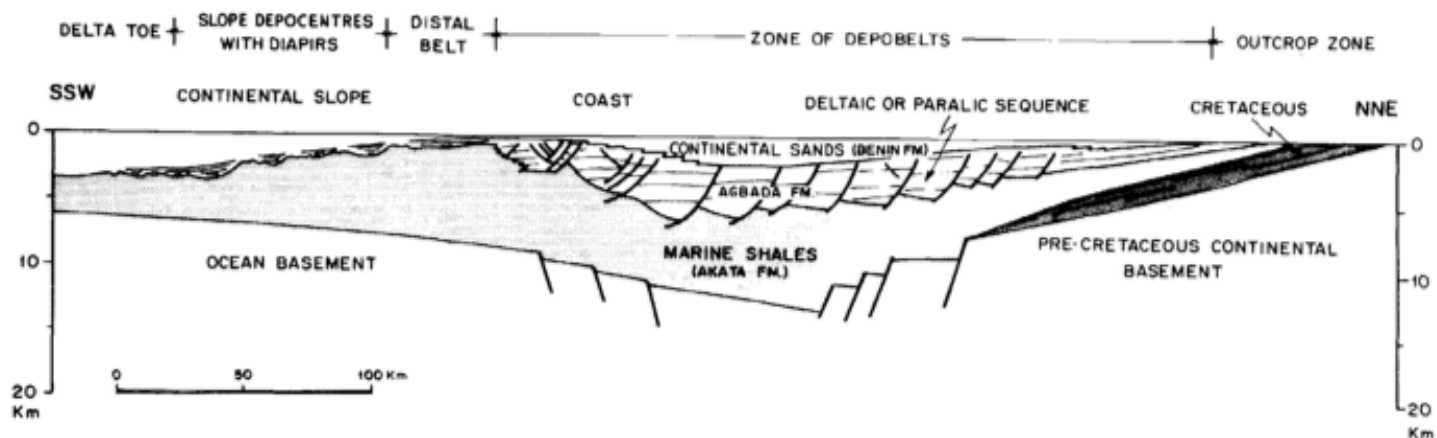


Figure 6: Section through the axial portion of the Niger delta, showing the evolution of a depobelt as younger formations accumulate sediment and is displaced seaward and southward. Vertical exaggeration 5X (Doust and Omatsola, 1989).

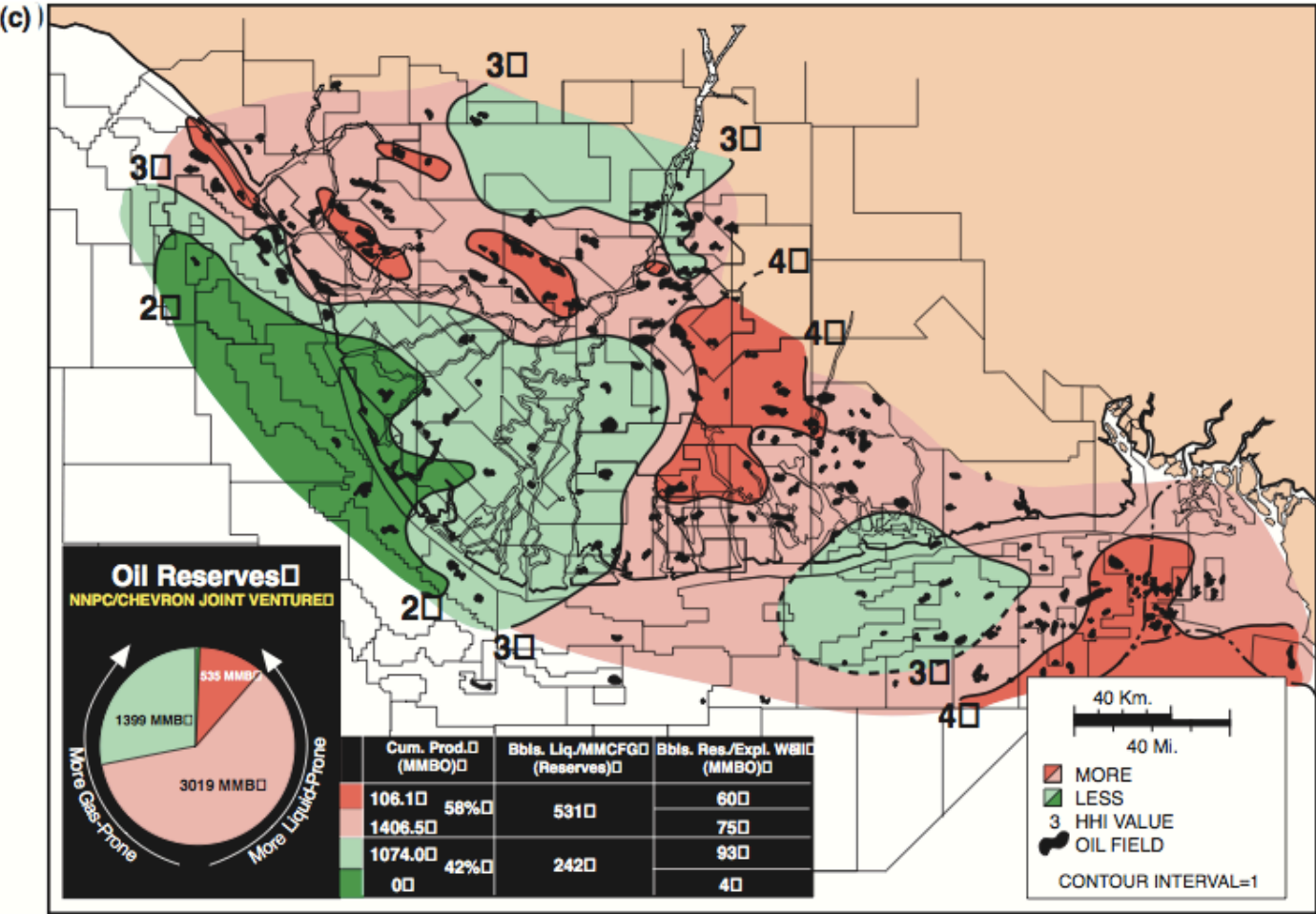


Figure 7: Distribution of more gas-prone fields (Green) near the shore, and more liquid-prone (Red) in the interior of the Niger Delta (Haack et al., 2000).

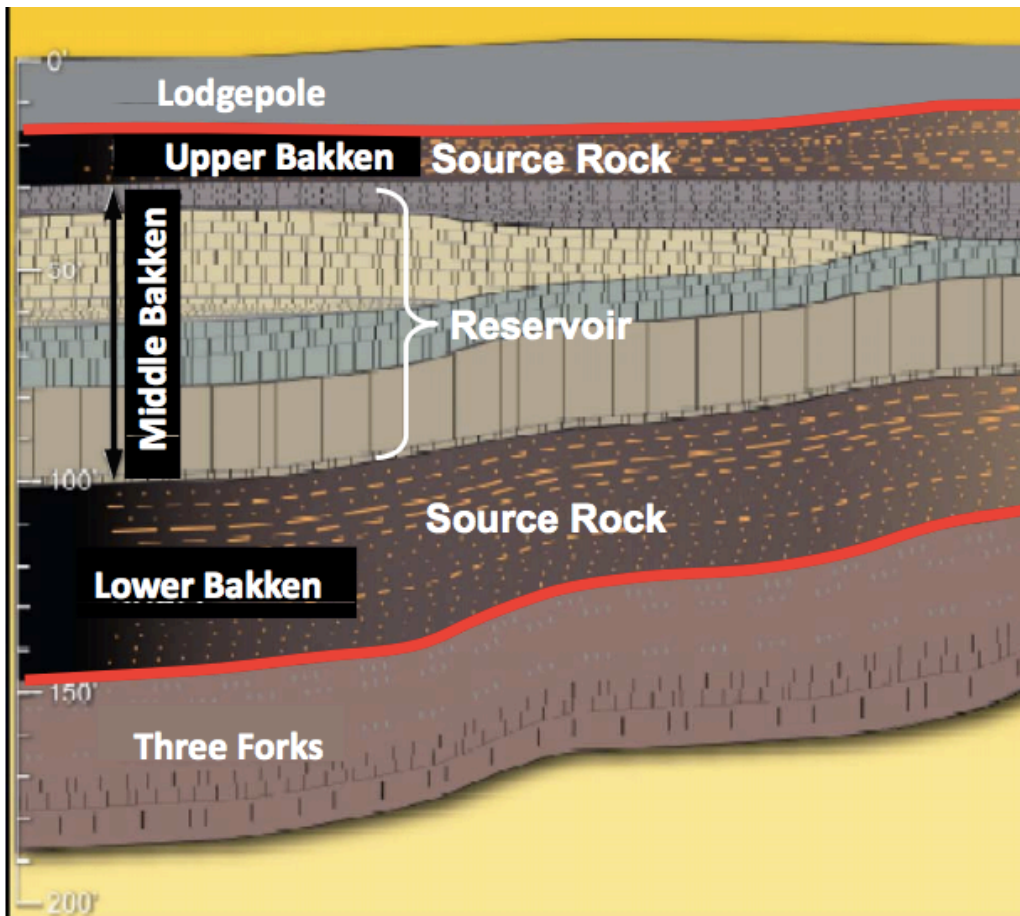


Figure 8: Cross-section of the Bakken Formation. Depth is measured in feet. (Jin, Hui, and Stephen A. Sonnenberg, 2014).

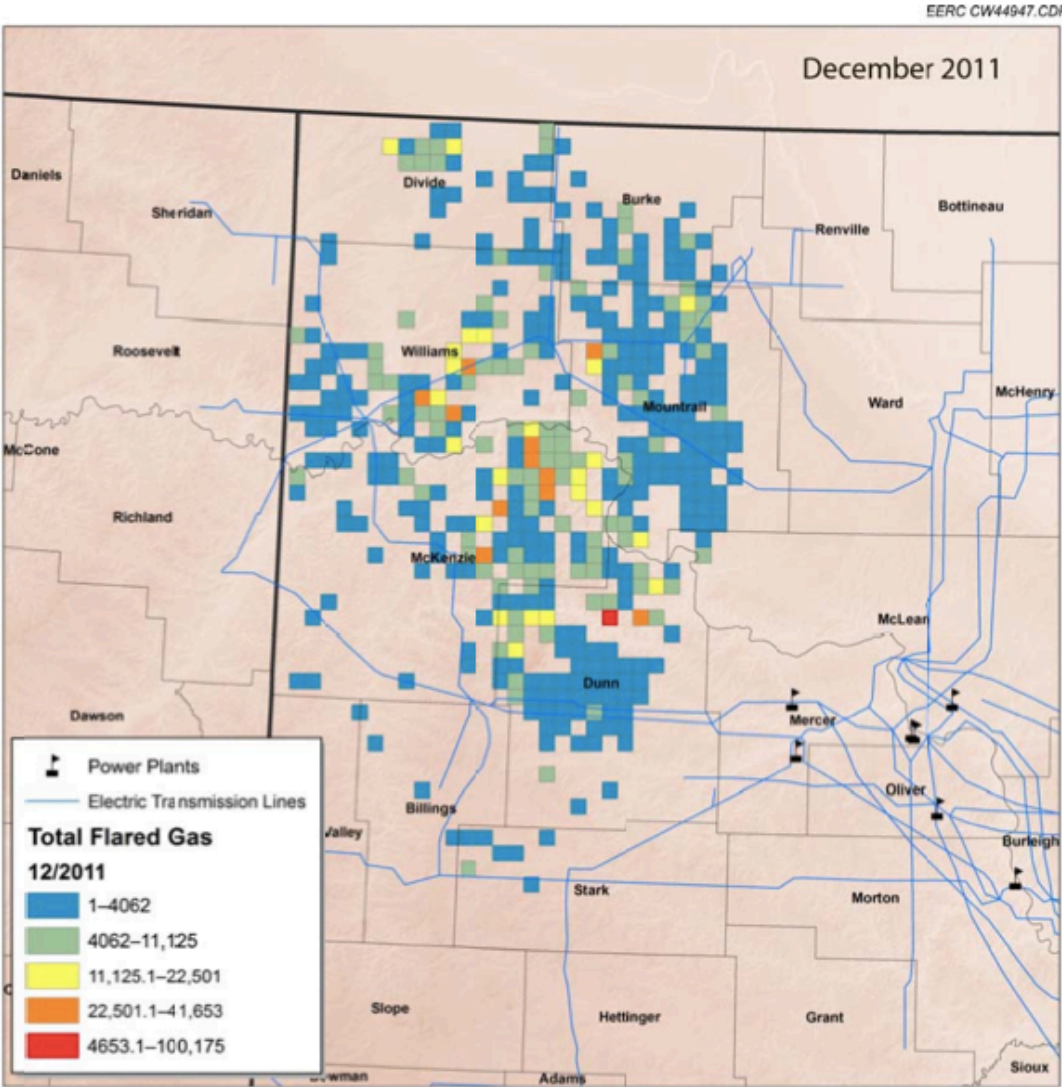


Figure 9: Flared natural gas and existing electrical transmission in North Dakota (Wocken et al., 2013).

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