Using Russia's Associated Gas

Prepared for the Global Gas Flaring Reduction Partnership and the World Bank

By PFC Energy

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Table of Contents

Glossary

Abbreviation	Description
APG	Associated Gas, also called Associated Petroleum Gas
cm/t	cubic meters per metric tonne
Bcm	Billion cubic meters
Bcm/y	Billion cubic meters per year
CCGT	Combined Cycle Gas Turbine
EOR	Enhanced Oil Recovery
GOR	Gas-to-Oil Ratio
GPP	Gas processing plant
GTL	Gas to Liquids
GWh	GigaWatt hours
IRR	Internal rate of return
KM	Khanty-Mansiysk Autonomous Okrug/Region
kWh/t	kiloWatt hours per tonne
LPG	Liquefied Petroleum Gas (usually propane and butane)
Mcm	Thousand cubic meters
md	Milli darcies – measure of permeability
MMbbl	Million barrels
MMcm	Million cubic meters
MMtonnes	Million tones
MWh	MegaWatt hours
TWh	TeraWatt hours
UGTS	Unified Gas System
$/Mcm	US$ per thousand cubic meters
$/MMBtu	US dollar per Million Btu

Executive Summary

According to official data sources, the Russian Federation flared 15 Bcm of associated gas (also known as associated petroleum gas, and abbreviated in this report as APG) in 2005, equivalent to 3% of consumption in the EU-25[1]. Other observers have estimated that the amount of flared gas may be up to four times higher than the official figure. Meanwhile, there is growing concern that in the future natural gas production may not be sufficient to meet both Russia's domestic demand and its growing export obligations. This concern stimulates new interest in commercializing APG that is currently flared. In his April 2007 State of the Union address Russian President Vladimir Putin noted that Russia flares over 20 Bcm/y and announced an intent to make better APG utilization a national priority. Several national and regional government agencies are investigating ways to increase gas utilization and both national and independent oil companies are exploring options for commercializing APG.

In preparation for the Global Gas Flaring Reduction (GGFR) Partnership's forum on Associated Gas Utilization in Russia in October 2007, the GGFR Partnership through the World Bank asked PFC Energy to study gas flaring in Russia and analyze the hypothetical economics of various options to commercialize APG. This report summarizes the findings of that study.

The study estimated that Russia currently flares some 38 Bcm/y of APG, equivalent to about 5% of its total gas production, or 45% of its APG production, and that the amount of flared gas may well increase even as oil production declines.

Comparison between the Russian environment and countries with high rates of APG utilization identified a range of legal, regulatory, and commercial factors that currently limit APG utilization in Russia. These include weak legislation, an ineffective regulatory system, limited midstream infrastructure, low domestic hydrocarbons prices, and effective monopoly positions in the gas processing and transmission industries.

From an economic point of view, the existing technologies that would most efficiently commercialize Russia's flared gas are electric power generation and a combination of gas processing plants (GPP) and dry gas sales. At current APG prices, approximately one third of the currently flared APG could be utilized, resulting in incremental annual revenues of $2.3 billion and eliminating over 70 million tonnes/year of carbon dioxide emissions. Provided that incremental gas transportation and GPP infrastructure is made available. More

[1] Note that this official figure covers only gas with oil production, not gas from condensate stripping

aggressive changes, including higher APG prices, could reduce flaring by approximately 80%, contributing an additional $4.6 billion to $7.1 billion to the Russian economy.

Achieving these savings will require the Russian Government to implement a comprehensive framework of legislation and monitoring and enforcement mechanisms and to oversee creation of market mechanisms that provide appropriate incentives for all the parties, including higher inlet prices at GPPs and more open access to transportation infrastructure.

About this Study

In October 2007, the Global Gas Flaring Reduction (GGFR) public-private partnership coordinated by the World Bank Group co-hosted a forum in Moscow to discuss Associated Gas Utilization in Russia[2]. The GGFR asked PFC Energy to study APG flaring in the Russian Federation and present the results of that study at the forum. The GGFR also intends to provide the study to Russian federal ministries as an aid in developing policies and regulations on gas flaring and gas utilization.

The study included analysis in four major areas:

1. The current environment in Russia
2. How other countries have improved utilization of APG
3. Hypothetical economics of commercializing APG and comparison of alternative uses, including Gas To Liquids (GTL), reinjection for Enhanced Oil Recovery (EOR), power generation, and gas processing
4. Recommendations to reduce flaring and create value for stakeholders in Russia's gas industry.

The study was conducted in a short period of five weeks, using public domain information and PFC Energy's own information and resources. The authors did not have access to data about individual reservoirs, fields, wells, and flaring operations in the Russian Federation. The goal of the study, and of this report, was not to design an optimum gas utilization system, but to provide an overview of the technical, economic, regulatory, and

[2] The Russian Federation does not belong to GGFR, but the Khanty-Mansiysk Autonomous Okrug (KM), one of Russia's major producing regions, is a member.

political issues that affect the flaring and utilization of APG in the Russian Federation and suggest the most productive avenues for future research and policy development.

The analysis uses the following general assumptions:

- All economic analysis is in real terms as of 2007.
- Rubles are converted to US dollars at an exchange rate of 25.5 Rubles per US dollar.
- Discount Rate: 10% in real terms. At Russia's current 9% inflation rate, this equates to approximately 20% in nominal terms[3].
- All calculations were performed on a pre-tax basis.

Section 2 of this report describes gas flaring in Russia today and the factors in the Russian environment that contribute to that flaring. The section includes an estimate of current flaring volumes. Section 3 presents an array of theoretical options for commercializing APG. Section 4 reviews mechanisms used in other oil producing countries to reduce gas flaring. Section 5 summarizes the hypothetical economics of different utilization options. Section 6 suggests policy frameworks to reduce APG flaring in the future. Section 7 provides summary conclusions. Seven appendices provide supplemental information and more detailed analysis.

[3] Nominal IRR = ((1 + real IRR) x (1 + inflation rate)) - 1

1. Introduction

Russia is the world's largest gas producer and second-largest oil producer. In 2006, the country's gas production of 600 billion cubic meters per year (Bcm/y) and oil production of 10 million barrels a day (Mmb/d) constituted 21% and 12%, respectively, of world totals. Many of Russia's oil reservoirs, like those of other producing regions, contain associated gas that travels to the surface when the oil is produced[4]. For reasons that are explained in this report, much of this gas is flared at the wellhead, with the several negative results, including:

Loss of economic value: The Russian Federation Ministry of Natural Resources estimates this loss at $13.5 billion/year.

Emissions of greenhouse gases associated with global warming: If all flared gas is burned, Russia's APG flaring creates carbon dioxide emissions of between 30 and 100 million tonnes annually. When flares do not work effectively, producers may vent methane, a much more potent greenhouse gas than CO_2[5].

Pollution and potential negative health effects: Burning APG can generate other compounds of carbon, sulfur, and nitrogen that cause pollution and health problems.

Loss of gas volumes that could be available for export: Russia enjoys a substantial and growing market for its gas exports and, in fact, imports gas from neighbors to meet that demand. By capturing and using more domestic gas, Russia could increase its supply of gas for export.

The amount of flared gas is not measured, but official estimates that in 2005 Russia flared 15 Bcm of APG, an amount equivalent to the annual gas consumption of Belgium and Luxembourg. President Vladimir Putin, in his 2007 State of the Union speech stated that Russia flares 20 Bcm of APG annually, and made proper utilization of natural gas is a national priority. The Russian Government has announced plans to require producers to

[4] See Box 1 for more information about APG

[5] Methane has a global warming potential (GWP) over 100 years of 23, compared with 1 for CO_2. GWP is a relative scale measuring how much a given mass of any greenhouse gas contributes to global warming compared with the same mass of CO_2, the GWP of which is defined as 1.

utilize 95% of all APG by 2011, but has provided few specifics on how this will be achieved.

Box 1:

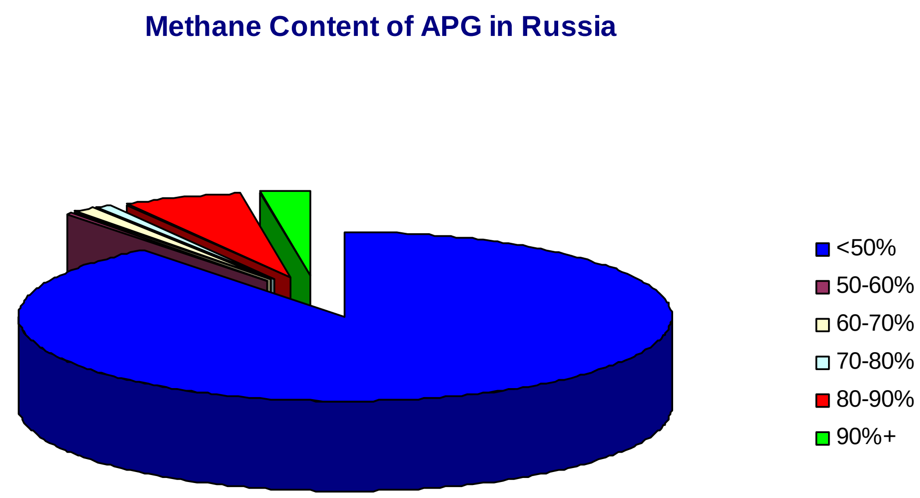
What is APG?

Associated gas (also known as associated petroleum gas and abbreviated in this report as APG) is gas that is associated with the oil in the reservoir[6]. Although this theoretically includes the gas cap (gas residing above oil in a reservoir), the term usually refers only to gas dissolved within the oil. As the oil is produced to the surface, associated gas comes out of solution and is commonly separated before oil enters the pipeline. The amount and composition of APG vary depending on the nature of the oil reservoir, the type of lift that is used, the degree of depletion of the reservoir, and other factors. APG is almost never in the form of pure, clean, dry natural gas (methane) suitable for sale to homes and businesses, but is typically mixed with varying combinations of ethane, butane and propane (Liquefied Petroleum Gas, or LPG), other organic compounds, water, carbon dioxide, hydrogen sulfide, and other impurities. Western Siberian APG typically averages around 60% methane, making it what is known as “rich,” meaning that it has a high liquids content. Rich gas cannot be directly fed into the gas pipeline system, but must first by processed at a Gas Processing Plant (GPP), which separates out liquids and impurities and delivers pure, dry methane to a pipeline. The liquids or condensate can be sold, processed into LPG (typically used for cooking, heating, or fueling vehicles), or further processed into more expensive petrochemical feedstocks.

Even reusing APG at the well site, for instance for reinjection or power generation, usually requires some processing to remove corrosive elements and create a uniform mixture, in addition to compression to a required pressure.

[6] This report addresses only associated gas, not gas from condensate stripping, which may also be flared

Chart 1.1



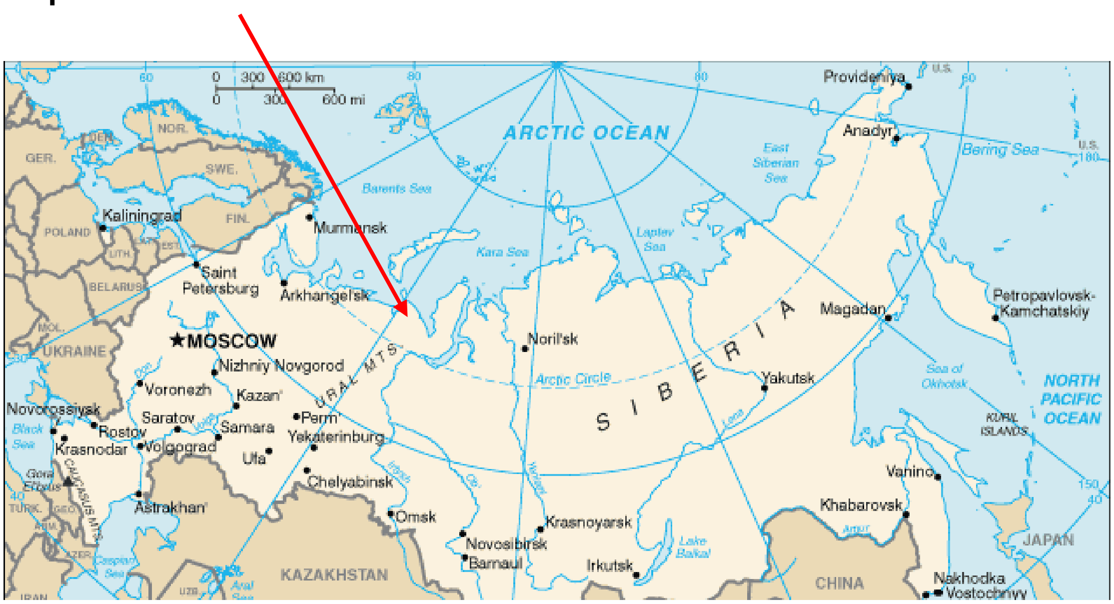
2. The Current Environment

This section surveys the current environment in Russia, including the geography of APG flaring, the amount of gas that is flared, and the reasons why this occurs. Topics covered include the legislative and regulatory environment, key commercial conditions, and relevant markets and pricing.

2.1 Geography of Russian Gas Flaring

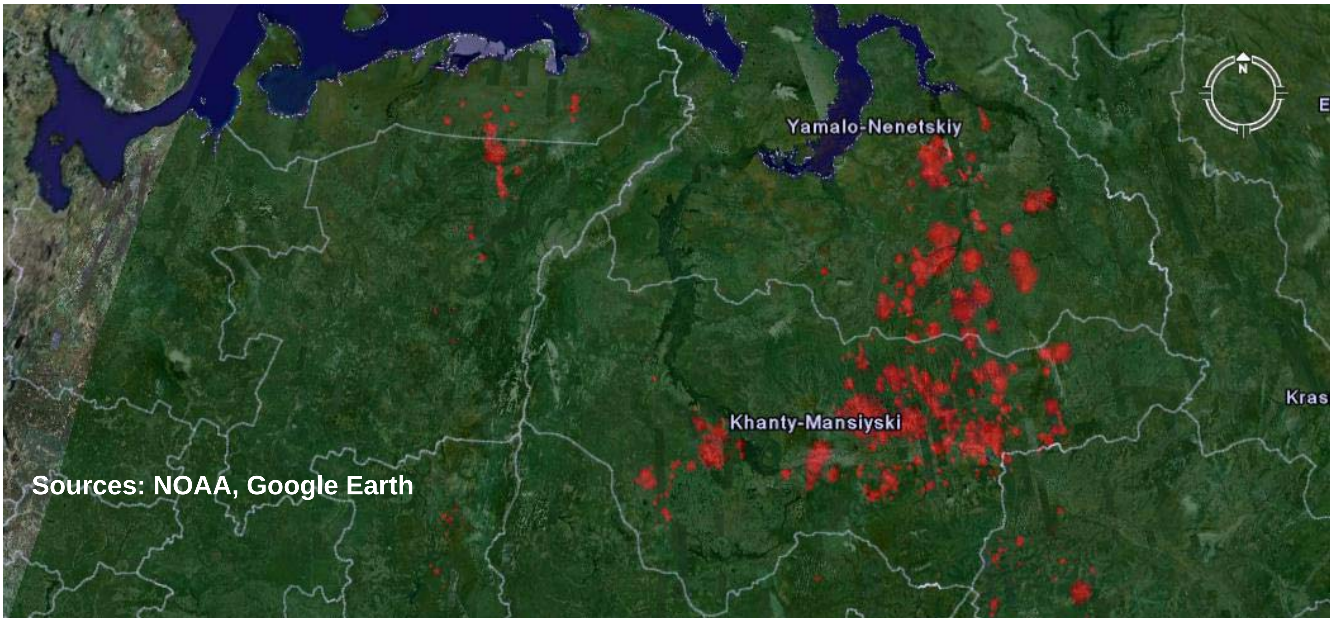
Russia is the world's second largest oil producer, with 12% of world production, and holds 7% of the world's proven oil reserves, making it the seventh-largest reserve-holding country[7]. About 40% of Russia's recoverable oil reserves are located in fields that have APG. Most of Russia's gas flaring takes place in the Khanty Mansiysk (KM) and Yamalo-Nenetsk (YN) regions of Western Siberia, within a 600,000 km^2 region (larger than France). The region lies within 500 km of the giant Urengoy and Yamburg gas fields, which are the main suppliers of the gas pipelines serving European Russia, Western Europe, and the countries in between, and within 250 km of Russia's existing gas trunklines. The gas flaring region is also served by a local infrastructure of pipelines and gas processing plants.

Map 2.1: General Location of APG Fields

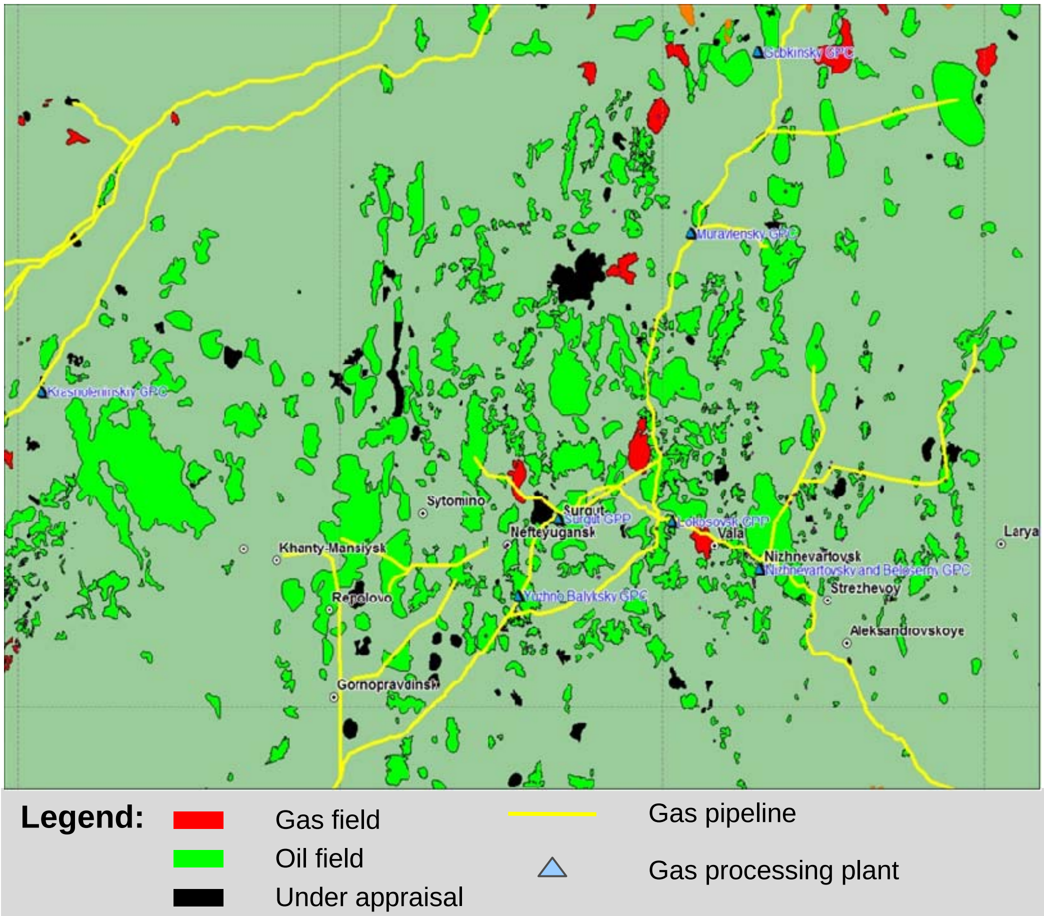


[7] BP statistical Review 2007

Map 2.2: Satellite Image of Russian Gas Flaring



Map 2.3: APG Flaring Region



Source: Petroview and PFC Energy

Russian oil fields average 20-50 Mmbbl in reserves. Charts 2.1 and 2.1 below show PFC Energy's estimate of how flared gas volumes are distributed by field[8]. While ten major fields flare half of Russia's APG, half the fields are estimated to be flaring less than 0.005 Bcm/y. This small average volume makes it expensive and technically challenging to utilize APG on any scale.

[8] See Appendix A for PFC Energy's estimation methodology.

Chart 2.1

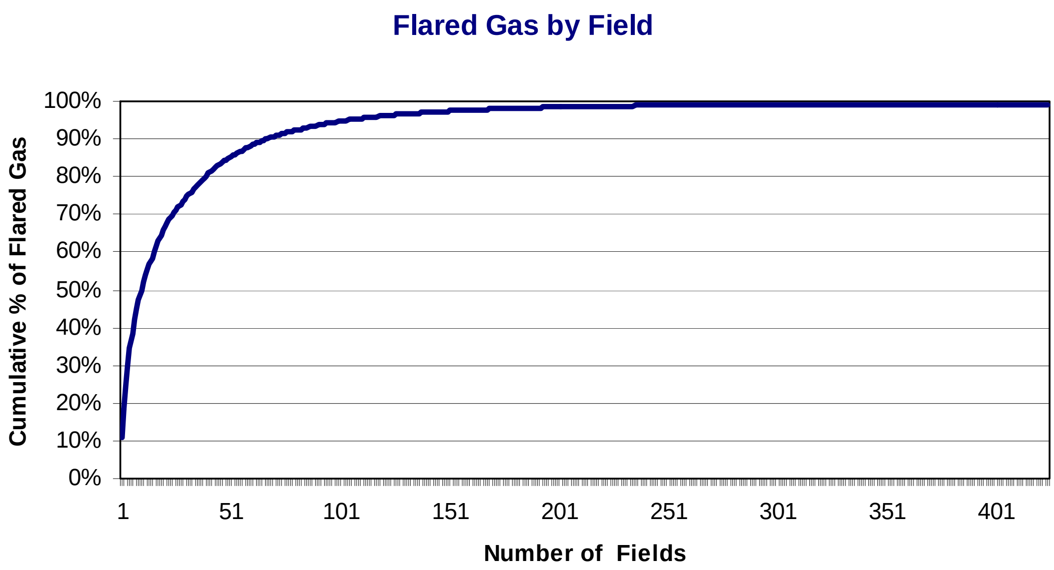
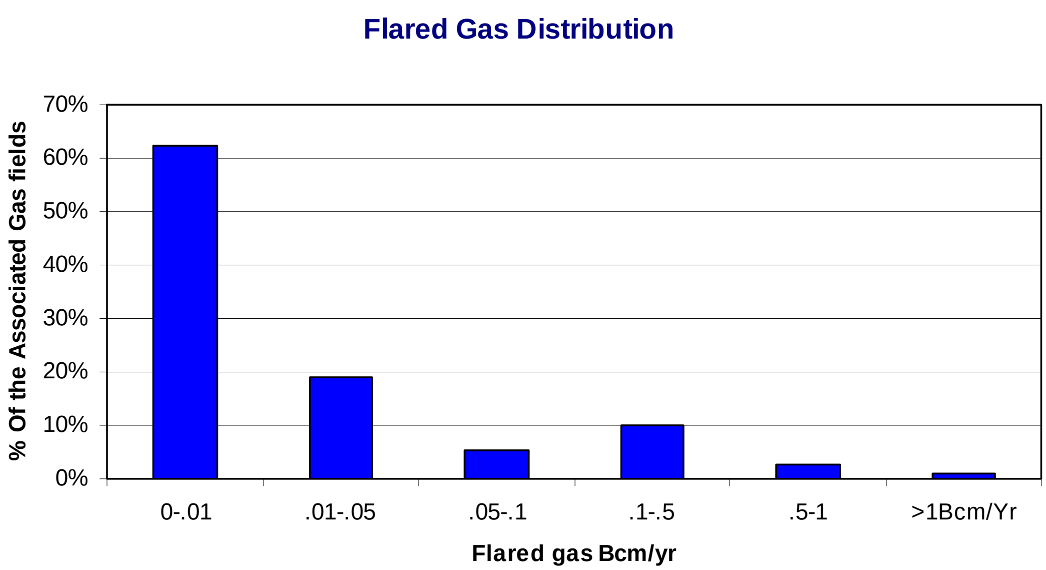


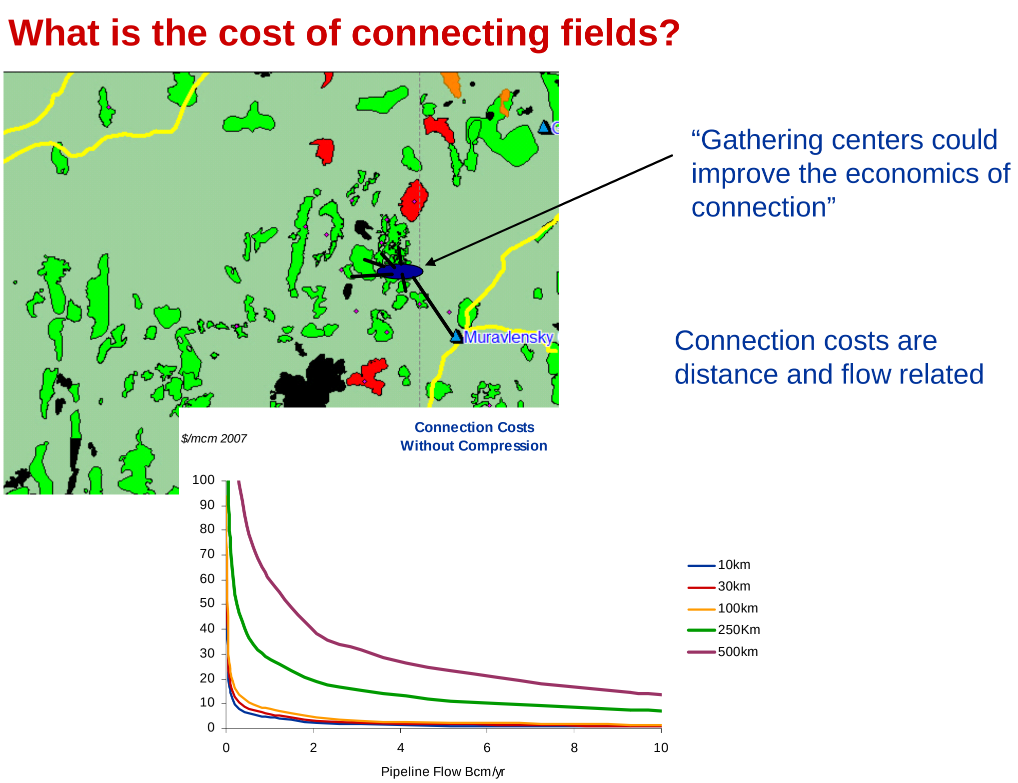
Chart 2.2



2.2 Connection Costs

With such a diverse spread and composition of fields, no one size fits all. Developing such fields with the use of GPP's will require pipeline connections possibly over distances of over a 100 km. The cost of these connections will depend upon both flow (Bcm/y), distance, and the need for processing or compression. PFC estimates (Figure 2.1) that these costs could range between \$5/Mcm – \$120/Mcm[9]

Figure 2.1



It is key therefore that for very small fields that they pool volumes to essentially increase economies of scale and reduce unit investment costs. On a weighted average basis the connection costs of fields in the KM area is

[9] Depends on flow and distance and assumes no compression or additional processing. PFC Energy estimate based on capital and operating costs requiring a 10% real rate of return

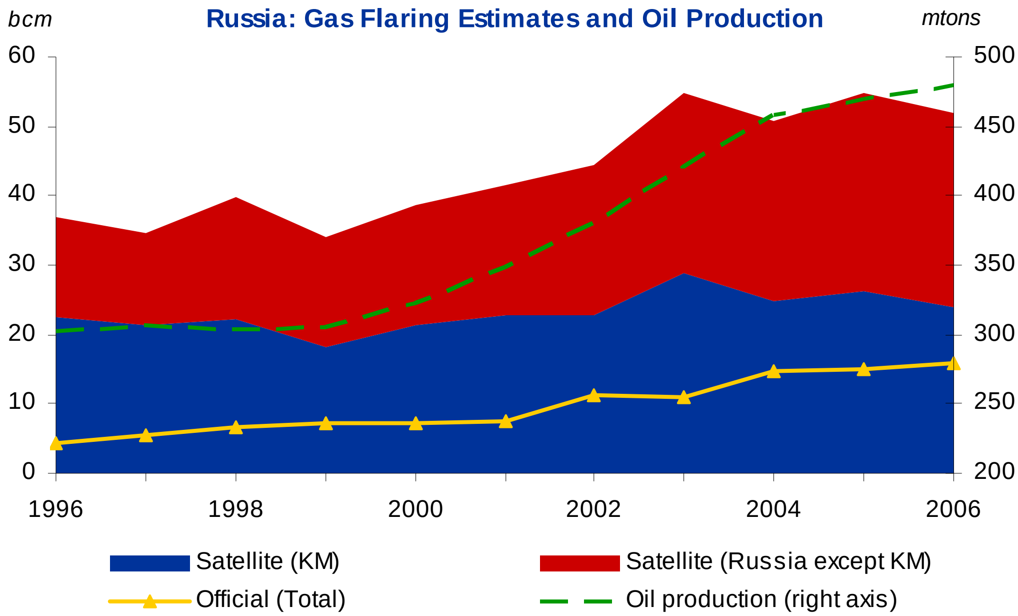
around $27/Mcm.

2.3 Estimate of Flared Gas Volumes

Chart 2.3 shows several estimates of Russian APG flaring volumes, with oil production volumes added as a comparison on the right hand scale.[10] According to official statistics, Russian oil producers flare a total of 15 Bcm/y of APG. Vladimir Putin's 2007 State of the Union address quoted a figure of over 20 Bcm/y. A 2006 study by the International Energy Agency (IEA) used satellite data and data from the US National Atmospheric and Oceanic Administration (NOAA) to estimate that approximately 60 Bcm/y of APG and gas from condensate stripping are flared in Western Siberia.

[10] Like most discussions of gas flaring in Russia, this report assumes that all APG is burned at the wellhead. Anecdotal evidence suggests that because of technical problems with burners and ignition systems not all gas is burned and some is vented—i.e. emitted as methane rather than burned to yield CO_2 and water vapor. This is typically the result of flare design inefficiencies. In addition there is also some deliberate venting of gas without burning. The lack of metering and reporting systems makes it impossible to estimate how much gas is vented rather than flared.

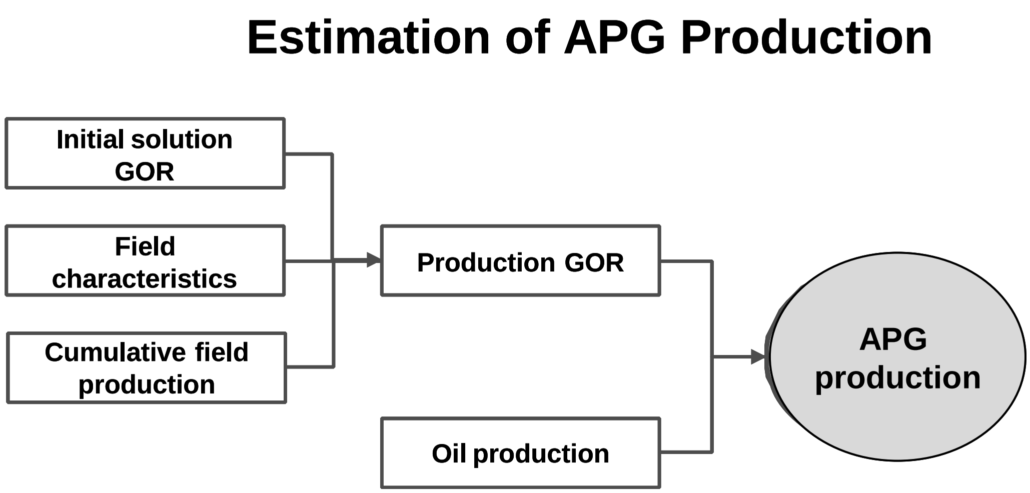
Chart 2.3



Source: IEA, NOAA, World Bank, Ministry of Energy of the RF, RIA TEC

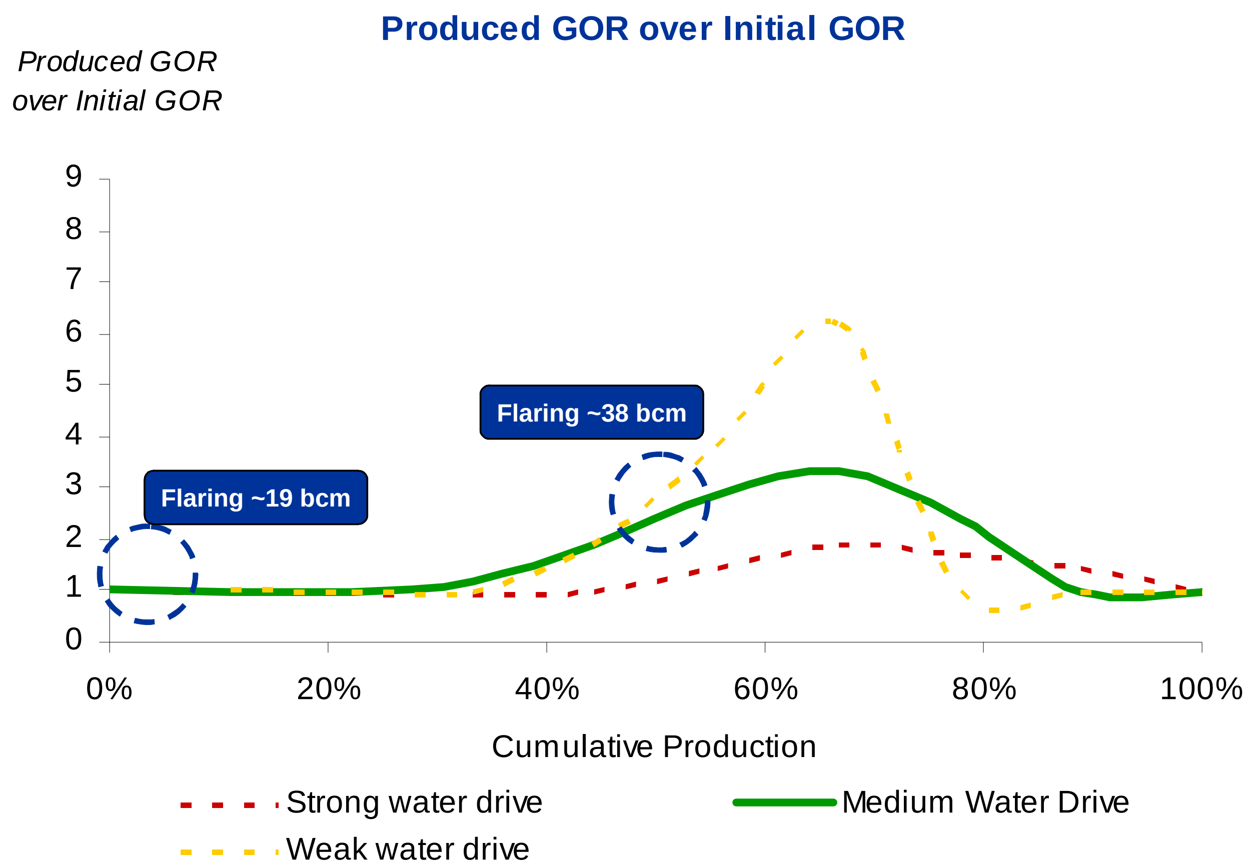
Since APG is not measured at individual Russian wellheads, it is impossible to state independently and conclusively how much APG is flared, but it is possible to estimate this quantity based on known characteristics of Russian oil production. PFC Energy estimated the amount of APG produced in Russia using a field-by-field model that includes oil production, the ratio between the amounts of gas and oil produced in a field (Gas-to-Oil Ratio or GOR), and the production profiles that fields of different characteristics display over time. A more detailed description of this estimation process is provided in Appendix A.

Figure 2.2



The ratio of gas produced from a field is not constant, but increases during a field's early life and decreases at the end of its productive life. The exact pattern of this increase and decline depends on the nature of the field's drive mechanism, or the way in which pressure is maintained in the reservoir, most commonly as a result of water flowing in as oil is removed. Chart 2.4 shows the GOR profiles (expressed as the ratio of production GOR to initial solution GOR) for a range of typical water drives: weak, medium and strong. The "medium water drive" curve best approximates the behavior of the oil fields of Western Siberia. For these fields, the *production* GOR peaks at more than three times initial rates when production reaches 65% of the field's total. It seems probable that lower-end estimates of Russian gas flaring are based on *initial solution* GORs and assume a constant ratio between oil and APG production over the life of each field.

Chart 2.4



Source: Recreated from Muskat, M. *Physical Principles of Oil Production*, 1947

Based on the "medium water drive" profile, PFC Energy estimated that the volume of APG flared is several times higher than the low estimates, or approximately 38 Bcm/year. This volume, which is about 45% of Russia's total APG production, is equivalent to 5% of Russia's total marketed gas production or 8% of EU-25 gas consumption.

The analysis also leads to the conclusion that APG output in Russia may well increase even as oil production declines. APG production profiles at individual fields will vary, and understanding these individual profiles will be important in planning any future commercialization of flared gas.

2.4 Current Barriers to Utilizing APG

At first glance, it may seem surprising that so much potentially valuable energy—equivalent, as has been stated, to 8% of the EU-25 gas consumption—is wasted. The situation persists because of a combination of economic, structural, political and other factors, which are explored in this section. These barriers are:

Geographic

- Although the majority of oil fields are in the same general region as existing gas fields, the region is vast and connection distances to existing gas infrastructure can be substantial.
- Significant volumes of APG are produced from small fields in thinly populated regions that are remote from major gas markets;
- This results in high unit connection costs for many of the fields.

Legislation and Regulation

- Federal law has not historically required companies to minimize gas flaring, although this will soon change;
- Where hydrocarbon licenses include gas utilization requirements, these are rarely enforced;
- Fines, if any, for gas flaring are small and capped at only $1,540 per year;
- There is essentially no government monitoring of gas flaring levels.

Structural

- Gazprom has a monopoly on gas transportation and other gas producers do not have transparent, neutral, and regulated third-party access to the pipeline network;
- One company, Sibur Holdings JSC, which is 100% owned by Gazprom, has a *de facto* monopoly on independent gas processing in Western Siberia;
- Gazprom has a monopoly on gas exports from Russia.

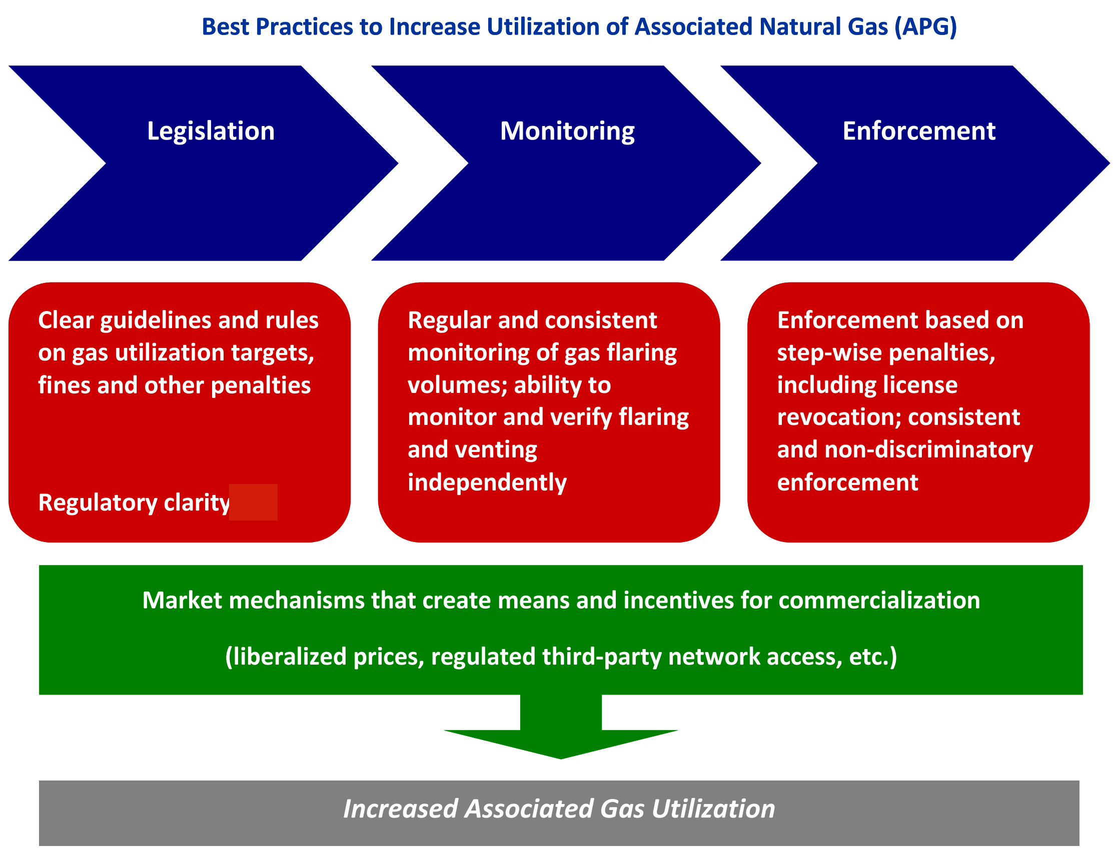
Economic

- Russian domestic gas prices have historically been too low to stimulate the investments needed to increase APG utilization.
- Gas prices remain quite low, averaging $45/Mcm, compared with $140-280/Mcm in world markets.
- Inlet prices for raw APG at gas processing plants are low.

The most significant of these barriers are described below in greater detail.

2.5 Legislation and Regulation

Figure 2.2



Successful policies to reduce or eliminate gas flaring have three main components: legislation, monitoring, and enforcement. These policies must be complemented by market mechanisms that create both the means and the necessary incentives to utilize APG. Although the government of the Russian Federation has taken concrete steps to address gaps in the system, the current legislative and regulatory environment does not promote maximum utilization of APG.

Legislation

Russian federal law does not require APG utilization or limit gas flaring. The government has announced plans to legislate that oil producers increase their utilization of APG to 95% by 2011, but has not yet introduced specific legislation. Some regions have created their own rules, a process that has been irregular and slow. The two main gas-flaring regions—Khanty Mansiysk (KM) and Yamal-Nenetz—have made gas flaring provisions a standard part of their licenses. KM has established a 5% limit on gas flaring, but allows operators to exceed it if they can demonstrate that utilization is uneconomical. According to the KM regional administration, only 26% of its 213 licenses were in full flaring compliance in 2005.

Monitoring

Since many licenses contain no gas utilization requirements, there is little incentive for accurate metering of associated gas utilization and flaring. Technical standards are inconsistent and many fields lack metering devices altogether. Government agencies do not regularly monitor the accuracy of reported flaring figures, leading to widely varying estimates. The federal government has recently taken steps to improve the situation, beginning with an announcement on 14 August 2007 that Rosteknadzor, the industrial inspectorate, will audit all existing gas flaring systems by March 1, 2008. The process is to begin in KM in September and October 2007. A major cause of the poor monitoring and enforcement of Russian gas utilization is the unclear division of authority between federal and regional authorities.

Enforcement

Enforcement responsibility rests with multiple agencies, poor monitoring limits the information available to regulators, and existing enforcement tools are insufficient to stimulate APG utilization. Associated gas currently bears a zero percent mineral extraction tax, compared to 147 Rubles/Mcm ($5.67) for produced natural gas. Producers violating flaring limits can be charged emissions fees, but these fees—20 Rubles per Mcm ($0.77), up to a maximum of 40,000 Rubles annually ($1,540)—do not impose a serious financial burden. Nor is there a clear sequence of punishments that provide incrementally stronger incentives to reduce gas flaring. In Alberta, Canada, for example, the clear, step-by-step approach can ultimately lead to revocation of an operator's license.

The Russian government has taken several steps to improve enforcement. In July 2005, Rosteknadzor and the Ministry of Economic Development and Trade (MEDT) increased fees for methane emissions, including flaring, by a factor of 1,000, albeit from a very low base. According to the new mandate, operators will pay 50 Rubles per tonne for emissions below permitted limits and 250 Rubles per tonne for emissions above those limits. In June 2007, as part of its ambitious goal of reaching 95% utilization of APG by 2011, the Ministry of Natural Resources announced plans to increase flaring fines five-fold starting in 2009. A draft bill in the Duma would also require oil companies that use less than 95% of APG to pay a mineral extraction tax.

2.6 Commercial Environment

Two features of Russia's current commercial environment inhibit APG utilization. These are (i) infrastructure constraints that prevent oil producers bringing their gas to market and (ii) subsidized energy prices that reduce the incentive to commercialize APG.

Infrastructure: Pipelines

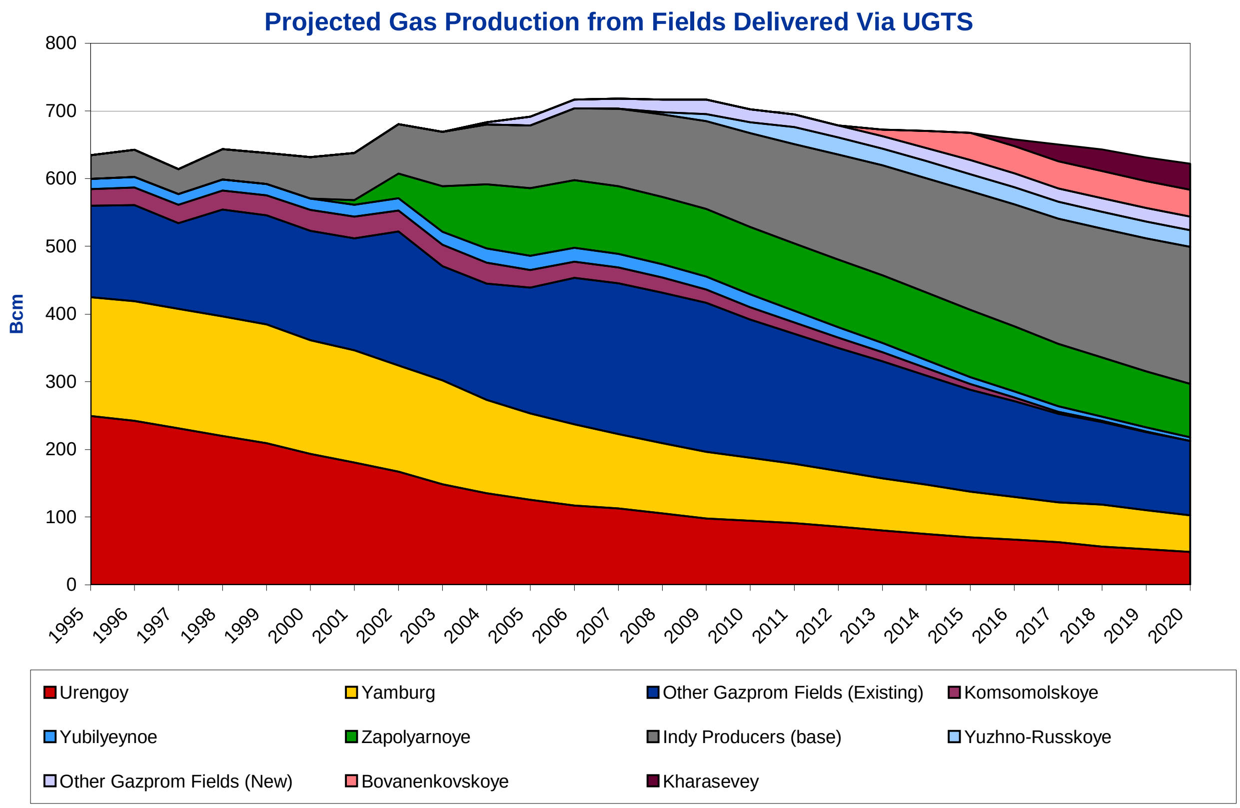
One of the key requirements for gas commercialization is third-party access to the gas transmission infrastructure. Without it, producers cannot directly market their gas or enter into long-term contracts that depend on reliable pipeline delivery.

A 2004 report from the Organization for Economic Cooperation and Development (OECD) found that, "The domestic gas market is not really a market at all. It is rather a rationing mechanism with market-based activity at the fringes."[11] Russia's gas industry is dominated by Gazprom, a majority state-owned company that produces approximately 85% of the country's gas output and enjoys a monopoly over gas transportation and exports. Russian law allows independent oil and gas producers to market gas directly to power plants, industrial users, and petrochemical producers, but to do so they must negotiate pipeline access with Gazprom. Government Decree No. 858 of July 14, 1997 gives third parties the right to nondiscriminatory access to spare pipeline capacities, provided their gas is of the requisite quality. In practice, Gazprom can deny access by claiming that there is no spare capacity available or that the gas does not meet its specifications. No independent regulatory authority systematically monitors pipeline access and the process for challenging a decision by Gazprom is

[11] OECD, "Reforming the Domestic Natural Gas Market," in OECD Economic Survey of the Russian Federation 2004, available online at http://www.oecd.org/dataoecd/56/4/32389306.pdf

burdensome. Market participants have complained that access to Gazprom's pipelines is irregular and allocated through a non-transparent process and the Federal Anti-Monopoly Agency (FAS), to which independents producers can appeal if they believe they have been wrongly denied access to the network, noted in a 2004 investigation that Gazprom must pay greater attention to the issue of third party access. Although an August 2007 proposal by the Ministry of Industry and Energy has suggested giving APG priority access to Gazprom's pipelines, access is unlikely to improve without independent supervision and enforcement.

Chart 2.5



Source: PFC Energy

Gazprom's existing Western Siberian pipeline system is well located for transporting commercialized APG but, even with open access, may not currently have the spare capacity to transport the approximately 22 Bcm of dry gas that is contained in Russia's estimated 38 Bcm of flared gas[12]. The Western Siberian gas fields that feed

[12] Assumes 60% methane content; 22 Bcm is 60% of 38 Bcm

these trunklines are, however, in quite sharp decline. As shown in Chart 2.5, PFC Energy's field-by-field analysis projects that by 2010 Gazprom's pipelines will begin to have unused capacity and that this amount could grow to 20-40 Bcm by 2020. The commercialization of APG could then provide valuable additional gas supplies that would utilize Gazprom's existing infrastructure and help it supply its growing market commitments. Appendix B presents more detailed information on current and future Western Siberian gas production and pipeline utilization. In the short term 2008 - 2011, there would be little spare capacity in the system to evacuate the APG. The question then becomes how to capture this APG.

PFC Energy conducted a comparative analysis of the total costs and revenues that can be earned depending on how Russia allocates its scarce trunkline capacity. Two comparisons were made, one with gas produced at gas fields in the Urengoy area, and the other with potential future gas production from the Yamal Peninsula. The analysis assumes that planned APG flaring restrictions will cause oil production to be shut in at fields with flared APG. The analysis (shown in Tables 2.1 and 2.2 below) shows that whereas using the capacity for APG brings added costs for gathering pipelines and gas processing, it also yields substantial additional revenues from sales of oil as well as export gas. As a result, it is economically preferable (for Russia as a whole) to reduce gas shipments from the Western Siberia gas fields to make space for shipping dry gas extracted from APG that is currently flared. Similarly, exporting dry gas from APG produces a higher net benefit per unit of gas than developing gas fields on the Yamal Peninsula.[13] [14]

[13] Analysis performed on a unit cost basis. *Connection cost based on weighted average of KM fields. ** Oil revenue expressed as an equivalent gas unit cost. Average KM GOR of 700 assumed (estimated on a weighted average basis). Cost of a new line to connect to Urengoy has been included. All economics have been performed at 10% real discount rate. Note assumes that oil will be shut in, because of restrictions on APG flaring.

[14] PFC Energy estimates. If Yamal cost 20% less, Russia would be indifferent about using APG over Yamal gas. Note that this analysis does not take account of oil revenues lost through shut in.

Table 2.1

Cost/revenue on unit basis

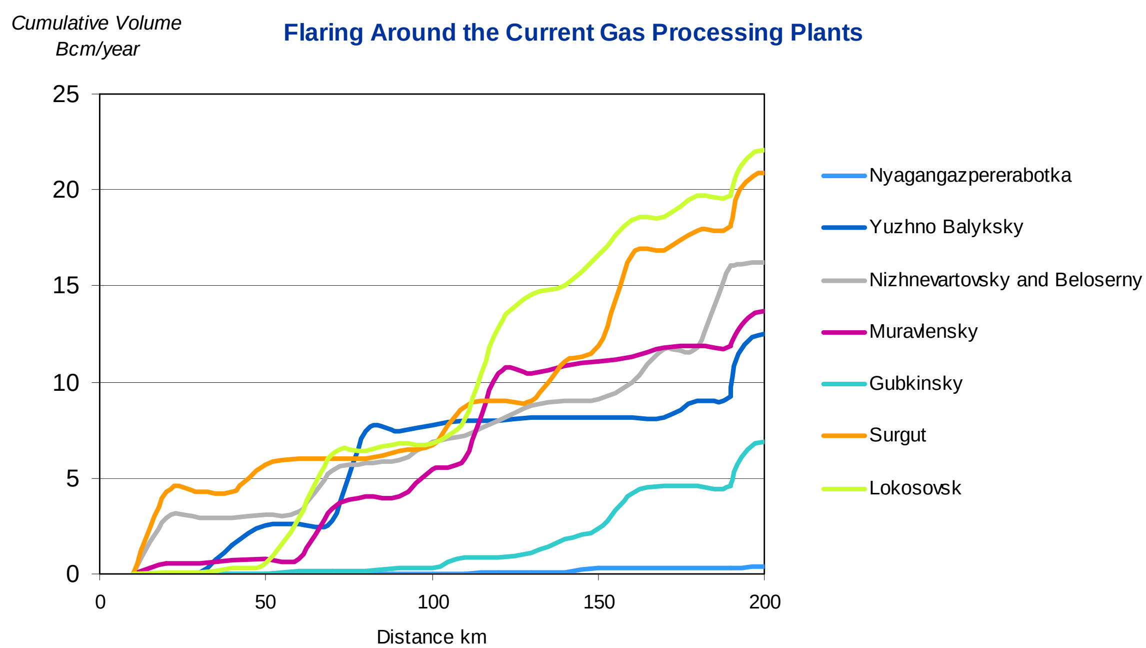
	Yamal $/Mcm	**Urengoy Area $/Mcm**	**APG $/Mcm**
Production cost	198	20	0
Connection cost*	n/a	n/a	27
GPP Cost	n/a	n/a	76
New line	n/a	n/a	4
Trunk line/Transmission	n/a	65	65
Export Price	212	212	212
Oil Revenue $/Mcm **	n/a	n/a	1160
Margin $/Mcm	**14**	**126**	**1200**

Infrastructure: Gas Processing Plants (GPPs)

Another key to commercializing associated gas is providing access to gas processing plants. APG can only enter the pipeline system when it has been "stripped" of its liquids in a gas processing plant (GPP). Western Siberia's GPPs are located in the same general area as most of the currently flared APG, with most flaring taking place within 160 km of an existing plant, as shown in the chart below[15].

The region's dominant gas processing company is Sibur Holding JSC (Sibur), a 100% subsidiary of Gazprom, which owns six GPPs. Two are owned by the producing companies Surgutneftegaz (Surgut GPP) and Lukoil (Lokosovo GPP).

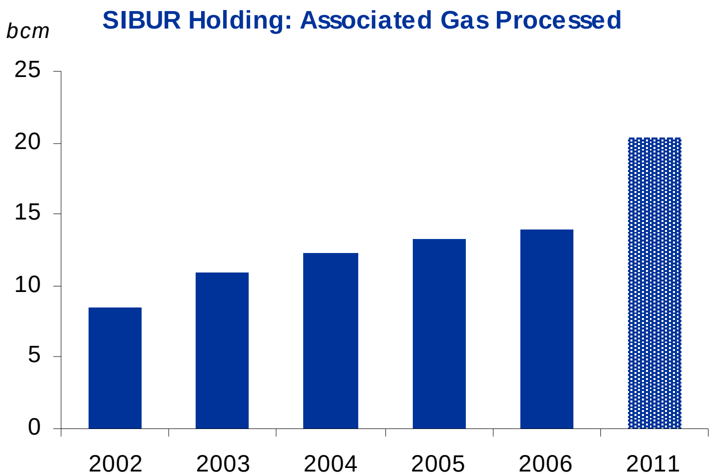
Chart 2.6



Source: PFC Energy

[15] Note that because the chart shows the distance from each flare site to each GPP cumulative volumes cannot be added to obtain total flow volumes

Chart 2.7



Sibur's plants have a combined nameplate capacity of 23 Bcm/y, but appear to have effective capacity of around 14 Bcm/y because they are twenty or more years old and have not been well maintained, and are operating at this level. Sibur has announced plans to expand capacity to 20-21 Bcm/y by 2011 through 4 Bcm/y of expansions, the modernization of the existing Nyagan GPP, and construction of one new 2 Bcm/y plant.

PFC Energy's analysis of Sibur's published financial statements finds that gas processing is a highly profitable business for Sibur, with estimated profit equivalent to $25/Mcm processed, that expanding it is consistent with the company's strategic plan and financial capabilities, and that the company earns additional profits of approximately $15/Mcm from further processing of associated liquids into petrochemical feedstocks. Additional information about gas processing and Sibur is provided in Appendix G.

Energy Prices

Three key prices affect the commercial viability of the direct utilization of APG: the price of dry natural gas, the price GPPs pay producers for APG, and the price GPPs earn from the LPG they extract from APG.

Gazprom sells Western Siberian gas in Western Europe for prices that range from $140-280/Mcm. These prices are not available to other producers, however, because Gazprom by law has a monopoly on all export markets. While other producers are theoretically free to sell directly to domestic customers, any gas they sell must be transmitted through a pipeline system that is also monopolized by Gazprom. The difficulties involved in accessing capacity on this system have already been discussed. In effect, therefore, Russian suppliers today have few realistic options to selling their gas to the domestic market for prices that are believed to average $45/Mcm.

Since Gazprom's pipelines only accept gas that meet certain specifications, most producers cannot sell to Gazprom directly at any price, but must either sell to an existing GPP, that strips out liquids and then sells on dry gas to Gazprom or another customer, or build their own GPP.

Until recently, the prices Russian GPPs paid producers for APG were set by federal government decree, and the schedule in force since 2002 set a price of $9.06/Mcm for typical APG in Western Siberia[16]. In January 2007, the ministry proposed increasing this price to a range of $15.38 - $20.78/Mcm. According to Russian sources, it is more likely that the government will cease attempts to regulating APG prices, which are now effectively set by negotiations between GPPs and producers. In analyzing the economics of commercializing APG through GPPs, PFC Energy has used several inlet prices, including $20/Mcm.

The economics of GPPs are highly dependent upon the revenues they receive for sales of LPG. In Russia today, the federal government regulates LPG sales to the wholesale residential market, which are currently priced at $137/tonne. Some 80% of the Russian LPG market, however, operates under an unregulated pricing regime in which prices typically average $400/tonne. There is essentially no LPG export market since exports require approval from the Ministry of Industry and Energy, which only allows LPG exports after domestic quotas "based on the volumes of demand and consumption" are met.

The trends in Russian pricing are generally positive for increased APG utilization in the future. The Russian Government has proposed to gradually increase domestic natural gas prices for industrial users toward parity

[16] Gas with 250-300 grams of liquid per cubic meter, equivalent to 60% methane content

with export prices (on a netback basis) by 2011-2012. A substantial share of the LPG market is unregulated, and prices have increased substantially in recent years. In addition commercial arrangements with the aim of increasing GPP utilization and investment have recently been created e.g. JV's between Sibur, Rosneft and TNK-BP. But more is required.

3. Options for Commercializing APG

Currently available technology offers numerous options for commercializing APG or otherwise reducing gas flaring. The table below sets out the primary advantages and disadvantages of these options. The technical options fall into three categories: those that are purely local, such as flaring, reinjection, and local power generation, those that require gas to be gathered regionally, such as large-scale power generation, and those that require gas to be both gathered regionally and transported long distances to the west, such as gas processing and the sale of dry gas. While the first category requires little infrastructure, the other two can only be realized with some combination of existing and new infrastructure, including gas gathering pipelines, gas processing plants, and gas trunklines. Section 5 will discuss the hypothetical economics and comparative viability of these options.

	Advantages	**Disadvantages**
Flare	Low capital cost	Loss of economic value and scarce energy resource; pollution; potential health hazards
Reinject for future use	Preserves value	Not all formations suited for reinjection; capital cost for local processing and compression
Reinject for Enhanced Oil Recovery[17]	Provides revenue through increased oil production, may allow future recovery of some reinjected gas	Not all oil formations suitable for gas EOR; capital cost for local processing and compression
Local electricity generation for needs of oil field	Savings in purchased electricity or purchased diesel to generate power	Capital cost; field typically requires only 30% of power that its APG could generate and other local markets may be limited or nonexistent
Other local uses, including methanol production, steam production for EOR	Savings in previously purchased inputs, depending on field and process specifics	Capital cost; mismatches between gas needs and APG production
Regional electricity generation	Income from gas sales to electricity generators	Capital cost of gathering and processing infrastructure; low domestic electricity prices limit price offered for gas
Process APG to sell LPG (propane, butane) and dry gas	Income from LPG and gas sales	Capital cost of gathering infrastructure; limited processing plant capacity and access; possible limits on gas trunkline capacity
Process APG into petrochemical feedstocks and dry gas	Income from feedstock and gas sales	Capital cost of gathering infrastructure, processing, and fractionation; possible limits on gas trunkline capacity
Gas To Liquids (GTL): process gas to produce diesel	Income from liquids sales	Capital cost; scale of GTL plant requires investment in gathering infrastructure to bring gas from multiple fields

[17] Box 3 describes how natural gas is used for EOR

BOX 2

Using natural gas for Enhanced Oil recovery (EOR)

As early as the nineteenth century, gas injection was used to improve rates of recovery from oil fields. These early applications should be classified as pressure maintenance projects as they were originally designed to increase immediate productivity, but not ultimate recovery. More recently, gas injection has been used as a true Enhanced Oil Recovery (EOR) mechanism to increase ultimate recovery from oil fields.

In an EOR project, the injected fluid not only decreases the rate of pressure decline in the reservoir but also displaces oil and drives it toward the production wells. The success of an EOR project depends upon its **displacement efficiency** (how successfully the injected fluid displaces the oil) and **sweep efficiency** (the volume of the reservoir that the injected fluid enters). While gas may be less effective in both respects than water because it has a high viscosity contrast with oil, in reservoirs with high permeability and a combination of high dip and oil column height, the additional process of gravity segregation of the oil allows gas injection to produce high recovery factors. Gas injection may also be economically preferable because of the gas's ready availability.

Where reservoirs lack the vertical permeability or relief required for effective gravity segregation, operators may use a form of lateral drive similar to that used for water injection. This is called **dispersed gas injection**. In general, dispersed gas injection is likely to be more successful in reservoirs that are relatively thin and have little dip. Where reservoirs have higher vertical permeability (>200md) and enough vertical relief to allow the gas cap to displace the oil downwards, gas may be injected into the top of the formation or into the gas cap.

Reservoirs with strong natural water drives are unlikely to be good candidates for gas re-injection. In addition, since strong water drives often maintain reservoir pressure, there is always a danger that, by additionally injecting gas, the cap-rock or reservoir seal could be breached, leading to gas leakage. This risk is also present when gas is injected into depleted reservoirs. Extensive geomechanical modeling is required to minimize the risk of leakage in these situations.

4. How Have Other Countries Reduced Flaring

PFC Energy analyzed policies that are used to control gas flaring in Norway, the UK, Alberta (Canada), and the US. The best practices in these countries combine legal flaring limits, government agency reviews of new field developments, stringent monitoring and reporting requirements, and escalating penalties, including possible license termination. Countries that have high APG utilization rates also have commercial regimes that include unregulated gas prices and open access to adequate transportation infrastructure. In recent years, carbon dioxide taxes and other anti-global warming measures have further increased incentives for APG utilization in some countries. The common features of successful anti-flaring regimes include:

- Anti-flaring legislation accompanied by public reporting and monitoring
- Flexible approach that adapts to specific field circumstances
- Open and transparent access to pipelines and other infrastructure
- Independent pipeline regulatory body with effective enforcement capability and capacity for quick response, based on international best practices. This body should be independent of influence from current and future participants. It could be a completely separate organization or be part of government.

Appendix D reviews the regulatory regimes of several major producing countries. The key features of these systems include:

Norway

- Government directly regulates emissions through development and operational plans and environmental impact assessments
- Transparent process includes public consultation
- Open-access gas infrastructure jointly owned by multiple producers (replacing an earlier system in which Statoil control of the infrastructure blocked access for other producers)
- CO_2 tax provides additional incentives
- Flaring restrictions are credited with creating incentives to develop gas infrastructure, enhanced recovery, and new technology such as “closed flare systems”

UK

- Policies designed to maximize economic recovery of oil and gas reserves and reduce greenhouse gas emissions
- Department of Trade and Industry (DTI) controls all flaring and venting through Licensing and Consents unit
- DTI reviews all Field Development Plans, which must consider feasibility of APG utilization

- All but the smallest fields also require Environmental Impact Assessments
- Annual reporting required from all fields
- Flare Transfer Pilot Trading Scheme designed to further reduce gas flaring
- Third party access to upstream gas pipelines
- Unbundled midstream/downstream markets

Alberta, Canada

- Flaring regulated by province rather than the federal government
- Reduction of gas flaring is a priority of the Alberta Energy and Utilities Board (EUB)
- EUB requires operators to assess alternatives to flaring and venting
- Latest EUB directive requires operators to eliminate flaring even when this requires some subsidy
- Annual and public reporting requirements and periodic inspections
- Enforcement ladder system with escalating consequences for non-compliance
- Liberalized gas markets and open pipeline access with regulated tariffs
- Royalty waiver program designed to further reduce flaring

US

- Environmental Protection Agency regulates some APG components, but not methane itself
- Offshore operations regulated by federal Minerals Management Service (MMS), which permits only very limited gas flaring
- MMS requires monthly production statements, including flared gas volumes
- Bureau of Land Management also has flaring regulations and reporting requirements
- Individual states have rules and regulations governing flaring and venting
- Highly developed hydrocarbons markets and transportation infrastructure with open access

Some of the most innovative schemes to avoid gas flaring have evolved when companies or business units work together to create a superior solution for an entire system. Box 3 presents one such example from the UK's Magnus field.

Box 3

Utilizing Associated Gas: An Innovative Approach at the UK's Magnus Field[18]

In its early days, the Magnus field in the UK North Sea, exported its APG through a pipeline. As volumes declined with declining oil output, the field switched to using its APG for power generation. In 2000, reservoir studies indicated that Enhanced Oil Recovery (EOR) using natural gas could recover an additional 50 mmbbl from the maturing field, increasing the remaining reserves to be produced by a substantial 30 to 40%.

Since the field's own APG volumes were insufficient, achieving this EOR would require Magnus to buy gas from another field and invest in infrastructure to deliver it. PFC Energy estimates that paying full cost for the gas and infrastructure would have made the economics of the EOR project highly negative.

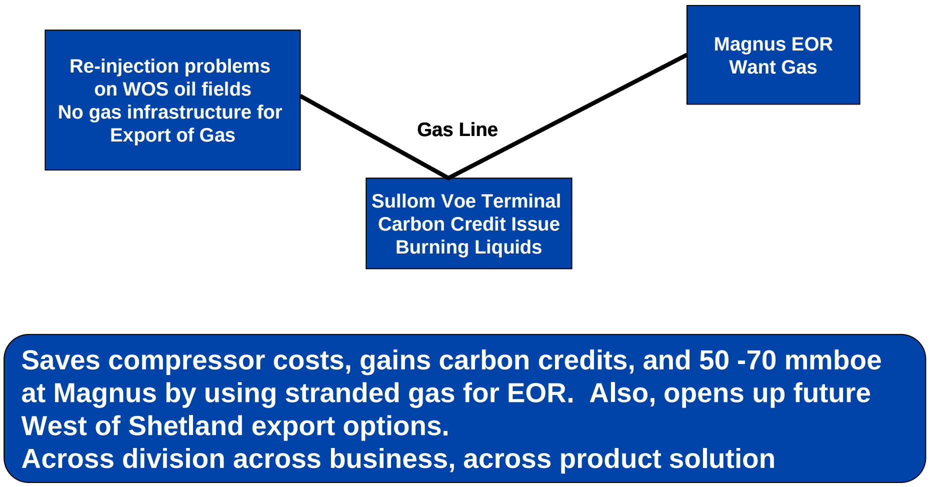
At the same time, two fields that were being developed with Floating Production units (FPSO) in deeper water West of Shetland (Fionaven and Schiehallion) sought a solution for their APG, which could not be flared under British regulations. As these fields were many miles from existing gas infrastructure, it was uneconomic to sell the gas to the market, and the obvious choice was to re-inject it into a nearby reservoir.

Meanwhile, the Sullom Voe terminal, Europe's largest, which processes oil from the Brent and other northern fields, was using fuel oil to generate its considerable power needs. Sullom Voe, which lies geographically between the West of Shetland fields and Magnus, was connected to Magnus via the pipeline that had once been used to export its APG.

None of these three issues seemed to have an economic solution in isolation. But equity owners with a stake in all three looked at the problems holistically and saw a creative approach. A large new pipeline was built from the West of Shetlands fields to Sullom Voe and then on to Magnus. This pipeline brought gas to be re-injected at Magnus to produce at least 50 mmbbl oil of additional oil. En route, Sullom Voe took some of the gas to fuel its power generation, earning emissions credits by substituting cleaner gas for fuel oil. In combination, the once-negative NPV of the three projects became positive.

[18] Analysis is based on public domain data and documents and PFC Energy's own assessment of the costs and economics.

An innovative approach to the UK's Magnus field: Integration with West of Shetland (WOS) gas results in flaring reduction without regulation

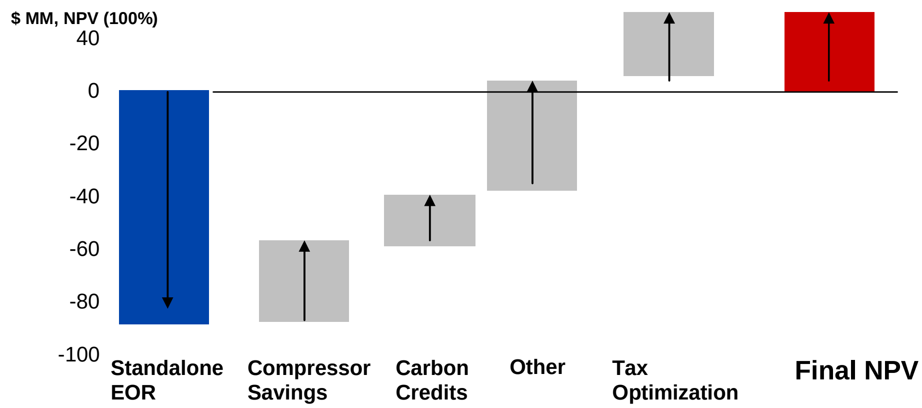


The diagram below shows how the economic value of the integrated plan is substantially more than the sum of its parts:

An innovative approach to the UK's Magnus field:

Economic Value Summary

Extra value elements



5. Economics of Commercializing APG and Comparison of Alternative Uses

PFC Energy analyzed the economics of five different options for utilizing APG, in each case assuming a new-build facility is required to take the APG:

1. Gas processing and sale of dry gas through the Gazprom pipeline system
2. Using gas to provide local power vs. purchasing power from the grid or generating power from diesel
3. Using gas in a regional power plant
4. Re-injecting gas for Enhanced Oil Recovery (EOR)
5. Using gas to supply a Gas-To-Liquids (GTL) plant

Each option assumes a new-build facility is required to use the APG. The complete analysis of these options is presented in Appendix C. The economics of APG gathering infrastructure is discussed in Appendix E. There could, of course, be other utilization options, but analyzing these was beyond the scope of this study.

Because the economics of the different options are driven by different parameters, with significant variation in the levels of investment, they cannot be compared on the basis of their IRRs. To allow comparisons between the options, as well as provide a key indicator of the economic margin available in each case, PFC Energy used the concept of an "equivalent netback APG price." This 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 APG to the facility would be prepared to pay a producer to purchase APG at the wellhead, while earning a 10% real return on his investment.

For example, for a new Gas Processing Plant, the annual pre-tax cash-flows would be:

GPP Investor cash-flow = Revenue - Capex - Opex - Equivalent netback APG price x APG gas volume
where Capex = Plant cost + connection cost, Opex = Plant operating cost

APG seller cash-flow = Equivalent netback APG price x APG gas volume
assuming no significant cost to deliver the gas at the field boundary

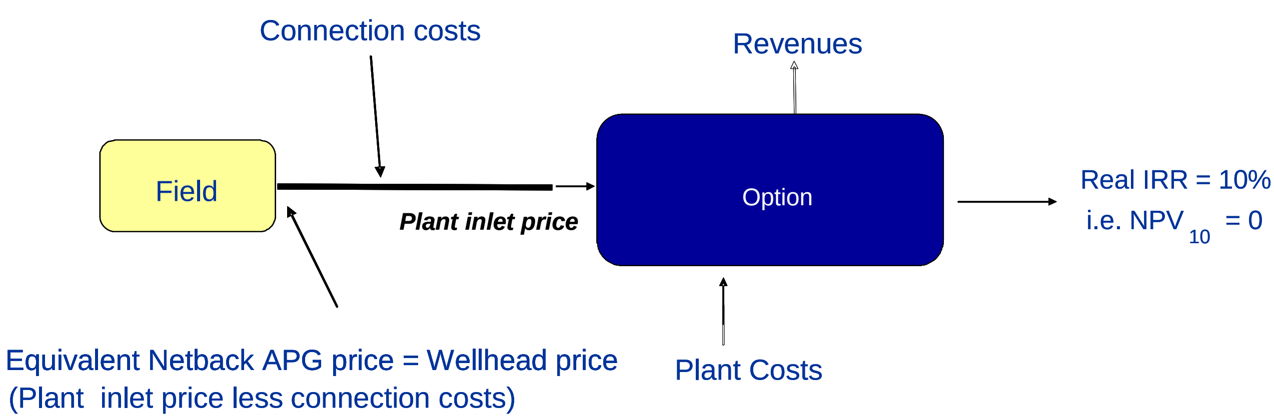
The overall pre-tax value of the project - the value to the 'system' - is the sum of the cumulative cash-flows of the GPP investor and the APG seller. Since the GPP investor is to earn a 10% real return, his cumulative cash-surplus at a 10% discount rate is zero. The overall "system" net present value at a 10% discount rate is therefore just the APG seller's cumulative cash-flow discounted at 10% which is the Equivalent netback APG price x Raw gas volume discounted at 10%.

Note that this investor is purely hypothetical. It could be an existing player such as Gazprom or a producing company, a new mid-stream company with activities like those of Duke Energy in the United States, a joint venture of stakeholders, or an independent investor. The analysis does not address who should invest in new equipment or infrastructure or how profits might be shared; it considers only the total economic value available to be captured by the entire system.

Figure 5.1

Equivalent Netback APG Price

§ **The maximum price that an owner of GPP/CCGT/Distributed power could pay the field owner after plant construction and connection costs and still make a 10% real IRR**



The Equivalent APG netback price represents the overall value to the system, and is equivalent to the system unit Net Present Value (NPV) at 10%. Multiplying the equivalent price by the discounted gas volume will provide the system NPV at 10%.[19]

[19] Discounted gas volume = [Bcm yr 1]/1.1 + {Bcm yr 2]/(1.1^2) + …. assuming a 10% discount factor.

Figure 5.2

Value of APG in the GPP System (including export infrastructure)

§ **Appears to be enough overall value in the system**

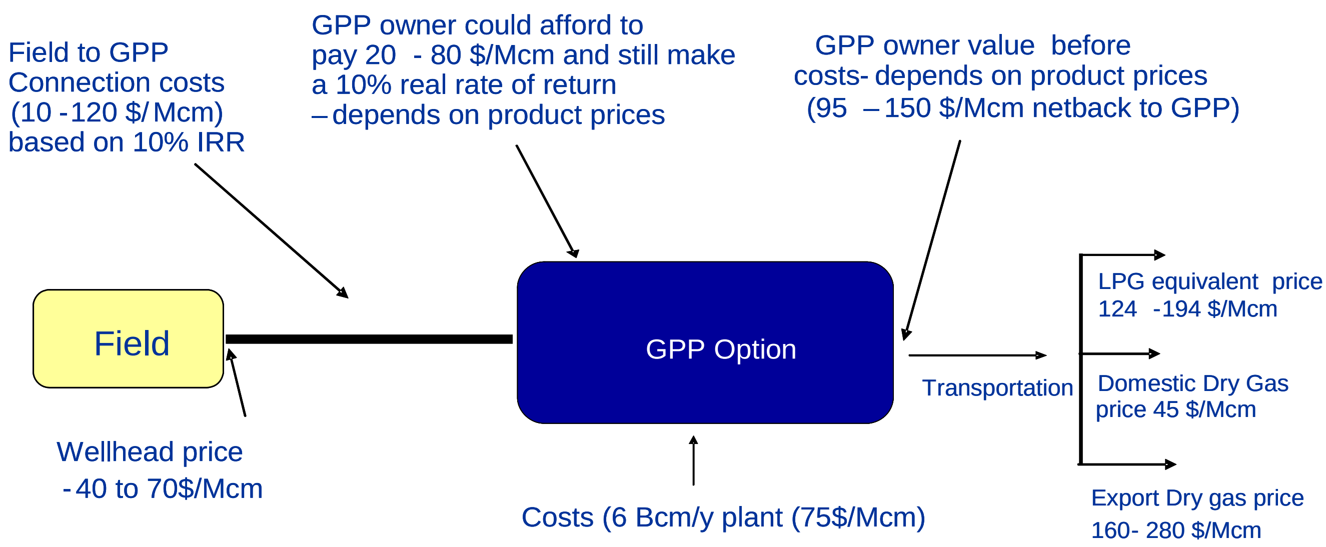
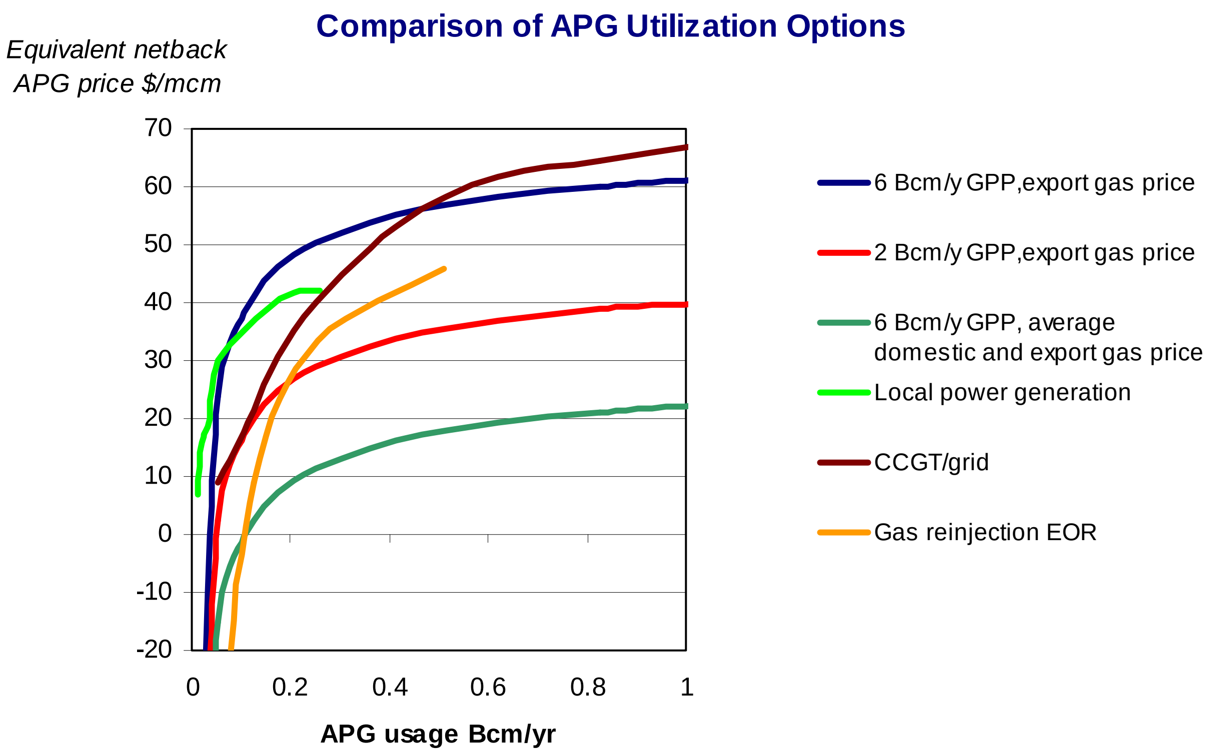


Chart 5.1 shows a comparison between the first four options. For simplicity, the chart does not include the GTL plant option, which was found to have clearly inferior economics[20]. The GPP option is considered at two different scales, 2 Bcm/y and 6 Bcm/y, on the assumption that dry gas is sold at average current export prices, net of the cost of transportation. A third GPP case considers a 6 Bcm/y plant selling dry gas at the average of export and current domestic prices, net of transportation costs, i.e. Gazprom's current mix of selling prices. Since Russian government policy is to allow domestic prices to move toward parity with export prices (net of transportation costs), these cases could be viewed as representing the long term economics (export prices) and current economics (average export and domestic prices) of the GPP option. All the GPP options assume that the plant is filled to capacity. The "local power generation" option assumes 30% own-usage with sale of the balance to the local grid. The "Central Station" option reflects a large Combined Cycle Gas Turbine (CCGT)

[20] Given current price and infrastructure constraints, GTL and other local conversion options may nonetheless be the optimal short-term commercialization solutions for individual producers.

power plant exporting to the grid. The Gas-injection EOR option assumes a 3-4%[21] increase in oil recovery.

Chart 5.1



The analysis led to the following conclusions:

- 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 GPP, provided inlet gas prices are increased to at least $35/Mcm.
- 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[22].

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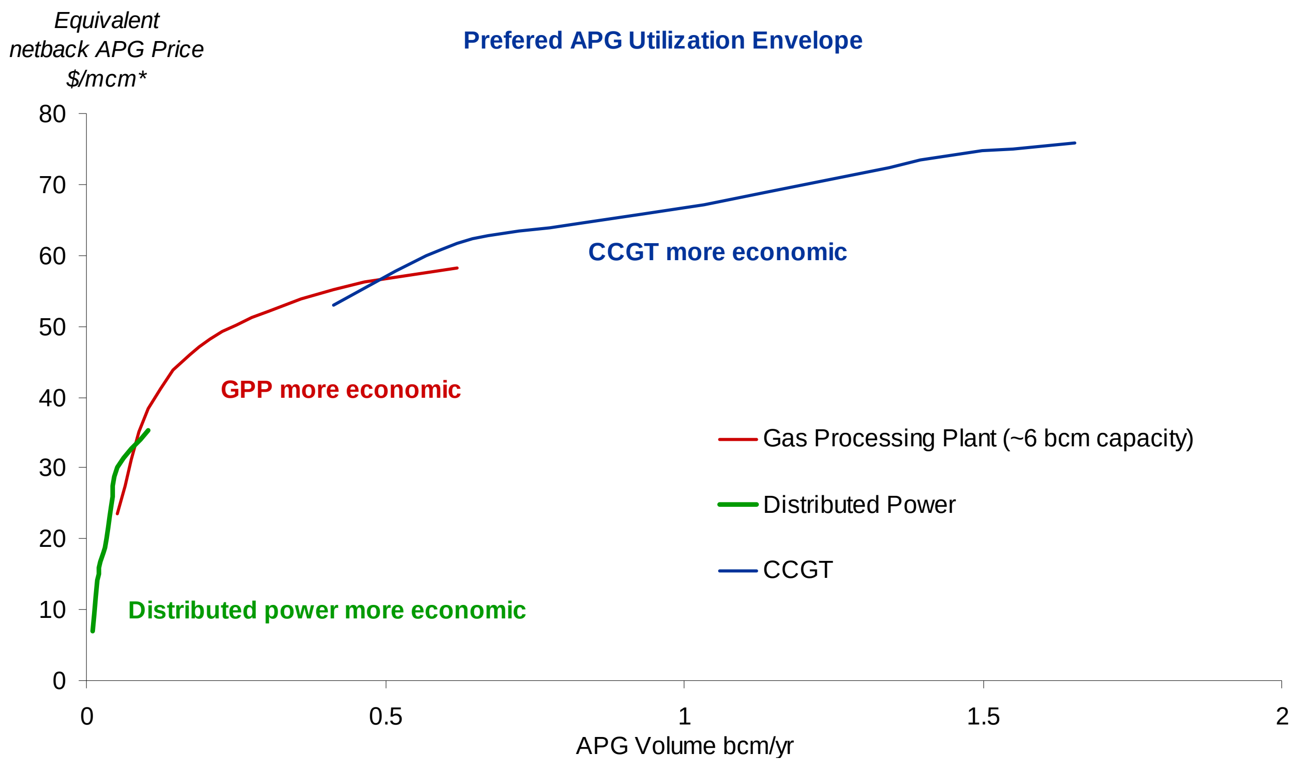
[21] Only a small percentage of fields have reservoir conditions suitable for gas-injection EOR. See Appendix C.

[22] This assumes that the power plant has access to the electricity grid and can sell at wholesale market prices

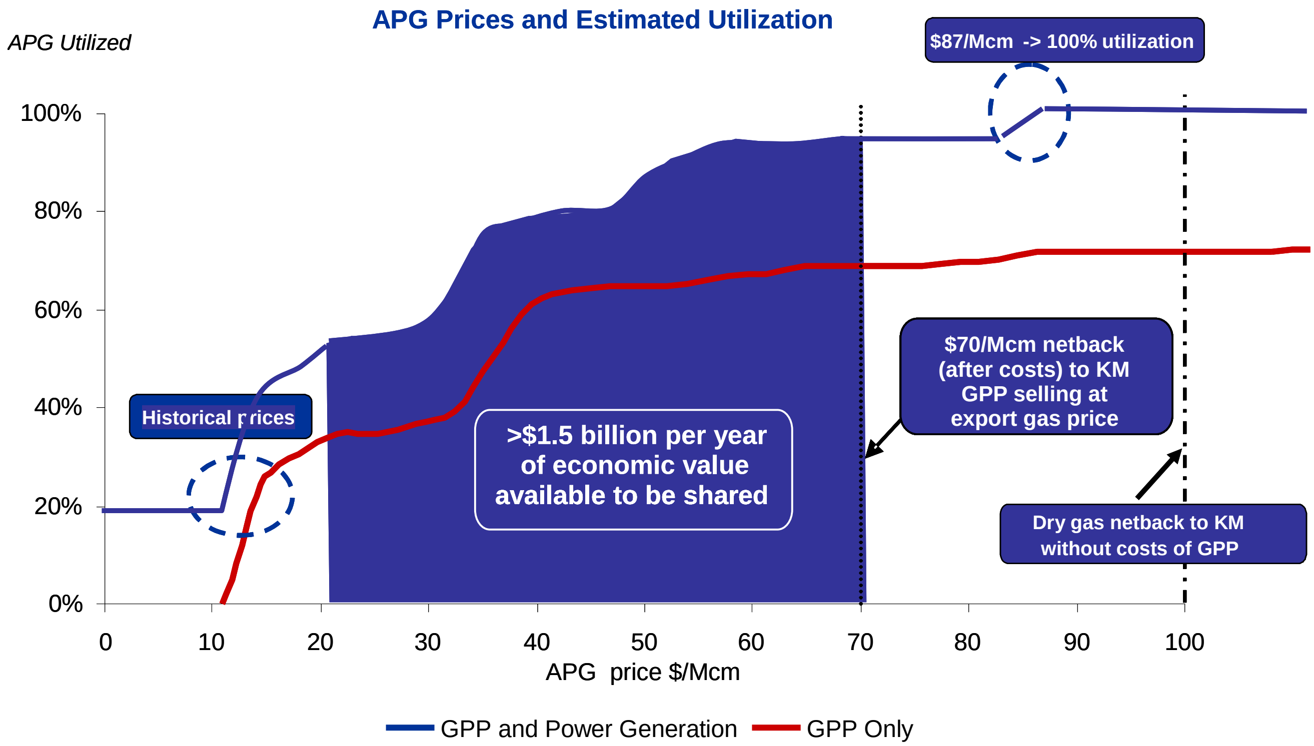
The chart shows the hypothetical economics of these alternatives, although specific technical and access issues could increase costs or even make certain options unachievable.

Chart 5.2



The economically optimal sections of the curves in Chart 5.1 are combined in Chart 5.2 to create a preferred options envelope that indicates the total value available to be shared by all participants in the system, or the potential value to Russia as a whole.

Chart 5.3



The cost of delivering APG to, for example, a GPP or power plant has been estimated as a function APG volume and distance to the GPP/power plant (see Appendix E). By combining this connection cost/volume relationship with the relationship between APG volume and equivalent netback APG price (chart 5.2), the incremental APG utilization as a function of incremental APG price paid to the gas supplier can be estimated. In this way, PFC Energy has estimated in Chart 5.3 how much of Russia's flared APG could be utilized as a function of equivalent netback APG price for a combination of the two most viable technologies: power generation and GPPs. As shown in Chart 5.3, at the historical regulated APG price of $9/Mcm, the GPP option was not economically viable for the producers. At an APG price equivalent to $20/Mcm, approximately 30% of flared gas volumes could potentially be recovered by GPP's alone, and an additional 20% could be recovered using power generation. At a $50/Mcm APG price, some 80% of flared gas volumes could be recovered using a combination of GPP and power generation. PFC Energy's analysis of the economics of gas processing and dry gas exports concluded that there is potentially enough value in the GPP and UGTS systems to justify APG prices of this magnitude at the GPP plant.

Although the analysis indicates that it would be theoretically possible to recover all the flared gas at a GPP or power plant inlet price of $87/Mcm, this is unlikely to be achieved in practice due to the specifics of individual fields.

This economic analysis assumes that there is adequate capacity in Gazprom's trunkline system to transport new dry gas extracted from APG. The Russian government has suggested that processed APG should be given priority access to the trunkline system in order to spur improved utilization. At present, as discussed in Section 2.5 of this report, the trunkline system does not have spare year-round capacity. This is expected to change as gas production begins to decline from Western Siberia's major producing fields (see Chart 2.5). Currently, Gazprom and independent producers have plans to slow the rate of gas production decline, and thus fill the pipelines, through incremental drilling programs at Urengoi and other fields in the region. Gazprom's declining production trend potentially creates an opportunity for both Gazprom and the producers who currently flare APG, since improved utilization of APG would provide a source of additional supplies for Gazprom to feed into its existing pipeline infrastructure. Rapid decline in gas production from existing fields could thus become an important catalyst for change within the government and Gazprom. Clearly, planning and coordination will be needed to determine the best uses for limited pipeline capacity and create an access regime that encourages APG utilization.

6. Recommendations to Reduce Gas Flaring

For Russia, the 18 Bcm/y[23] of dry gas that could be recovered through better utilization of APG, assuming appropriate infrastructure access, represents a substantial short-term gas resource and economic value that can be developed at relatively low risk and cost. It seems probable that APG could be a cheaper source of gas than Yamal in the short-to-medium term and, in the case where fields are shut in because of flaring legislation, priority access for APG over natural gas or gas condensate field production would clearly be economically preferred.

Understanding the hypothetical economics of APG utilization is only one piece of the puzzle of increasing Russia's APG utilization. To make higher APG utilization a reality will require investments to build GPPs, power plants, and pipelines. While the analysis indicates that these can provide rates of return on investment above cost of capital, this does not guarantee that they will be built. There may, for example, be more attractive alternative uses for capital for potential investors (i.e. capital allocation issues), or problems with the pricing and access regime that prevent investors from earning an economic return.

To ensure the viable options are implemented, the Russian state, which has an interest in conserving valuable resources and reducing environmental damage, should create penalties and incentives that encourage all the parties to create a better overall system. This system must include GPP inlet prices that are considerably higher than historically regulated levels, liberalized LPG prices, and open and transparent access to gas transportation infrastructure at regulated tariffs. Most vital will be sharing the value of the dry gas and LPG sold from GPPs. In the short term (five years or less), the fact that Russian domestic gas prices are considerably below world levels will limit the prices GPPs can pay for APG. This may drive gas producers toward solutions like GTL that are suboptimal for Russia as a whole, but may be the best option for individual field owners in the absence of infrastructure. The use of a blended price based on a combination of current export and domestic prices might make GPPs more economic and avoid this outcome.

PFC Energy makes the following recommendations for achieving better utilization of Russian APG:

- Include APG utilization requirements in all oil production licenses;
- Impose heavier penalties for gas flaring, including possible loss of operating licenses – assuming it is economic to utilize the gas;
- Set these penalties with regard for field size and location. One size does not fit all.
- Improve monitoring and enforcement and make it more transparent; clearly delineate between federal and

[23] 80% of 38 bcm/y of total estimated flared APG x 60% average methane content

regional responsibilities;

- Enforce third-party access to Gazprom pipelines;
- Establish an effective independent regulatory body to oversee pipeline access and tariffs;
- Continue to liberalize prices for APG, LPG, and natural gas;
- Provide Priority access for APG in gas transmission networks
- Create a Pipeline Infrastructure Working Group to identify unused gas transmission capacity.
- Take APG into account when planning future gas development and pipeline capacity.
- Use carbon financing: create a Designated National Authority to oversee Joint Implementation (JI) projects and define the rules for qualifying projects.

It is important to recognize that the order shown above does reflect the importance of one point over another. It is also important to acknowledge that no one element alone will provide an adequate solution to increasing APG utilization. A combination of rewards and penalties will be required.

7. Summary and Conclusions

- Russia flares an estimated total 38 Bcm/y of APG in total. This annual volume contains an estimated 22 Bcm of dry gas and 24 million tonnes of LPG.
- Significant volumes of APG are produced from small fields in thinly populated regions that are remote from major gas markets.
- There is substantial value to be captured in the system. With the appropriate infrastructure and a GPP inlet tariff of $20/Mcm Russia could recover 33% of currently flared volumes, for a potential annual economic benefit of $1.4 billion based on current Russian deregulated LPG prices and an average of domestic and export gas prices.
- Russia currently lacks the gas infrastructure of GPPs and pipelines needed to transport APG from the fields that currently flare, but should invest to build this infrastructure for economic and environmental reasons. Priority access should be given to APG.
- For small fields, local power generation appears to be the best use for the flared gas. For very large fields connected to the electricity grid, CCGT power generation appears the best option.
- At current prices, GTL and EOR may appear to be better economic options than GPPs for using APG, but Russia as a whole can gain more value by processing the gas and exporting it to Europe. This value would need to be shared with field owners to make utilization economic.
- The federal government has a key role in establishing a framework that provides incentives for all market players to participate in better utilization of APG.
- A greater understanding of Russia's reservoirs and produced solution gas profiles will facilitate the commercialization of flared APG.
- Even though it may be economic to capture much of the flared gas, investors may have better alternative uses for the capital. Other incentives and/or penalties may therefore be required.
- One size does not fit all. Large fields will be easily able to make economic investments in APG utilization infrastructure, but there will be others that cannot economically justify the investments to capture the APG that they are currently flaring.
- Connection costs for smaller fields (0.04<Bcm,/y) will be prohibitively high (>$60/Mcm). It is important that Russian field owners seek ways of increasing the economies of scale in delivering this gas to

market – e.g. by pooling their flows. Doubling these flows can reduce unit costs by around 40%[24].

[24] Increasing the flow from 0.02 – 0.04 Bcm/y.

APPENDICES – See Separate Companion Document

Item	Title
Appendix A	Estimation of Russian flared gas volumes
Appendix B	Western Siberian Pipelines: Current and Projected Utilization
Appendix C	Economic Analysis of Options for Utilizing Associated Gas
Appendix D	International Review of Policies Designed to Limit Gas Flaring
Appendix E	Economics of APG Gathering Pipelines
Appendix F	Associated Gas Utilization Plans of Russian Oil Producers
Appendix G	Gas Processing Plants and Sibur Holdings JSC

Note the Appendices are contained a separate but companion document