



Associated Petroleum Gas
Flaring Study for Russia,
Kazakhstan, Turkmenistan
and Azerbaijan

Final Report

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

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Executive Summary

The European Bank for Reconstruction and Development in cooperation with the Global Gas Flaring Reduction Partnership of the World Bank initiated in September 2011 a study on flaring of associated gas in Russia, Kazakhstan, Turkmenistan and Azerbaijan. The aim of the study was to review the flare situation and analyze appropriate technical solutions for the use of the associated petroleum gas, and to identify bankable projects in the four countries covered (“target countries”).

The study consisted of four parts: i) a review of the flare situation, policies and regulations and flare reduction actions in the target countries ii) identification of flare sites and dialogue with companies on possible assistance in the analysis of flare reduction efforts iii) technical and economic analysis of specific investment cases iv) dissemination of project results.

The flare situation

Flaring of associated gas is a major resource waste and causes large emissions of greenhouse gases and air pollutants. Although the total volume of flaring is uncertain, the target countries combined currently flare more than 20 billion cubic meters per year, of which almost 85% by Russia. Russia, unlike the other countries in the study, has not managed to reduce the flaring over the past 5-6 years; flaring remains at 24-25% of total associated gas production. A flaring rate of 5% (gas utilization rate 95%), indicative of elimination of routine flaring, is commonly set as a policy target for flaring, also in the four countries of this study.

According to official national data, Kazakhstan has over the past 4-5 years made substantial progress towards a 5% flare rate. Flaring in Azerbaijan is also close to that level, having oscillated around 6% since 2008. Azerbaijan has made large investments in gas utilization in parallel with the expansion of oil production. This contrasts with the developments in Russia where investments in associated gas utilization typically lag behind investments in new oil production capacity. As a result, flaring has increased markedly from new production regions in Eastern Siberia, counterweighting the progress made in flare reduction in mature oil regions such as Khanty Mansyisk.

Companies operating in Turkmenistan have made significant investments in flare reduction, but no information is available on the overall impacts on flaring for the country.

Flare sites and flare reduction efforts

In order to select flare reduction cases for further scrutiny a screening process was initiated. Some 400 flare sites were identified using satellite images from the National Oceanic and Atmospheric Administration (NOAA) and “on the ground data” from other data sources. Some 80% of the identified sites had relatively modest flare volumes (each less than 100 million cubic meters annually), while less than 10 sites (2.5%) flared more than one billion cubic meters. A review of ongoing flare reduction efforts

indicate that many of the large flare sites have reduction solutions underway implying that small and medium size flares site become even more important. Improving the economic attractiveness of gas utilization investments from such sites should be the focus of future flare reduction policies and action. It will require new ways of cooperation between political authorities and those companies taking on the commercial risks of investments.

There will continue to be large flare sites, primarily connected to new production sites in Russia, but flaring from these sites will typically be temporary as gas utilization solutions lag behind in field development and commissioning. Eliminating this time lag is also important in order to bring flaring to a minimum.

Gas utilization options and investment cases

A number of technology components (suitable for gas gathering, treatment and processing and transport of products) can be used and alternative value chains can be established to avoid flaring. A comprehensive review of the costs and benefit of gas utilization options, reflecting local and national circumstances, have been reviewed as part of this study. It shows that they are highly case specific with differences in costs of bringing gas to markets, and with differences in the quality of gas being supplied and the local willingness to pay for the gas. Detailed results from the investment cases of this study cannot (for commercial sensitivity reasons) be presented in this report, but some general conclusions can be drawn:

- Many flare reduction projects are economic (internal rate of return above seven percent) but are still not being implemented. Since flare reduction investments on an everyday basis must compete with oil production expansion for financial and human resources they are often not prioritized even if awareness of the flaring problem has improved. One approach to spur flare reduction investments with proven results (as shown in this study) is to invite external parties to purchase the associated gas and to take on the commercial risks and financing of gas utilization projects.
- Economies-of-scale is a key driver for the financial viability of flare reduction investments. Typically small and medium size production sites cannot offer stable and large enough quantities of gas. Therefore integrated solutions where gas from multiple sites are gathered and processed in centralized facilities can improve considerably the economic return on investments. In one specific case studied in Kazakhstan, supplies from three fields controlled by one company gave a twelve percent rate of return on the investment. This was improved to eighteen percent when four more fields were added.
- Several investment cases with gas-to-liquids technologies were studied. Technology costs have come down substantially but the financial viability of such investments is often still marginal at “normal market prices”. In certain cases local prices for liquids are high for logistic or other reasons hence improving the economic returns on gas-to-liquids as a gas utilization option. Manufacturers of such technologies are increasingly active in pursuing business opportunities in Russia, e.g for small and medium scale application in remote areas. No full-scale investments have been implemented yet, but a few pilot schemes are underway.

Dissemination of project results

The last part of this study included workshops in Moscow, Astana and Baku attended by (in total 200) experts from oil companies, national authorities, technology providers and research institutions. Project results were presented and investment barriers and regulatory and commercial challenges were discussed. The authors of this report consider the following to be the main issues addressed at the workshops:

- There is a gradual shift in the composition of flare sites with a larger part being small and medium size, often with difficult access to markets. Associated gas utilization investments from these sites are often uneconomic. Regulatory approaches and commercial solutions must in a better way than until now adapt to this reality.
- Authorities in the target countries have typically set ambitious flare reduction targets, while regulatory approaches and enforcement mechanisms often have been adequate. Given the great diversity in the economics of flare reduction investment more flexibility in regulation is needed. A regulatory approach based on dialogue and cooperation with companies, but still with credible and predictable enforcement mechanisms intact, can contribute considerably to the cost-effectiveness of flare reduction. Further, regulators have an important role to play in facilitating new and innovative commercial approaches to flare reduction investments (see below).
- Economic unattractive standalone investments, pursued by one oil producer, may become viable through a productive partnership involving companies with different expertise and willingness to take on risks. Some legal and regulatory reforms have recently been implemented in Russia and Kazakhstan in support of “clustering” of projects with supplies of associated gas from multiple fields, but there are still few signs of active engagement from authorities in clustering and partnership arrangements for flare reduction investments.
- With the continued technology advances and cost reductions for small-scale gas-to-liquids technologies this is increasingly becoming an interesting option in the case of stranded associated gas in remote small and medium-sized fields. Technology providers, finance institutions and other commercial actors have shown interest in taking part in such investments. Again, political authorities, regulators and institutions such as the European Bank for Reconstruction and Development and the World Bank can play a role in bringing together various industrial partners so as to find viable investment solutions with acceptable allocation of risks and rewards among commercial partners.
- Carbon market may eventually resurrect from its current low and become additional economic stimulus to flaring reduction investments. A number of projects have already been developed in the target countries under Joint-Implementation and Clean Development Mechanism (CDM). Flare reduction projects are well suited for these mechanisms since they can offer relatively large emission reductions at low costs. In addition Kazakhstan is implementing its Emissions Trading Scheme. Russia is at an early stage of considering the establishment of a domestic carbon pricing scheme.

New investments in associated gas utilization

This study has shown that many financially viable associated gas utilization projects are not pursued due to lack of priority given by oil companies and/or lack of adequate regulatory pressures. This situation can be improved, but not necessarily by more prescriptive regulations. New commercial players should be encouraged to enter this field. Innovative commercial approaches, helped by technological progress, can also improve the financial returns on projects which at the outset are seen as uneconomic. A critical factor for this to be realized is active and flexible participation from political and regulatory authorities.

Considerable investments are required in order to reach the 95% gas utilization target, especially in Russia. Estimates made as part of this study indicate that Russia would need to invest USD 8 billion to reach the 95% target for existing production sites and an additional USD 16 billion to achieve 95% associated gas utilization from new production. This is yet another indication of the need for more institutions to engage in flare reduction efforts. The obvious and considerable resource conservation and environmental benefits should be for the European Bank for Reconstruction and Development and the World Bank Group an additional impetus for providing support and co-financing.

1. Introduction

1.1 Purpose, focus and analytical approach

This report summarizes the findings of the “Associated Petroleum Gas Flaring Study for Russia, Kazakhstan, Turkmenistan and Azerbaijan” (the Study) which was initiated by the European Bank for Reconstruction and Development (EBRD) and co-managed by EBRD and the Global Gas Flaring Reduction Partnership (GGFR). The aim of the Study has been to review and analyze appropriate technical solutions for the use of the associated petroleum gas (APG) and to identify bankable projects in the four countries covered (“target countries”).

EBRD considers expanding its financial engagements in associated petroleum gas (APG) projects through the Sustainable Energy Initiative (SEI). SEI was launched in 2006 as a specific contribution to address the climate change challenge, with a particular focus on energy efficiency. Until the end of 2012 SEI had invested EUR 11 billion, of which 10% were allocated to oil and gas sector projects and only a small share to APG utilization. This Study concludes that investments in productive use of APG could be an important target area for SEI financing, for two reasons:

- (i) **The significance of capital requirements for APG investments.** Bringing the current flaring down to the level set by political authorities in the four target countries (about 95% APG utilization rate) is estimated to require some USD 7.5 billion in capital expenditures. In addition, avoiding flaring from new production sites until 2020 might require some additional USD 15.5 billion in investment funds.
- (ii) **A good match with SEI objectives.** While APG investment by international oil companies typically would be financed outside the multilateral development banks, there are projects that are hindered or delayed by lack of financing. Small and medium size sites represent a growing share of remaining flare sites, and SEI co-financing and other support (e.g. project facilitation where various actors are involved) could accelerate flare reduction investments. In addition flaring of APG is a significant contributor to greenhouse gas emissions in the target countries and as climate mitigation actions they are in many instances “low hanging fruits”.

In order to explore appropriate gas utilization options and identify bankable projects in the four target countries the Study was carried out in four phases:

- **Phase 1:** A review of the flare situation, flare reduction efforts and relevant regulations and policies in each of the four countries covered.
- **Phase 2:** Identification of flare sites and dialogue with companies on possible assistance in the review and analysis of APG investment cases.
- **Phase 3:** Technical and economic analysis of specific investment cases.
- **Phase 4:** Dissemination of project results.

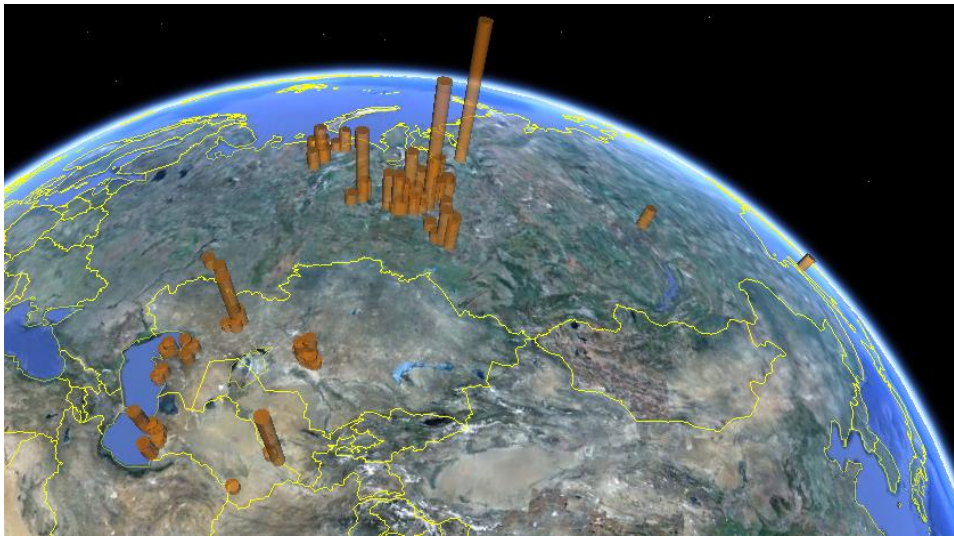
Main results from **Phase 1** are summarized in **Chapter 2** with separate presentations made for each of the four target countries. The characteristics of flaring differ substantially between the countries as does

regulations and policies, but they have some challenges in common. All countries have considerable unexploited reserves of oil and gas and they are building new supply chains to markets. Hence associated gas production will increase, while new gas infrastructure opens the way for better market access. Still, it should be noted that much of new oil production originate from remote locations bringing new challenges in terms of APG utilization investments.

Identification of flare sites in **Phase 2** has been a data intensive exercise where some 400 flare sites initially were identified followed by a further screening process leading to some 100 flare sites being selected for further scrutiny. For this work two sets of data sources have been used in combination:

- a. **Satellite images:** the main source of information is the nighttime light satellite images provided by National Oceanic and Atmospheric Administration (NOAA), which have been used in combination with a Geographic Information System (GIS) software and Google Earth to identify the flares and estimate the volume of gas combusted.
- b. **“On the ground data”.** It describes relevant field specific characteristics required in order to estimate flaring volumes. The most important source is a database compiled by the consultancy IHS which includes, amongst other, the field geographical location and the produced gas characteristics.

Figure 1: Overview of “100 sites”



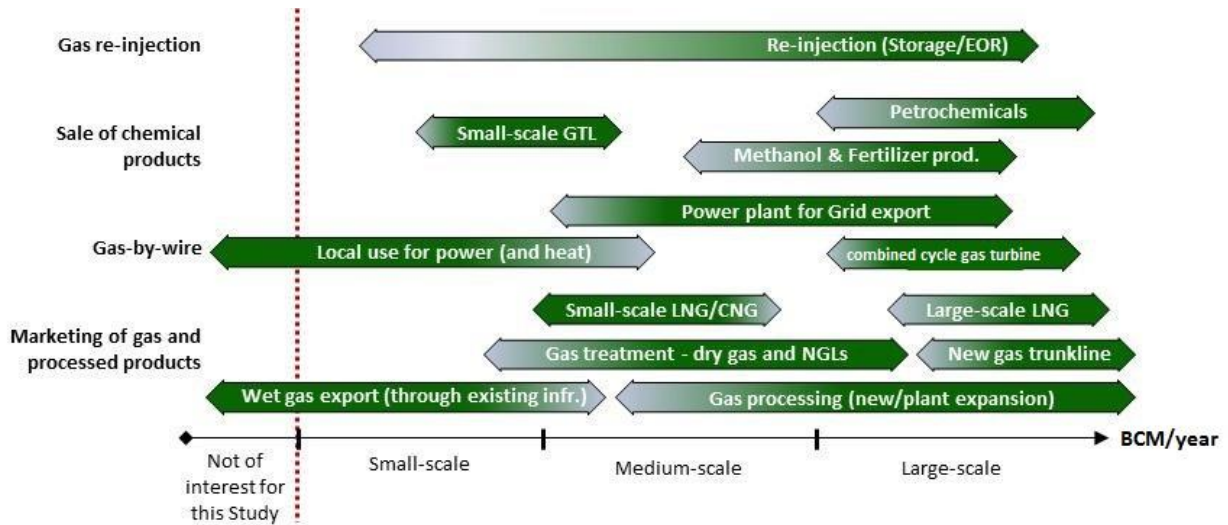
Source: IHS, Google Earth and Carbon Limits

By combining the satellite images from NOAA and the geographic information from IHS, the locations of flares were determined. When required, the presence of the flares was confirmed with Google Earth. The next step was to estimate flaring volumes per site. To do so, the sum of the light intensity (SOL) over every flaring site was calculated and a factor applied to convert the SOL into a flaring volume. The information compiled and analyzed as part of the site selection process was also used in the country review work and summaries are presented in **Chapter 2**¹. In the site selection process for the Study it was considered important to have a reasonable distribution with respect to applicable technologies and

¹ Confidentiality clauses in some of the primary data sources used for the Study has restricted the level of detail that can be presented in this report.

gas utilization options. Selecting a variety of gas utilization options created specific challenges since applicable technologies cannot easily be determined in an early and high-level selection process. Still, there is typically a correlation between the technology/gas utilization option and the total volume of gas to be recovered, as illustrated in *Figure 2*. The selection, therefore, sought to have a balanced distribution of sites in terms of flare volumes.

Figure 2: Attractiveness of conceptual gas utilization options vis-à-vis recoverable gas volumes



Source: Carbon Limits

The further identification of investment cases and detailed technical and economic analyses of these cases (**Phase 3**) had as its analytical basis a conceptual screening report prepared in order to describe key characteristics, including economic attractiveness, of gas utilization options suitable in the four target countries. Key conclusions from the conceptual screening report are summarized in **Chapter 3**. This chapter also analyses the economic attractiveness of different technology choices and gas utilization options with emphasis on how this is sensitive to site specific factors and variables such as: i) gas volumes and qualities ii) distance to markets and transportation infrastructure iii) netback values of gas, LPG, condensate, diesel and electricity. This analysis is based on the case studies, however again with the restriction that commercially and company specific information cannot be published.

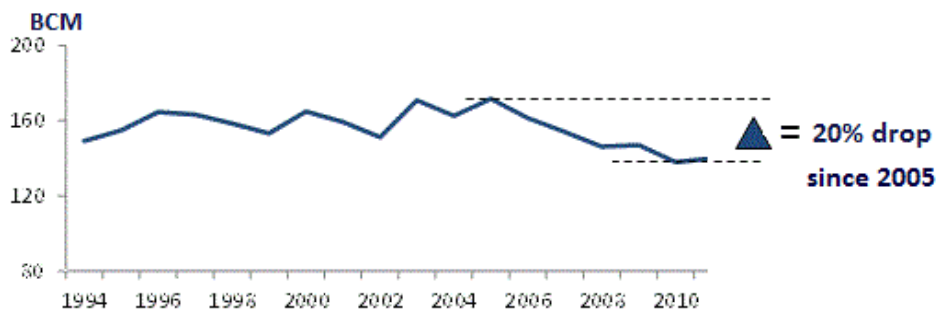
Results from the Study show that the scope and character of the flare reduction challenges are changing, with a larger part of flaring being from small and medium size flare sites often far from existing gas infrastructure and markets. This represents specific challenges for design and implementation of policies and regulations. Policies and regulations should recognize the great diversity in costs of flare reduction efforts and actively promote application of new technological advances and innovative commercial approaches, with sharing of risks. New opportunities for economically viable investments in small and medium scale gas utilization cases are briefly addressed in **Chapter 4**.

1.2 Overview of flaring levels and trends

Associated Petroleum Gas (APG) flaring takes place when gas produced in association with crude oil is not used for productive/energy purposes, due to lack of market outlets or for safety reasons. Estimates calculated from satellite images of flares (NOAA data, reported by GGFR) suggest that global gas flaring in 2012 was 144 billion cubic meters (BCM). This represents a massive resource waste and a considerable environmental problem, representing some 400 million tons in CO₂ emissions and being at the level of one third of EUs gas consumption. In addition gas flares emit methane and black carbon, which as so-called short lived climate pollutants are particularly powerful as precursors of climate change.

Policies and regulations to tackle the problem have been stepped up considerably over the past 10 to 15 years and oil and gas companies have taken active steps to plan and implement flare reduction measures. On a global scale this resulted in a decline in flaring volumes from 2005 to 2010 of about 20%.

Figure 3: Flare volume and flare intensities



Source: GGFR/NOAA

Estimates from satellite data, however, indicate a rebound in flaring from after 2010

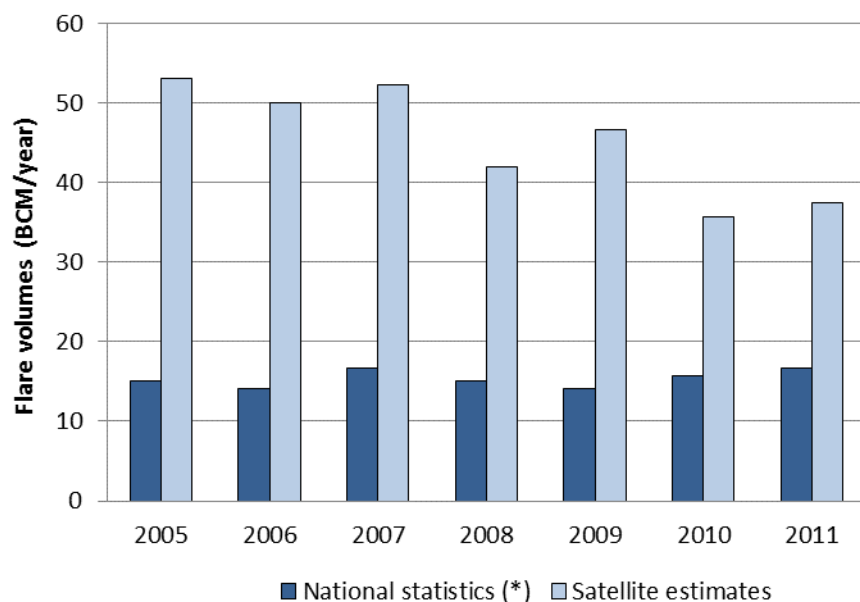
Russian remains the largest flaring country in the world, both based on national statistics and satellite estimates. However, the two sources show major discrepancies in flare levels and in trends from 2005 and onwards, see *Figure 4*.

Detailed empirical examinations under this Study suggest that three causes contribute to the discrepancies:

- **Uncertainties in converting “sums of light” from satellite images to flare volumes.** Analyses done as part of this Study suggest that the global conversion factors used by NOAA, in the case of Russia and Kazakhstan, overstate flare volumes. The fact that satellite images are not continuous measurements but “snapshots” represents a possible source of error, in particular for the northern hemisphere in presence of seasonal variations in flaring.
- **Satellite images include more than flaring of associated gas.** Although considerable efforts exclude light that are not from oil production flaring sites, such sources may in some cases be included. Most importantly flaring of non-associated gas from gas processing plants or refineries are often included in the satellite data but may be excluded from the national statistical sources used for this Study.

- Uncertainties in national statistics.** National statistics are based on reports from oil and gas companies which not always measure gas that goes to flares, but rather makes estimates of associated gas production and flaring, based on gas-to-oil ratios and other (indirect) parameters. Given that flaring is subject to regulations and penalties, there may also be a tendency that flaring is systematically underreported.

Figure 4: Flare volumes in Russia, national statistics and satellite estimates, BCM/year



(*) Central Dispatch Office of the Russian Fuel and Energy Industry (CDU TEK).

Source: Satellite estimates are from NOAA/GGFR

Data for Kazakhstan show similar discrepancies between satellite estimates and national statistics; with the latter being at less than half the level of satellite estimates, and with a clearer downward trend in national statistics but not in satellite estimates (see **Section 2.2**).

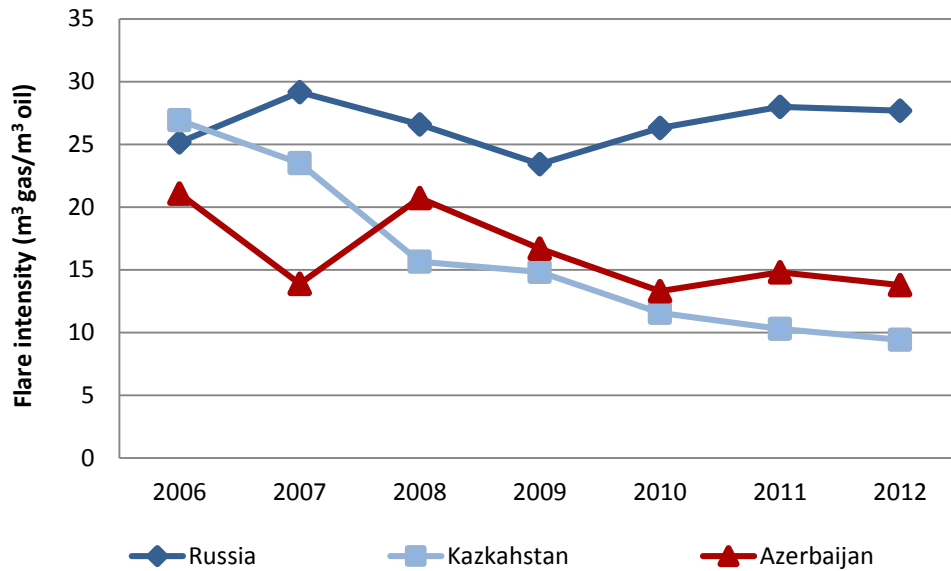
Table 1: Flaring of associated gas in target countries based on official statistics, 2006-2012, Billion cubic meters (BCM)

Country	2006	2007	2008	2009	2010	2011	2012
Russia	14.1	16.7	15.1	13.5	15.5	16.7	17.1
Kazakhstan	3.1	2.7	1.8	1.7	1.4	1.2	1.0
Turkmenistan	0.9	0.9	1.2	1.1	1.0	NA	NA
Azerbaijan	0.8	0.7	1.1	1.0	0.8	0.8	0.7
Total – Target Countries	18.9	21.0	19.2	17.0	18.7	NA	NA

Data sources/estimates. Russia: Central Dispatch Office of the Russian Fuel and Energy Industry. Kazakhstan: Ministry of Oil and Gas. Turkmenistan: NOAA/GGFR and Carbon Limits estimates based on IHS data sources. Azerbaijan: BP in Azerbaijan sustainability reports (includes flaring from Azeri-Chirag- Deepwater Gunashli and the Sangachal terminal). Data for Azerbaijan include venting of associated gas as reported by SOCAR (see Figure 16). NA = Not Available

Flaring of associated gas in the four target countries, based on national statistics², for the four target countries, is shown in *Table 1*. Russia has by far the largest flaring level and has unlike Kazakhstan not managed to reduce the level over the past seven years.

Figure 5: Flare intensities in Russia, Kazakhstan and Azerbaijan, in m³ gas per m³ oil



Source: Flare data see *Table 1*, oil production BP Statistical Review

Considering flaring per unit of crude oil production (flare intensities) Kazakhstan and Azerbaijan have shown progress since 2006 and had a flare intensity level in 2012 less than half the level in Russia. Russia and Kazakhstan were at about the same level in 2006 but Russia has not managed to reduce the flaring, due to major new flaring sites appearing from new production sites in Eastern Siberia (see **Section 2.1**).

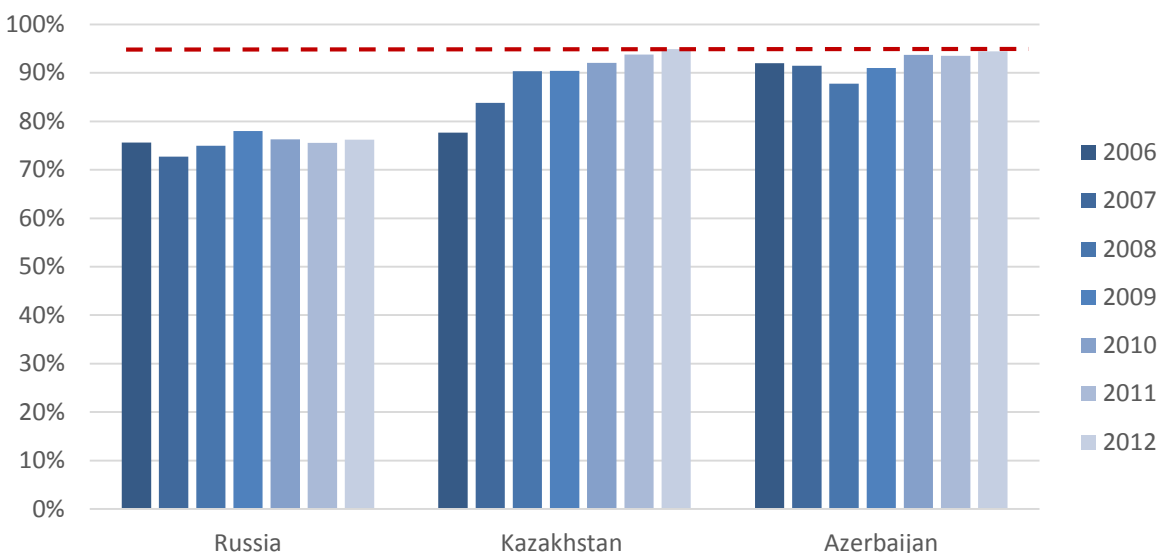
The relative importance of flaring can also be displayed as the share of total APG production being flared (APG utilization rate). Commonly a target is set for 95% of the APG being used for energy purposes or being re-injected. All new license agreements in Russia have a 95% utilization obligation and such a threshold is often referred to as a target in political statements.

According to national statistics Azerbaijan and Kazakhstan are closest to this target, while Russia lacks almost 20 percentage points short of the, which in the case of Russia initially was announced in 2007, for achievement by end of 2012. As noted above, there may be a certain underreporting of flaring in the national statistics which implies that both Russia and Kazakhstan are somewhat further away from the 95% target relative to what is shown in *Figure 1.6*. In Turkmenistan the situation is less clear since no national statistics of APG production and flaring are available. Satellite estimates suggest that flaring of APG was about 1 BCM in 2010. With crude oil production at 0.2 million barrels per day APG utilization in Turkmenistan would have been well below 50%. As presented **Section 2.3** some major APG investments

² There does not exist national statistics from flaring in Turkmenistan, estimates are therefore based on NOAA data.

have been launched in Turkmenistan over the past few year, but it is yet unknown to what degree these have increased the utilization rate.

Figure 6: APG utilization rates in the four target countries, 2006-2012



Source: Same as for Table 1

1.3 Investments in APG utilization by 2020

Considerable investment funds are required for Russia to reach the 95% utilization target from existing production sites; approximately USD 8 billion according to estimates done in this Study³. Judged from the national statistics costs for reduction of current flaring in Kazakhstan and Azerbaijan are modest.

All the target countries have large programs for exploration and development of new oil fields, see Table 2 and investments for avoiding flaring from these fields will be considerable. This Study has estimated such investments to amount to about USD 16 billion to 2020 in the case of Russia.

³ The estimates of investments required to establish infrastructure to meet APG utilization targets for existing and new production sites by 2020 are uncertain and qualitative by nature. Estimates are based on a large number of assumptions, including the development of Russian oil production, the share of total APG production in 2020 from new developments, the effects of projects under implementation at existing flare sites, the “remoteness” of existing and new APG production sites and new infrastructure (GPPs and GTPPs), the required installed capacity relative to actual APG recovery, the cost synergies associated with designing integrated APG solutions for new developments, the size distribution of APG volumes to be recovered at existing and new production sites, the optimal technology mix to utilize gas from existing and new production sites and the unit cost of new infrastructure to utilize APG using alternative technologies at different scales. The estimates presented in this report are made for an assumed mix of technological solutions that take into account locations of APG volumes in 2020 and the size distribution of these APG sources. These technologies would yield products with different market values (ranging from unprocessed APG delivered to GPPs to diesel produced using GTL technologies). In general, capital intensive utilization options generally yield products that would attract higher values in the market. The market value of the products resulting from the estimated capital investments have not been estimated in this study.

Table 2: Oil production in target countries, 2010-2020, million barrels per day

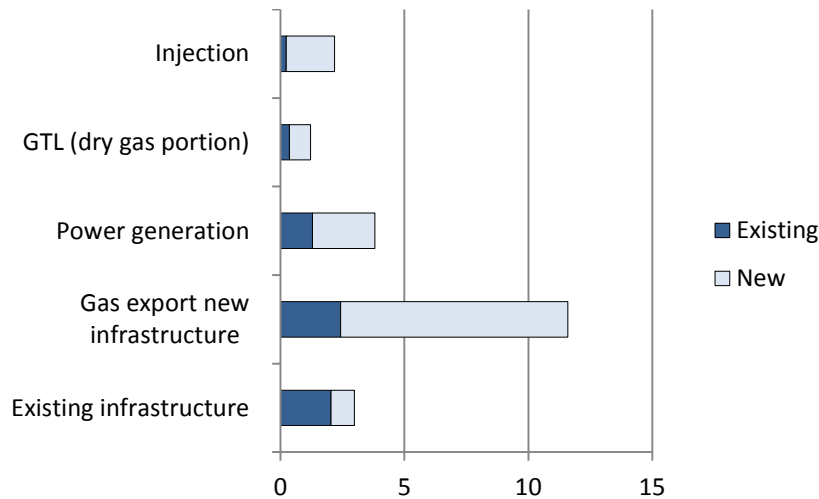
Country	Actual			Forecasts	
	2010	2011	2012	2015	2020
Russia (*)	10.1	10.2	10.3	10.5	10.8
Kazakhstan (*)	1.6	1.6	1.6	2.1	2.5
Turkmenistan (**)	0.2	0.2	0.2	0.2	0.3
Azerbaijan (**)	1.0	0.9	0.9	0.9	0.9
Total – Target Countries	12.9	12.9	13.0	14.2	15.4

(*) EIA World Energy Outlook, 2013 (**) Carbon Limits estimates based on different sources

In addition to Russia, Kazakhstan expects a marked increase in production, but a large part of this will be from the Kashagan field where development started in 2001 and production started in 2013. In this case, therefore, APG utilization investments have already been made.

A specification of investment expenditures by APG utilization option is given in Figure 7. The estimates are based on typical costs for different APG supply options shown in more detail in Chapter 3. Such estimates are highly uncertain, partly because solutions and costs for APG investments are site specific and also because of the uncertainty that exist around current flare levels and where new APG production will appear over the next 7-10 years period. Still, the numbers indicate that considerable investment funds will be needed for reduction of flaring from exiting production sites and in order to avoid flaring from new fields.

Figure 7: Capital expenditures for APG utilization till 2020 in Russia, billion USD



Source: Carbon Limits analysis

2. Review of flaring situation in target countries

2.1 Russia

2.1.1 Flare levels and trends

It is generally accepted that Russia is the largest contributor to global gas flaring. However, there is significant uncertainty regarding actual volumes, as data even vary between Russian official sources. For example, the Central Dispatch Office of the Russian Fuel and Energy Industry historically has reported a larger volume of APG flared than the Federal Service for State Statistics. Moreover, President Vladimir Putin in his 2007 State of the Union address quoted an annual APG flaring figure (20 BCM) that was some 20% greater than the figure of the Central Dispatch Office. Reasons for such discrepancies likely include differences in estimation methodologies employed by the different sources.

Table 3: APG production and flaring data from official Russian sources, BCM

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
APG production	48.5	54.9	57.6	57.9	61.2	60.3	61.4	65.3	68.4	71.9
Flaring of APG	11.1	14.7	15.0	14.1	16.7	15.1	13.5	15.5	16.8	17.1
Utilization rate (%)	77.2	73.3	74.0	75.6	72.6	75.2	78.0	76.3	75.5	76.2

Source: Central Dispatch Office of the Russian Fuel and Energy Industry

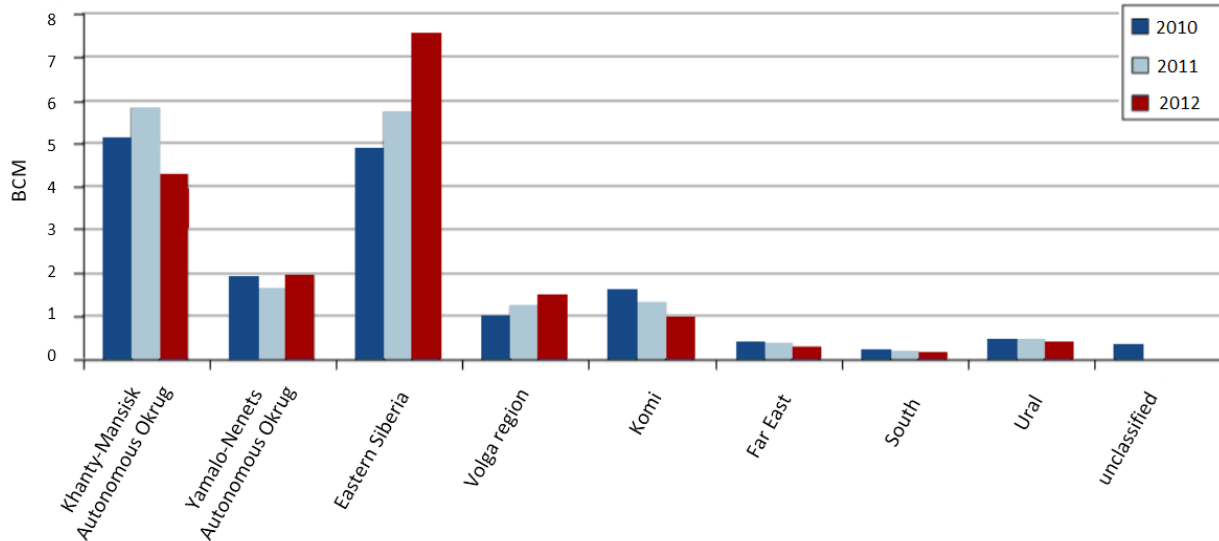
As noted in **Chapter 1**, most Russian sources report much lower flare volumes than does the GGFR, which uses estimates from satellite data provided by the National Oceanic and Atmospheric Administration (NOAA). Part of the difference can be attributed to inclusion of non-associated gas flaring in the satellite data, but most probably the major part is caused by a combination of overestimates from satellite-based data sources and underreporting in national statistics.

The largest volumes of APG historically have been produced in Western Siberia, which accounts for the majority of past and current oil production in Russia. However, APG production has increased in other regions due to oil field developments, particularly in Eastern Siberia. Limited flaring occurs in the other traditional oil producing regions, most notably in Orenburg, but flaring levels there are decreasing along with oil production.

The majority of the APG produced in Western Siberia originates from oil fields in the Khanty-Mansisk Autonomous Okrug, which contains more than 220 active fields and produces about 57% of Russian oil. Almost 40% of the APG flaring in this region is estimated to occur at only 3 fields: Priobskoye, Samotlor and Krasnoleningskoye, which are among the largest in Russia.

Most flaring in Western Siberia is located within an area of less than 500 x 500 km. This area contains significant infrastructure for gas processing and transportation and is located less than 300 km from the main transmission pipelines serving the Western part of Russia and export markets.

Figure 8: Flaring of APG by region in BCM, 2010-2012



Source: WWF Russia

Eastern Siberia has become the key new frontier in the Russian oil and gas sector. It has significant undeveloped reserves and is relatively close to Asian-Pacific markets. However, it covers a large geographical area and many of its fields are located far from other fields and existing infrastructure. In 2012, this region, which includes Tomsk, Krasnoyarsk and Irkutsk, for the first time flared more APG than Western Siberia’s Khanty-Mansisk region, the previous leader – despite producing only one quarter the amount of APG. According to satellite data, APG flaring in Eastern Siberia occurs at fewer than 30 oil fields, and more than 80% of this comes from only eight fields. In Krasnoyarsk, the rise in flaring since 2009 is primarily caused by the Vankorskoye field, developed by Rosneft. In Tomsk, flaring almost doubled between 2006 and 2010, albeit from a comparatively low level.

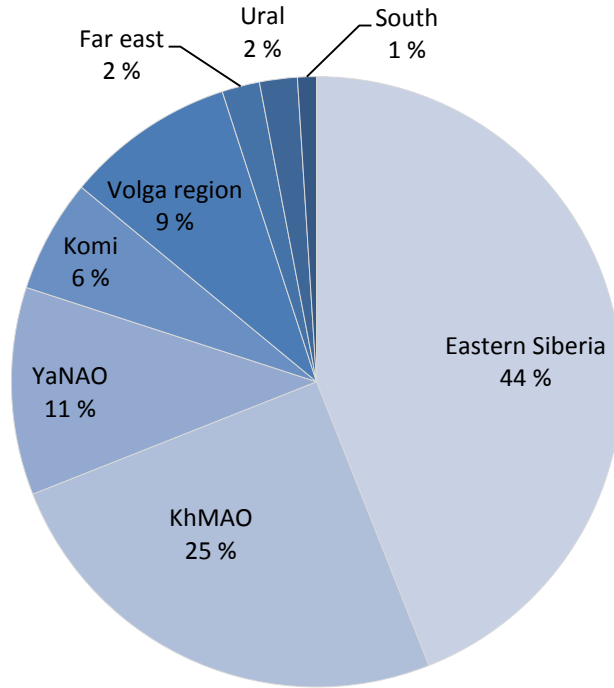
In the Timan-Pechora region, which notably includes the Komi Republic and the Nenets Autonomous District, funding for oil development and production significantly exceeds investments in gas processing, particularly in the northern part of Nenets. Given the high reserve potential, sparse population and lack of gas transportation options in this district, it is expected that the region as a whole will have a relatively low APG utilization rate in coming years.

The bulk of the flaring in the Volga region takes place in Orenburg, a significant portion in oil fields with a long production history. The area has significant gas infrastructure, including a number of gas processing plants and connections to the main gas transmission system – factors that imply significant opportunities to decrease flaring in coming years.

In summary, while flaring is showing a positive trend in some traditional oil-producing regions, due to improvements in gas infrastructure availability and market access, this is offset by increased flaring in “new” oil and gas provinces due to the growth in APG output and delays in introducing necessary infrastructure for utilizing the gas. However, the split of flaring by region shown in *Figure 9* may overestimate the dominant role of Eastern Siberia. Undoubtedly, there is a certain level of under-reporting of flaring in Russia, and it is likely that most of this is at older flare sites such as those in Khanty-Mansisk,

rather than at new production sites, such as those in Eastern Siberia, which tend to have more modern gas monitoring equipment.

Figure 9: Share of APG flaring by region in 2012



Source: WWF Russia

2.1.2 Regulations and policies

In the past, lack of an effective legislative framework for dealing with APG, combined with inconsistent enforcement, led to under-investment in infrastructure for APG utilization. In his April 2007 State of the Union address, President Vladimir Putin announced his intent to make better APG utilization a national priority. Since then, several national and regional government agencies have been investigating ways to increase gas utilization and have drafted a series of proposals to reduce flaring. For example, a working group on APG utilization was formed in the Ministry of Energy following a meeting chaired by President Putin in November 2009. One of its tasks was to suggest improvements to the regulatory and legal framework.

Government solutions have been largely punitive, e.g. licence requirements with a 95% utilization target coupled with increased penalties for non-compliance. However, some incentives to reduce flaring also have been introduced, including some market liberalization and preferential market access for flaring-reduction projects, including use of APG in power production.

Oil and gas production activities are enabled through license agreements, usually signed by the Ministry of Natural Resources and Environmental Protection, as well as relevant regional authorities. In some regions, most notably in Khanty-Mansiysk and Yamalo-Nenets, it is mandatory to include an APG

utilization percentage in the licence agreement. In theory, the right to use the subsoil can be withdrawn if essential license conditions are violated (Article 20), though to date there have been no license revocations due to failure to fulfil APG utilization rates, despite reported widespread non-compliance with APG utilization conditions specified in licence agreements.

According to Article 16 of the 2002 Law “On environmental protection”, emissions to the atmosphere should be compensated by the entities causing such pollution, and any activities harmful to the environment must be authorized with a permit issued by regulatory authorities. Different payments apply for different types of pollutants relevant to APG, depending on whether the operator stays within “established emission limits”, within “temporarily agreed emission limits” or produces “above-limit emissions”, according to thresholds established in individual permits. A basic rate is applied to emissions within the limits, but if emissions exceed such limits, the payment rate is multiplied by a factor set by law.

Government Decree No. 1148 of 8 November 2012 sets the multiplier at 12 for penalties on emissions greater than 5% of produced APG and raises the multiplier to 25 as of 2014 (Article 2). In the absence of acceptable measuring equipment at a field, penalties are multiplied by a factor of 120 (Article 5), although it is not clear how this is to be calculated in the absence of metering. The law does not apply the multiplier in some cases for fields where cumulative production is less than or up to 5% of estimated recoverable reserves (Article 3), and for fields where the annual volume of APG production is less than 5 million cubic meters, or for which the volume of non-hydrocarbon components represents less than 50% of the gas (Article 6). However, the new law apparently does not take into account remoteness of location as a factor deserving special consideration.

Decree No. 1148 allows producers to subtract investment costs for APG utilization projects from the fines, including for investments in gas pipelines, compressor stations, separation units, facilities producing electricity and heat and for re-injection (Article 8). It also allows a company to reach the 95% utilization target by aggregating production across all of a company’s fields. However, if the company is not able to reach this rate through aggregation, fines are calculated for each field individually (Articles 11-15). While this flexibility could lead to some economic efficiencies in targeting APG utilization investments, it could disadvantage companies that have a small number of fields.

According to the Ministry of Natural Resources and Environment, Decree No. 1148 of 2012 is expected to stimulate investments of around RUB 44.4 billion (EUR 1 billion) in APG utilisation projects.⁴

Additional economic incentives to increase utilization of APG include the liberalization of APG pricing in February 2008. This has helped increase oil companies’ bargaining power with Sibur⁵, which has had a quasi-monopoly on APG processing facilities. Amendments in December 2012 (No. 241-Φ3) to the 1999 Law on Gas Supply give priority access to free capacity in gas transportation infrastructure to stripped dry gas produced from APG. The Duma has also amended the Russian tax code to reduce the mineral extraction tax rate for produced natural gas volumes re-injected to maintain reservoir pressure. (See below for incentives related to APG use in the power sector.)

⁴ WWF webpage <http://www.wwf.ru/resources/publ/book/837>

⁵ SIBUR Holding OJSC (Sibur) is a 100% subsidiary of Gazprom

2.1.3 Investments and barriers

While flaring in Russia is perceived to represent a socio-economic loss of billions of dollars each year⁶, it has remained the most economically rational way to dispose of APG for many oilfield operators. Until recently at least, the risk of penalties for non-compliance with license obligations (up to license revocation) has been perceived as limited, and the economic attractiveness of investments in necessary infrastructure to utilize APG has been insufficient, due to limited cost savings from avoided payments for emissions of pollutants and the significant capital expenditures required.

Many oil fields are located far from markets and/or infrastructure and have been developed without infrastructure necessary to productively utilize the APG. Moreover, most Russian oil-producing regions have sparse populations and little local demand. As a result, the utilization of associated gas has been relatively low in Russia compared to the situation in many other oil-producing countries.

Below is a brief review of investments in some of the most important APG utilization options.

Gas processing

In 2010, 48% of produced APG was supplied to gas processing plants, where it was used as feedstock for production of marketable hydrocarbon products such as dry stripped gas, liquefied petroleum gas and stable gas condensate. Due to the high liquid content of many APG streams, expanding gas gathering networks and increasing the available gas processing capacity represents one of the most promising options to reduce flaring in many oil-producing regions in Russia, particularly in areas with significant existing infrastructure.

While gas processing has been a profitable business in Russia, regulated prices for APG supplied to third-party gas processing plants historically have been too low to encourage producers to invest in APG gathering and transport facilities. Despite price liberalization in 2008, prices from the sale of APG feedstock have not increased enough to justify recovery in many regions. This is partly due to lack of available processing capacity, which weakens the negotiating position of upstream suppliers. In 2010, 56% of processed APG was supplied to GPPs controlled by Sibur. Some upstream operators have entered into joint ventures with Sibur to secure long-term contracts for access to the latter's processing capacity and for sales of processed products.

Sibur has been implementing a corporate investment program to increase APG processing to 22.5 BCM by 2012, up from 15.2 BCM in 2008. This includes a number of joint projects with Russian oil companies. For example, Rosneft and Sibur have launched a joint-venture to process APG from the Priobskoye field at the Yuzhno-Balyk gas processing plant (owned by Sibur), and TNK and Sibur have jointly invested in the Yugragazpererabotka gas processing plant.

Other investments in gas processing facilities conducted by the Russian oil companies themselves include the following:

⁶ According to Russia's Natural Resources Ministry the companies' inappropriate use of APG costs Russia's USD 13 billion each year (<http://www.oilandgaseurasia.com/articles/p/115/article/1143>).

- Surgutneftegaz completed the construction and commissioning of its third APG treatment unit in Surgut in 2006. (In the 1990s, the company had acquired the Surgut gas processing plant, which today has a total processing capacity of 7.2 BCM.)
- Rosneft has invested in construction of three APG treatment units in Yamalo-Nenets: at the Komsomolskoye Severnoye field, at the Kharampur group of fields⁷, and at the Tarasovskoye field.
- TNK-BP has started construction of the Pokrovskaya gas treatment unit in Orenburg.
- Upon completion, processing capacity will be made available at Rosneft's Otradnevsky gas processing plant in Samara⁸. In 2012, construction, assembly activities and equipment supply for the second stage of the Zaykinskoye gas processing plant in Orenburg was also planned.⁹
- JSC Yugra Gas Processing has constructed a mini gas processing plant at the Zapadno-Salymkoye oil field.

In combination, these investments have over the past few years added processing capacity of more than 5 BCM/year.

Sale of dry stripped gas

Gazprom has a de facto monopoly on gas exports¹⁰, and oil producers are obliged to sell dried stripped gas (from processing APG) in the domestic market. With the emergence of new players in the gas sector, a two-tier market has been created: Gazprom has been forced to sell gas at low regulated prices, while non-Gazprom players are able to charge higher prices. However, access to gas transportation pipelines historically has been a problem.

Transport of dry stripped gas in Russia is primarily performed through the Unified Gas Supply System,¹¹ which is under the control of Gazprom. The Federal Tariff Service oversees a third-party access regime, which has been in place since 1998. (The amount of gas transported on behalf of non-Gazprom entities was 86.5 BCM in 2012, up from 64.5 BCM in 2010.¹²) In principle, Gazprom satisfies requests for access except where it is prevented from doing so for technical reasons. As noted above, amendments in December 2012 to the Gas Supply law give dry stripped gas from APG priority to available capacity in the Unified Gas Supply System. Unfortunately, the system operates at near full capacity, particularly the pipelines of the southern corridor running south from Yamalo-Nenets Autonomous Okrug, while pipelines running south from Nizhnevartovsk suffer capacity restrictions during winter. Major capacity increases

⁷ Comprising Festivalnoye, Kharampurskoye and Ust-Kharampurskoye (field names as defined by IHS)

⁸ <http://www.gulfoilandgas.com/webpro1/main/mainnews.asp?id=8762>

⁹ http://annual-report-2010.tnk-bp.ru/en/exploration_and_production/production_at_mature_fields/ Currently inaccessible due to integration of TNK-BP into Rosneft
<http://www.bp.com/sectiongenericarticle.do?categoryId=9009631&contentId=7018796> . New source:
<http://ir.tnk-bp.ru/~media/Files/T/Tnk-BP-IR/documents/annual-reports/ar-tbh-2010-eng.pdf>

¹⁰ Confirmed by the Gas Export Law adopted in 2006

¹¹ UGSS is the largest gas transportation system in the world, linking the production fields to customers throughout Russia, and represents a processing complex including gas production-, processing, transportation-, and storage- and distribution facilities. The total length of the UGSS exceeds 160,000 km.

¹² <http://gazpromquestions.ru>

will only be possible following significant reconstruction of the gas transportation system, although building more underground gas storage facilities near consumption centres would help reduce the problem.

In practice, many potential APG utilization projects initiated by oil companies have not been implemented due to the inability to ensure access to the transport infrastructure necessary to market dry stripped gas, including because of capacity problems. Moreover, Gazprom's control of information relative to gas transport and capacity bottlenecks has led to a lack of predictability and has inhibited independent producers' ability to envisage long-term contracts.

Electricity generation and sales

Amendments to the Federal Law "On Electricity" were adopted in 2010, facilitating priority access to the Unified National Electricity Grid for power produced from APG and its derivatives. Due to the extensive scale of the Russian grid network, there are significant opportunities for the export of the energy inherent in APG in the form of electricity.

For oil fields far from the interconnected grid, local power generation may represent the most attractive way to beneficially utilize APG. Fields in areas such as Timan-Pechora, the western parts of Khanty-Mansisk, Tyumen and Eastern Siberia cannot be supplied with electricity from the centralized power grid, at least not without significant investments in new power infrastructure. In these cases, the traditional solution has been to use localised diesel-powered plants. During the past five years, a large number of oil fields have installed small-scale gas turbine power plants to increase APG utilization, in part to avoid costs related to investments in (or the leasing of) diesel-fired power plants and the fuel to run them.

In the traditional oil-producing regions of Russia, power needs for oil-field operations are commonly met from electricity purchased from the grid. For example, in Khanty-Mansisk, many fields are supplied with electricity by the Urals branch of the United Energy System. Historically, this has provided for reliable and flexible power supply at modest costs. With the gradual liberalization of the power sector, however, the cost of purchased electricity has increased by as much as 20% annually in some areas. Several captive power plants burning APG have been installed to partly or fully offset purchased electricity, ensure sufficient power supplies to sustain/expand oil production in areas with old or constrained distribution systems and to increase APG utilization rates. For example, a 315-MW captive gas turbine power plant (the largest of its kind in Russia) was recently commissioned at the Priobskoye field to meet on-site needs. The field previously had been supplied with electricity from the grid. In addition to APG produced locally, the plant relies on a back-up supply of non-associated gas from the gas transmission system, in order to handle fluctuations in APG availability.

In areas with limited markets for dry stripped gas and non-existent or limited opportunities to export gas, efficient large-scale power generation and export of electricity to the grid could represent an attractive way of ensuring maximum APG utilization. For example, in 2008, TNK-BP established a joint venture with the power generation company Oskarshamns verkets Kraftgrupp AB to operate and construct new power plants in Nizhnevartovsk. In addition to 1,600 MW of existing capacity, the joint venture in July 2011 announced construction of an additional 400-MW power generation unit to be commissioned in mid-

2013¹³. This is the largest facility in Russia to be fuelled with dry stripped gas resulting from processing APG. According to TNK-BP, it will ensure uninterrupted supply of electricity to the company's production assets during a period when electricity tariffs are increasing (the region currently has a power deficit) and will provide a stable market for sale of the company's APG. This project serves as a good example of a situation where utilization of processed APG for grid-connected power generation is economically attractive.

Despite the priority that power plants using APG or its derivatives may have, it is generally challenging to manage such sales. This is because APG production fluctuates with oil production, making it difficult to manage vis-à-vis load changes in the grid, especially if supplied by a single field. This can result in a lower quality product than that supplied by a more conventional power plant. Moreover, decisions on capacity investment are complicated by the fact that oil and APG production volumes generally decline over time.

Carbon credits

Following a protracted process and delays, Russian authorities established procedures to approve projects developed under the so-called Joint Implementation mechanism of the Kyoto Protocol and to issue Emission Reduction Units that can be sold in the international carbon markets. The first project approvals were made in July 2010, and the first carbon credits were issued in December of the same year. Over 20 flaring-related Joint Implementation projects have been approved, and such projects now represent one of the largest categories of approved Joint Implementation projects in Russia.¹⁴ However, since 2011, Joint Implementation projects have become less important, partly because of a price collapse for carbon credits and partly because Russia made the decision not to join the second commitment period under the Kyoto Protocol, hence making new Russian carbon credits from such projects ineligible in carbon markets. It now seems unlikely that the emission reduction benefits of new APG projects will have any economic value for investors in the near future. However, there are processes internally in governmental institutions in Russia to design a national emissions trading system (a cap-and-trade scheme)¹⁵.

Petrochemical industry

The development of the petrochemical industry in Russia could have important implications for APG utilization. For example, according to one estimate, use of APG as a chemical feedstock in East Siberia could produce revenues of about RUB 12 million, compared to RUB 4 million for APG use in electricity generation.¹⁶ A company called "RusVinil" in Nizhegorodsk oblast is planning to open a polyvinylchloride factory in 2014 with a capacity of 300,000 tons per year.¹⁷

¹³ <http://www.tnk-bp.ru/en/center/releases/2011/07/8931/> Not available anymore due to the integration of TNK-BP into Rosneft

¹⁴ Despite the limited impact on investments per se, the interest in applying the JI mechanism has resulted in significant public awareness of what measures Russian oil companies have taken to address flaring in recent years, since project applications for JI eligibility are summarized in what is called Project Design Documents (PDDs), which have to be made public for stakeholder comments. PDDs include the technologies evaluated and applied to improve APG utilization and the economic and regulatory framework conditions for the investment.

¹⁵ <http://www.themoscowtimes.com/special/environment/eng/russia-mulls-internal-carbon-trading.html>

¹⁶ WWF webpage <http://www.wwf.ru/resources/publ/book/837>

¹⁷ WWF webpage <http://www.wwf.ru/resources/publ/book/837> (page 68)

Gas to liquids

Large oil companies in Russia, such as Rosneft, TNK-BP, Gazprom and GazpromNeft, are considering the application of gas to liquids for APG investments. International technology providers such as Velocys/Oxford Catalysts Group, CompactGTL and GasTechno are actively pursuing business opportunities in the country. There are also a few domestic companies active, notably INFRA Technologies and Energysyntop. For example, Rosneft, in partnership with the Russian firm Gazohim Techno, is building a gas-to-liquids demonstration plant at Rosneft's Angarsk Petrochemical Complex in Irkutsk Oblast. The plant will utilize the APG from several remote small and medium-sized fields and have a throughput capacity of 10 million cubic meters of gas per year, from which it will produce approximately 100 bbl/day of synthetic crude. This demonstration project is envisioned as the first of many commercial gas-to-liquid plants utilizing APG.¹⁸

2.2 Kazakhstan

2.2.1 Flare levels and trends

Kazakhstan has 30 billion barrels of proven oil reserves, the largest in the Caspian region. Oil production was 1.7 million barrels per day in 2012¹⁹. Proven gas reserves are 1.3 trillion cubic meters, and production in 2012 was 19.7 BCM. A large part of this was associated gas.

There are currently 172 oil filed and 42 gas condensate fields²⁰ in Kazakhstan, of which more than 80 are fields under development. The largest oil field is the offshore Kashagan field in the North Caspian Sea. Operated by a consortium including ENI, Shell, Total, ExxonMobil and KazMunaiGas, ConocoPhillips, INPEX²¹, the Kashagan started production later in 2013 up to the design capacity from 180,000 bbl/day in the first stage to 370,000 bbl/day²² in the second stage and reach a plateau of 1.5 million barrels per day by 2025. Tengiz, operated by the Tengizchevroil consortium, currently produces about 0.5 million barrels per day and may reach 1 million barrels per day by 2020. Karachaganak is a gas condensate field in northwest Kazakhstan that produced 140 million tons of oil equivalents in 2012 and is operated by a consortium including ENI, BG, Chevron and Lukoil.

According to official data 1 BCM of APG was flared in 2012 down from 3.1 BCM in 2006. The decline in flaring has happened despite a marked increase in crude oil and APG production over the same period. The flare intensity (flaring per unit of oil production) was in 2012 only 1/3 of the level recorded in 2006 according to national statistics. It should be noted however that there are major discrepancies in reported flare volumes between the official sources and flare estimates based on satellite images published by

¹⁸ Press release by Oxford Catalysts <http://www.oxfordcatalysts.com/press/pr/ocgtpr20120516.php> Not available anymore, but references to the deal at <http://www.bloomberg.com/news/2013-01-04/billionaire-roman-abramovich-buys-3-5-stake-in-oxford-catalysts.html>

¹⁹ BP statistical review 2011

²⁰ http://www.encharter.org/fileadmin/user_upload/Publications/Kazakhstan_ICMS_2013_ENG.pdf,

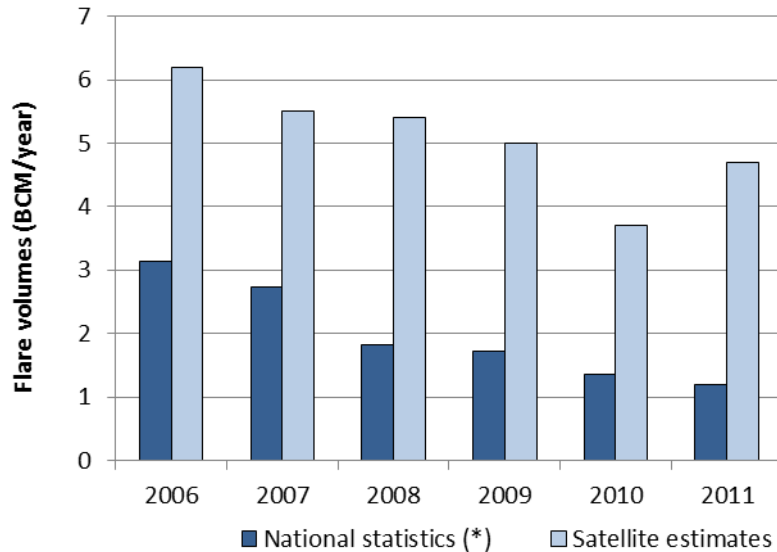
²¹ <http://www.offshore-technology.com/projects/kashagan/>

²² http://www.upi.com/Business_News/Energy-Resources/2013/07/18/Kashagan-oil-field-close-to-production-off-Kazakhstan/UPI-60921374150101/

GGFR based on data provided by NOAA. The latter is three times higher and shows only a modest decline and actually an increase from 2010 to 2011, see *Figure 10*.

As discussed in **Section 1.2** discrepancies between official statistics and satellite estimates are caused by three factors: i) errors and inaccuracies when converting “sum of light” from satellite images to flare volumes ii) inclusion of flaring from non-associated gas in satellite estimates iii) underreporting in national statistics. It is difficult to quantify the contribution of each factor, but it is likely that all play a significant role.

Figure 10: Flare volumes in Kazakhstan according to national statistics and satellite image estimates



Source: National statistics from Ministry of Oil and Gas Kazakhstan, satellite estimates from and NOAA/GGFR

Although data from satellites may not be suitable for statistical purposes they offer a good indication of the location of flaring and broad estimation of flare sizes, however with the caveat that the satellite data used for this Study are from 2011.

Some 37 oil fields with associated gas production have been identified as having flares. While most have low flare volumes, about half of APG flaring comes from just 12 fields, and one field, Zhanazhol, accounts for more than 20% of all flaring. The Karachaganak gas condensate field is the main source of non-associated gas flaring.

About 95% of all flaring is clustered in four areas: Caspian Sea and Coast (referred to here as zone 1), Aktobe (zone 2), the Kumkol basin (zone 3), and North West Kazakhstan near the border with Orenburg (zone 4). *Figure 11* shows the respective share of each zone in the 2010 flaring total.

Zone 1

Most of the flares in an around the Caspian Sea (zone 1) are midsize and primarily located at the Tengiz, North Buzachi and Kalamkas fields. Important projects to decrease flaring in this region in recent years include the following:

Figure 11: Kazakhstan - overview of the main flaring areas



Source: Carbon Limits based on NOAA and IHS data

Tengiz field gas utilization: In January 2010, Tengizchevroil completed a 4-year USD 258 million gas utilization project to eliminate routine flaring at Tengiz. Previously flared gas is being used as fuel on site, processed and sold in the market or re-injected into the reservoir for enhanced oil recovery. The Tengiz Gas Processing Plant is owned by LLP “Tengizchevroil” and has a design capacity of 12 BCM/year. When the field reaches maximum production, it is expected that one third of the produced gas will be injected into the reservoir and the remaining amount will be processed. Though routine flaring has stopped, intermittent and emergency flaring still takes place.

North Buzachi: A new APG utilization complex opened in 2009 that includes gas collection systems and furnaces for burning wet gas and for heating oil and water, which is injected back to the reservoir to increase pressure and stimulate production.

Kalamkas: In September 2011, Mangystaumunaigas inaugurated a gas-fired power plant (90 MW) that should utilize all the previously flared gas.

Zone 2

The Aktobe region (zone 2) includes a number of flares dispersed around the Zhanazhol field and GPP.

CNPC-Aktobemunaygaz (85.15% CNPC and 14.85% KazMunaiGas) is the main operator in this basin. The largest flare volume has been identified in the Zhanazhol area, but another 0.6 BCM of gas is flared from some 19-20 medium and smaller sized flares. Some of the flares are located up to 90 km from gas pipelines.

Zhanazhol: The first train of a 2-BCM/year gas processing plant was commissioned in 2007 and the second 2-BCM train in 2009. The second stage of the Zhanazhol gas turbine power station was completed in 2010, increasing capacity to 110 MW and making it one of the largest gas consumers in the area.

Zone 3

Key companies in the South Turgay Sub-basin (zone 3) include CNPC-Ay Dan Munay (CNPC); KazGerMunay LLP (KazMunaiGas and CNPC); and PetroKazakhstan Kumkol Resources (KazMunaiGas and CNPC). A number of gas utilization projects have been ongoing over the past few years in this area, including the following:

PetroKazakhstan: Development of a gas utilization plan, which includes a 55-MW gas power plant commissioned in 2004 and gas re-injection facilities at South Kumkol, Aryksun and Maybulak fields²³. Small power plants were also constructed at a number of fields in 2009, and another 55-MW power plant was commissioned in 2010 using gas from the North Nurali field.

Kumkol gas processing: An associated gas processing plant was put into operation in October 2009 on the Kumkol field. The plant has a designed capacity of 150 million cubic meters per year.

Akshabulak: Kazgermunai's Akshabulak gas processing plant has been in operation since 2004, providing dry gas to the city of Kyzylorda. In December 2011, the first unit of a new gas turbine power plant began using associated gas from the Akshabulak field. Early in 2012 two more turbines will be commissioned, bringing total capacity to 87 MW.

Kenlyk: The Eurasian Development Bank financed a facility commissioned in 2010 to collect and process associated gas at the Kenlyk field. It currently produces about 50,000 tons of LPG (commercial propane/butane mix and stable gas condensate) from 100 million cubic meters of feedstock gas.²⁴

Zone 4

North Kazakhstan (zone 4) includes only two flares, at Karachaganak and Chinarevskoye, both located close to GPPs and gas pipelines.

Karachaganak: The Karachaganak gas condensate processing complex started production in 2003. A large part of the sour gas produced by the Karachaganak field is re-injected, while remaining unstable condensate and raw gas are delivered to Orenburg, Russia, for processing²⁵.

Chinarevskoye, Zhaikmunay LLP: In October 2011, a gas treatment facility started operation to treat both gas condensate and associated gas. It has two trains, each with a capacity of 850 million cubic meters per year. Gas from this field can be exported, since Chinarevskoye is connected to the Soyuz Export pipeline to Orenburg, Russia.

2.2.2 Regulations and policies

Amendments to the Law on Oil (1995) prohibited flaring of associated gas as of 1st July 2006. The authorities initially sought strict enforcement of the new regulations with fines and threats to revoke production licenses. While this helped shift oil companies' focus toward APG utilisation, it soon became apparent that more flexibility in the regulations would be needed. Planning and implementation time

²³ Petrokazakhstan website <http://www.petrokazakhstan.kz/eng>, IHS database.

²⁴ http://eabr.org/e/projects/edb/index.php?id_4=174

²⁵ <http://www.kpo.kz/index.php?id=80&L=1>; <http://www.kpo.kz/index.php?id=80&L=1>

required for APG utilization investments were not adequately catered for in the regulations and initial enforcement practises. This was somewhat rectified in the new Law on Subsoil and Subsoil Use (“Subsoil Law”), adopted in June 2010. The legal conditions for flaring and disposition of APG were changed and technologically unavoidable gas flaring was allowed under certain conditions. Nevertheless, the Subsoil Law continues to prohibit flaring unless the Ministry of Oil and Gas grants a permit to do so.

Prior to the new Subsoil law, large quantities of APG were re-injected. The Subsoil Law discouraged re-injection by introducing an obligation to process the APG, with the aim of ensuring that more gas would be brought to market. Subsoil users are obliged to develop a program to use APG with limited exceptions. Such programs must be approved by the Ministry of Oil and Gas and updated every three years. Operators must report annually on implementation. Permission to re-inject must be explicitly granted by the relevant authority, though permission is subject to conditions less strict than those for flaring.

The Law on Gas and Gas Supply of 9 January 2012 (“Law on Gas”) further clarifies regulatory conditions for APG utilization and the commercial framework conditions for supplying gas, establishing the pre-emptive right of the State to purchase raw and commercial gas²⁶. A Government Resolution of July 2012 designates KazTransGas, owner and operator of most of Kazakhstan’s gas infrastructure, as the National Operator with pre-emptive purchasing rights. The Law on Gas obliges subsoil users to make an offer based on i) the recovery cost of the raw gas, ii) the transport cost to the National Operator, iii) the cost of producing commercial gas from the raw gas, and iv) a profitability margin of no more than 10%. After approval of this offer by the “Authorized Body” (supposedly the Ministry of Oil and Gas), the National Operator may accept or reject the offer. The law also gives the National Operator, KazTransGas, preferential rights to gas supply infrastructure²⁷ and to sales of gas, effectively restricting other companies’ commercial activities related to gas supplies.

The Subsoil Law and the Law on Gas also concern institutional roles and responsibilities for APG utilization and flare reduction. It gives the Ministry of Oil and Gas and KazTransGas authority to instigate measures to bring APG to productive use, including through fines. Flare-related payments are subject to complex regulations involving the Environmental Code, the Tax Code and the Code on Administrative Violations. Charges are paid for flaring and emissions within the authorized limits and for volumes above these limits, the latter many times higher than the former. A large portion of charges and penalties are collected and kept as revenues by the local authorities.

While the Ministry of Oil and Gas and KazTransGas have important instruments in place to spur investments in APG utilization, the pace and economic efficiency at which such investments can be achieved remains to be seen. Since APG production is spread over many oil and gas producers, a good dialogue and cooperation with these companies would seem to be essential.

Introduction of an emission trading system for CO₂ from 2014 may eventually also represent an incentive for productive use of APG. The emission trading system will in effect penalize flaring, but the implicit fine

²⁶ There are certain exemptions that apply, primarily related to the origin of the gas, e.g. gas from gas-condensate fields, LNG and certain categories of imported gas.

²⁷ Referred to as «Gas Supply System» in the Law.

(the price of emission allowances) will probably for the first few years be low and probably not make a significant difference for the economics of APG investments.

2.2.3 Investments and barriers

Most projections indicate a steady increase in Kazakhstan's domestic gas demand, e.g., the IEA forecasts an 2.2% average annual growth rate through 2035. The domestic gas market in Kazakhstan is dominated by the vertically integrated KazMunaiGaz through its subsidiary KazTransGas, though several large independent producers are present in the market. However, Kazakhstan's gas market is not open to competition, and gas is currently sold on the domestic market and for export at prices well below the international netback level.

The main barriers of the gas production in the Kazakh oil and gas sector, according to the Energy Charter Secretariat (2013) are:

- Lack of a developed gas transportation infrastructure for supply of gas to the northern and central regional markets of the country;
- Dependence on natural gas supplies from Uzbekistan and Russia;
- Lack of individual capacities for the processing of Karachaganak gas²⁸.

Power generation is a key utilization option for associated gas. The power sector is expected to be the biggest contributor to increased primary energy demand as the share of gas-fired power in total generation increases from 11% in 2008 to an expected 34% in 2035²⁹. There is currently more than 2GW of gas-fired plant installed, but more than ¾ of power generation still comes from coal. Private companies have entered the power generation market and have the possibility to conduct bilateral contracts with consumers, including 20 regional distribution companies with different forms of ownership. While wholesale power prices currently cannot be set higher than a maximum tariff defined for each plant type, this cap reportedly can be reviewed on a case-by-case basis.

Kazakhstan exports gas to Russia (Orenburg) from Karachaganak and via the Central Asia-Centre (CAC) pipeline. Kazakhstan is also a major transit country for exports from Turkmenistan and Uzbekistan. All gas transportation is carried out by "KazTransGaz" (100% owned by KazMunaiGaz) and its affiliated companies.

As natural monopoly gas transport services charged with tariffs are to be approved by the Agency regulating natural monopolies³⁰. According to the Law on Natural Monopolies, tariffs should not be below the cost of regulated services (goods, works) and shall ensure profit for an efficient provision of the services by natural monopolies. Establishment of the Common Economic Space (CES) in Kazakhstan, Russia and Belarus on 1 January 2012 will have implications to the tariffs for hydrocarbons transit as

²⁸ http://www.encharter.org/fileadmin/user_upload/Publications/Kazakhstan_ICMS_2013_ENG.pdf

²⁹ IEA WEO 2010

³⁰ The tariff is defined according to the Methodology on calculation of tariffs on main pipeline transportation services, which is stated by the №500-ОД Decree of the Chairman of Agency from December 21st 2004.

unification of tariffs and nondiscriminatory access to pipeline systems of member countries are one of the main principles of the CES.

Historically, Kazakhstan has been dependent on Russia for gas export, however new pipeline projects will open more options for the country. There are currently three main pipeline projects:

1. The construction of the 1,475-km Beiney-Shymkent pipeline will reduce dependency on the supply of Uzbek gas by allowing gas to be transported from western to southern Kazakhstan, where there is high demand, crossing Mangystau, Aktobe, Kyzylorda and Southern Kazakhstan oblasts along the way. It will also allow another export option for Kazakhstan by connecting to the Turkmenistan-China pipeline.
2. The construction of the 1,304-km Kazakhstan-China main pipeline will allow increased transportation of gas from Central Asia to China, as well as the supply of gas to southern Kazakhstan and the transit of Turkmen gas. The two first lines were commissioned in 2009 and 2011. The transit volume in 2009 was approximately 14.5 BCM, and by the end of 2012 is planned to reach 30 BCM, with a future rise to 40 BCM.
3. The construction of Kartaly–Tobol–Kokshetau–Astana gas pipeline with a capacity of 1.5 BCM/year is aimed to provide gas supplies to the northern parts of Kazakhstan including the capital Astana. The cost of the construction is estimated to be above KZT 200 billion (EUR 970 million); State welfare Fund Samruk-Kazyna will allocate KZT 120 billion in 2013³¹. The design and estimate documentation is reaching completion and, with availability of funds, the construction of the pipeline should start in 2013.

In 2007, Russia and Kazakhstan signed an agreement on cooperation to construct the Caspian Coastal pipeline, which would run along the Caspian coast from Turkmenistan via Kazakhstan to Russia. Reportedly, “the gas pipeline is intended to provide transportation of 20 BCM of gas to world markets annually, including up to 10 BCM of Kazakh gas and up to 10 BCM of Turkmen gas”³². The project is currently postponed due to [suspended] negotiations between Russia and Turkmenistan.

³¹ <http://www.kazenergy.com/ru/press/2011-04-21-10-24-20/6712-----2013-----120--.html>

³² http://www.encharter.org/fileadmin/user_upload/Publications/Kazakhstan_ICMS_2013_ENG.pdf

Figure 12: Main regional pipelines projects ³³



the boundaries and names shown and the designations used on the maps included in this publication do not imply official endorsement by the IEA

Source: IEA World Energy Outlook 2010, Carbon Limits analysis

A number of projects for gas utilization currently planned or under construction at particular fields (presented according to the zones in Figure 11) are:

Zone 1

Kashagan/Bolashak GPP: During Phase I, around half of the gas produced at Kashagan will be re-injected into the reservoir, while separated liquid and raw gas will be taken by pipeline to the Bolashak onshore processing plant in Atyrau oblast. Some of the processed gas will be sent back offshore for use in power generation and some will be used to generate power at the processing plant itself.³⁴ The implementation of the project will allow the company to process 400 million cubic meters of associated gas and produce 320 million cubic meters of dry commercial gas and 57,000 tons of liquefied gas (propane/butane mix) per year³⁵. The total investments in the Kashagan Project were estimated at USD 136 million.

Barankol GPP: The construction of the Barankol GPP started in 2005, but has been halted due to financial difficulties.

Tengiz: Tengiz GPP has a design capacity of 2.55 BCM of gas per year. A 100-km gas export line is planned from Tengiz to the Central Asia Center pipeline³⁶. There has also been discussion of increasing gas-powered generation capacity at the field.

³³ IEA WEO 2010, Carbon Limits analysis

³⁴ http://www.ncoc.kz/en/kashagan/development_strategy.aspx

³⁵ <http://kazworld.info/?p=18318>

³⁶ IHS midstream essentials

Prorva group of fields (south of Tengiz): Different options for gas pipeline connections for the Prorva group of fields were evaluated in 2011, but implementation is currently unclear.

Zone 2

Aktobe: In 2012, Kazakhoil Aktobe is planning to open a new complex capable of processing 400 million cubic meters of APG per year, 320 million cubic meters of dry gas and 57,000 tons of LPG³⁷.

Zhanazhol gas processing plant expansion: In 2013 there are plans to complete construction of the next phase of a GPP, increasing capacity to 6 BCM/year.

Zone 3

Akshabulak Gas Power plant: The plan is to increase the capacity of this gas-fired power plant to 127 MW by 2014.

2.3 Turkmenistan

2.3.1 Flare levels and trends

Turkmenistan's proven oil reserves are roughly 600 million barrels³⁸, considerably less than those in neighboring Kazakhstan and Azerbaijan. Most of its 62 producing oilfields are situated in the South Caspian Basin and the Garashyzlyk onshore region in the west of the country. Oil production has remained around 200,000 bbl/day for the past ten years and about half is exported. Most of the growth in oil production in recent years has been offshore, particularly from the Cheleken field operated by Dragon Oil.

Estimates of Turkmenistan's proven natural gas reserves vary from 8 trillion cubic meters to more than 20 trillion cubic meters³⁹. The country has several of the world's largest gas fields, including the Galkynysh (formerly known as South Yolotan), with potential reserves exceeding 13 trillion cubic meters⁴⁰. The expected capacity of the Galkynysh gas field from 2013 is 30 BCM of marketable gas per year⁴¹. Total gas production in Turkmenistan peaked at about 66 billion cubic meters (BCM) in 2008, but fell to 36 BCM in 2009 following a blast on the Central Asia-Center gas pipeline. Production has since recovered and stood at 64.4 BCM in 2012.⁴² Gas accounts for almost 80% of total primary energy demand. Some 50%⁴³ of gas production is exported and most incremental production will go to exports as supply recovers.

Contrary to the situation for the other countries of this study, there are no official published figures for flaring or venting for Turkmenistan, though the country's National Communication to the United Nations Framework Convention on Climate Change suggests that some 2-2.5 BCM of gas was vented or flared in

³⁷ http://www.oilcapital.ru/news/2011/07/270605_170262.shtml

³⁸ BP statistical review 2011

³⁹ IEA WEO 2010, BP statistical review 2011 and the Turkmen government 2006

⁴⁰ Figure depends on the source

⁴¹ http://www.oilgas.gov.tm/publish25_4.html

⁴² BP statistical review 2013

⁴³ BP statistical review 2013

1998. According to the same document, in 2006 about 40% of previously flared gas was used for the production of liquefied gas at the Turkmenbashi refinery and for gas lifting.

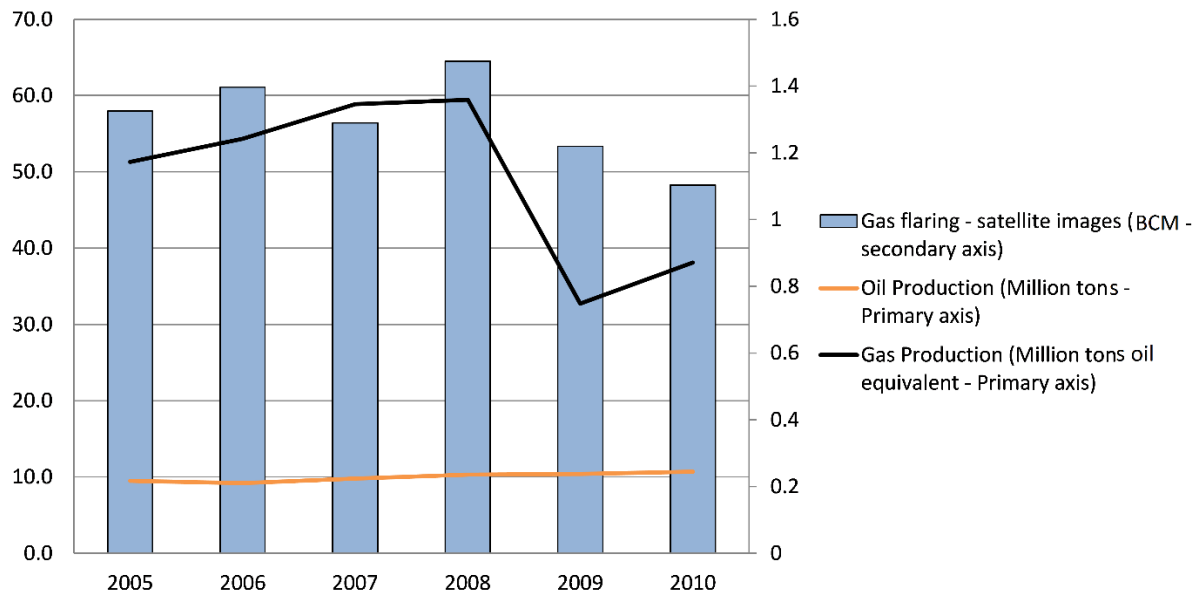
NOAA estimates from satellite images suggest that gas flaring has remained somewhat above 1 BCM/year since 2005. According to this source, flaring has been falling since 2008, with a 10% drop between 2009 and 2010, despite the rebound in gas production and a moderate increase in oil production.

Some 57% of flaring in Turkmenistan concerns non-associated gas, e.g., from gas or condensate fields. Individual flares of associated gas are mainly midsized, while flaring for non-associated is dominated by one field, the Yashildepe (Kokdumalak). In terms of fields' ages, most of the flares are at fields developed before 1990.

Mary is the region with the highest gas reserves (15.5 trillion cubic meters recoverable⁴⁴), though only one small flare has been identified in this region. The development of the large Yolotan field may lead to additional flaring in this region⁴⁵.

Lebap is one of the principal gas regions in Turkmenistan, and flaring here concerns mostly non-associated gas. The main flare in Lebap is close to the Yashildepe field, near the border with Uzbekistan (and may actually be located just over the border). All flares in this region appear to be located in the vicinity of gas pipelines.

Figure 13: Gas flaring estimates from NOAA over time compared to production data



Source: NOAA

The Caspian Basin is composed of the Balkan onshore region, dominated by the Turkmen government operator, and the Caspian Sea offshore region, managed by foreign investors Petronas and Dragon Oil. Some 90% of the flaring in this region comes from fields producing primarily oil, though almost all flares

⁴⁴ IHS E&P copyright © IHS 2011. All right reserved

⁴⁵ The current situation is quite uncertain at this field.

are located in the vicinity of some gas infrastructure. About 2/3 of the flaring in this region is due to just three fields: Akpatlavuk and Keymir, operated by Balkanbebitgazsenagat, and Jeytun (LAM), operated by Dragon Oil. The latter is the largest contributor to flaring in the region, and is responsible for most of the increase between 2006 and 2008, when oil production from this field substantially increased. Gas re-injection for pressure maintenance has been on-going in some of these fields.

2.3.2 Regulations and policies

Since March 2007, the State Agency for Managing and Using Hydrocarbon Resources (Agency) has been given broad authority in oil and gas matters. The Agency took over many of the powers of the Ministry of Oil and Gas Industry and Mineral Resources, including issuance of licenses. It is also responsible for all matters related to the use of hydrocarbon resources, including gas exports and construction of gas pipelines. The Agency is also in charge of environmental regulation vis-à-vis oil and gas companies, including for flaring and venting. The Agency operates directly under the President, who nominates its Director.

The “Rules for the Development of Hydrocarbon Fields” of 22 October 1999 states that, *“an Operator may flare or vent gas without receiving prior approval from the Competent Body only in the following situations: (i) when gas is flared or vented in small volumes from storage vessels or other low-pressure production vessels and cannot be economically recovered, and (ii) during an equipment failure or to relieve system pressure.”* The Competent Body is defined as the “State Body, to which the Cabinet of Ministers delegates powers to issue Licenses and enter into the Contracts with the Contractors”.

In general, regulations specify that the operator must not flare or vent gas for more than 48 continuous hours, more than 144 cumulative hours during any calendar month, or beyond the time required to manage emergency risks, unless otherwise approved by the Competent Body. Gas flaring or venting can be allowed for a “reasonable” period of time in compliance with “international oil field practice” for certain operations, including the unloading or cleaning of a well, well testing, wireline intervention or well stimulation. Moreover, the Competent Body may allow the operator to flare or vent gas for up to one year if the action, when completed, is expected to eliminate flaring or venting. The Competent Body may also allow flaring for up to one year if the operator has submitted an evaluation, supported by engineering, geological, and economic data, indicating that the oil and gas produced from the well will not economically support the facilities necessary to store or sell the gas, or that there is no commercially viable market for the gas. According to the regulations, operators must prepare a report which is submitted every three months to the Competent Body detailing gas flaring or venting and liquid hydrocarbon burning for each facility. The reports must include: daily volumes, numbers of hours, reasons, and a list of the wells involved, along with gas-oil ratio data.

The level of compliance with, [and enforcement of], regulations is unclear, however, and case-by-case negotiation appears to be common.

2.3.3 Investments and barriers

Although the country aims to produce 187 BCM of natural gas and 23 million tons of crude oil (about 500,000 bbl/day) annually by 2020⁴⁶, the IEA projects a more modest growth in Turkmenistan's output, reaching 290,000 bbl/day of oil and 104 BCM of gas per year, of which 73 BCM would be for export.⁴⁷ Actual growth in oil and gas supplies will be highly sensitive to the country's ability to attract foreign capital and technologies.

Malaysia's Petronas operates Block 1 in the West Turkmenia (South Caspian) Basin in the Caspian Sea. In 2011, Petronas commissioned a gas treatment plant and onshore gas terminal with a capacity of 5 BCM/year, upgradable to 10 BCM. This consists of two process trains and a 53-km pipeline linking the terminal to the Central Asia Centre 3 export pipeline.⁴⁸ The facility will treat gas produced by the offshore assets of Petronas. In July 2011, Petronas signed a contract to sell 5 BCM/year to Turkmen gas at a price which has remained confidential.

Dragon Oil, a privately owned oil and gas company from the United Arab Emirates, has its main producing assets in the Cheleken Contract Area. Based on analysis performed for this study, it is estimated that Dragon Oil flared about 0.4 BCM of gas in 2010 from Cheleken and Jeytun (LAM) combined. Dragon Oil is currently implementing a project to stop its flaring activities in Turkmenistan⁴⁹. It has completed the phase-2 expansion of its central processing facility, which allows it to handle 2 BCM of gas, and has finalized the FEED study for a gas treatment plant. Since January 2011, Dragon Oil has been bringing a substantial portion of unprocessed gas onshore together with crude oil via its new integrated pipeline network. Petronas and Dragon Oil signed a MoU on gas utilization in 2003, but details are unknown.

In December 2009 Turkmen gas signed service contracts to develop the Galkynysh field with CNPC, South Korea's LG International and Hyundai Engineering and the UAE's Petrofac Emirates. As of May 2013, the total investment project was estimated at USD 10 billion aimed at creating the infrastructure for a production and processing of the gas with a capacity of 30 BCM per annum⁵⁰. Reportedly, the companies have drilled more than 20 wells⁵¹, constructed a pipeline system, four gas treatment units, three desulphurisation plants and some residential buildings.

In September 2010, Turkmenistan gave public support to an ENI project that would transport compressed natural gas via tanker across the Caspian Sea to Azerbaijan using the associated gas of Burun field.⁵² However the project currently seems to be on hold.

While Turkmenistan seeks foreign involvement in developing its offshore oil fields, it generally does not give foreign access to onshore gas reserves. Turkmen gas has exclusive rights to gas supplies, and as such

⁴⁶ Turkmen government official statement November 2011

⁴⁷ IEA World Energy Outlook 2010

⁴⁸ [http://mynewshub.my/2011/07/13/pm-launches-kiyanly-gas-treatment-plant/;](http://mynewshub.my/2011/07/13/pm-launches-kiyanly-gas-treatment-plant/)
<http://www.oananews.org/node/194678>

⁴⁹ Dragon Oil website <http://www.dragonoil.com> and presentations

⁵⁰ <http://turkmenistan.gov.tm/?id=4079>

⁵¹ <http://caspianbarrel.org/index.php/en/component/content/category/53-turkmenistan?layout=blog&limitstart=0>

⁵² http://www.staffettaonline.com/staffetta_news/articolo.aspx?ID=10097

has responsibility for gas and condensate field development and production, natural gas processing, gas transportation and gas sales to both domestic and export customers. There are currently no plans for future privatization or liberalization of Turkmenistan’s gas sector.

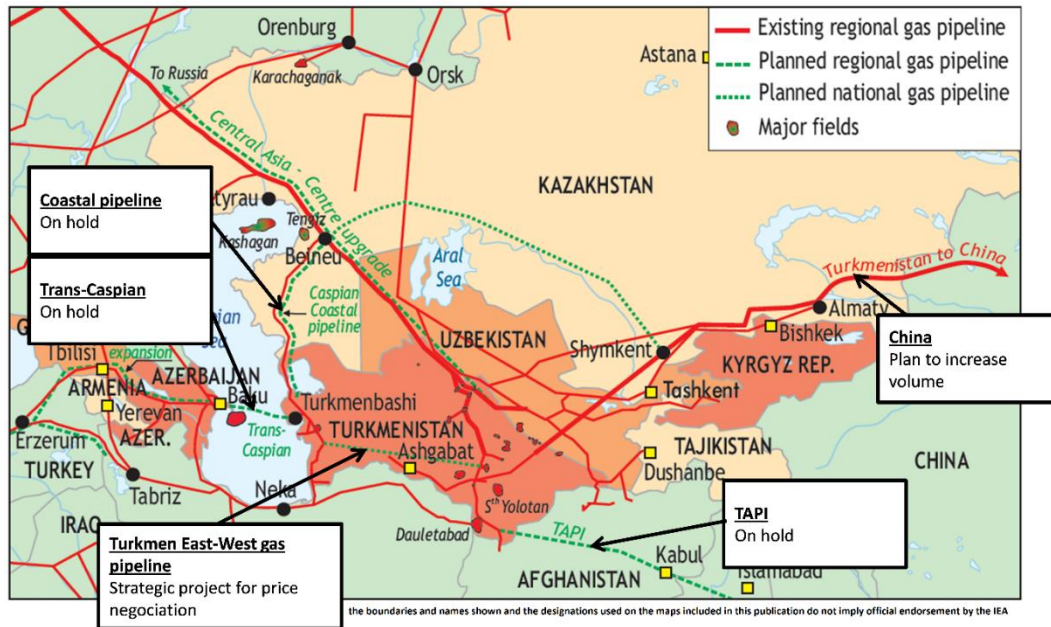
In rare cases where a foreign company owns an onshore gas field (as in the case of CNPC), there is a contract with Turkmen gas under which the company is obliged to sell at least a portion of the produced gas to Turkmen gas. There is no wholesale gas market in Turkmenistan, and Turkmen gas directly negotiates with potential foreign gas buyers. The gas pipeline network, which is owned, operated and controlled by Turkmen gas, is characterized by old and inefficient equipment.

Since the end of 2009, Turkmenistan has exported natural gas to Russia, Iran and China. The "Central Asia-Center" pipeline (CAC), built in the late 1960s, is still the most important export outlet, passing through Uzbekistan and Kazakhstan before entering Russia. Annual gas exports to Russia have fluctuated considerably, sometimes reaching over 20 BCM, though in recent years have been closer to 10 BCM.

Turkmen gas is exported to Iran through two pipelines: Korpeje-Kurtkuyi, built in 1997, and Dowletabat-Sarakhs-Khangiran, built in 2009, with a combined annual capacity of 20 BCM. Gas exports to Iran reportedly reached 8 BCM in 2010 and are expected to increase in the in the future.

Gas exports to China began in 2009 through the Turkmenistan-Uzbekistan-Kazakhstan-China gas pipeline. Although volumes in 2010 were only around 3 - 4 BCM, annual supplies are expected to reach 40 BCM by 2014-2015, when the pipeline reaches full capacity. During a visit of the Turkmenistan president to China, it was agreed that the annual supply volume of gas to China would be increased to 65 BCM by the end of 2015. Reportedly the corresponding agreements were signed during the visit of the President of the People's Republic of China on 3-4 September 2013 in Turkmenistan.

Figure 14: Overview of the gas pipelines projects in the region



Source: IEA World Energy Outlook 2010

Turkmenistan adheres to rigid rules and controls for export sales, and the government directly negotiates all gas export contracts. The transportation tariff is set by state-owned Turkmentransgas, agreed with Turkmengas SC, and approved by the Agency.

There are currently a number of new gas pipelines projects in Turkmenistan. The intention of Turkmenistan to develop a policy on diversification of the transport-transit network of the pipelines was highlighted by the President during the Non-Aligned Movement Summit on 30 August 2012⁵³. A proposed East-West domestic gas pipeline is designed to give Turkmenistan the ability to connect all large gas fields in Turkmenistan⁵⁴ and send gas to multiple export points on its external borders. The designed capacity of the 766 km long pipeline (with a diameter of 1420 mm) is 30 BCM/year. Reportedly, the costs of this project were estimated at about USD 2 billion⁵⁵.

A proposed Trans-Caspian sub-sea gas pipeline between Türkmenbaşy and Baku has been at various stages of discussion and negotiation since the late 1990s, though this project is currently on hold, despite support from both the US and European Union. Some experts state that if Turkmenistan and Azerbaijan come to an agreement on economic and political issues concerning construction of the pipeline, the project could be launched in 2018-2019⁵⁶. The Azerbaijan-Georgia-Romania Interconnector would provide gas supplies to the Caspian region, as well as to Romania via the Black Sea coast of Georgia. Turkmenistan may be involved in this project if the Trans-Caspian seabed gas pipeline is constructed.

In May 2012, the sales and purchase agreement on the natural gas was signed between Turkmenistan, India and Pakistan. This agreement concluded the second phase of the project on construction of the Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline⁵⁷. The parties of the Project also agreed to establish a TAPI Ltd. consortium.

A Caspian Coastal Pipeline is planned to run along the coast from Turkmenistan via Kazakhstan to Russia, though currently is on hold.

Since 1992, households have received free gas (600 cubic meters per person per year), though actual supplies are reportedly irregular, particularly during winter. Other customers pay regulated prices. Domestic gas demand in Turkmenistan is relatively high, which can be explained by a number of factors, including the low gas price, large technical losses in electricity and gas supply infrastructure, and the low thermal efficiency of the gas-fired power plants. The IEA⁵⁸ forecasts an average annual gas demand growth of 1.6% for the period 2008-2035 and further expects gas-fired electricity generation to increase from 15 TWh in 2008 to over 34 TWh in 2035.

Gas is the principal fuel for power generation, which is a major domestic outlet for gas supplies. Structural reform is not currently on the policy agenda for this sector, which consists of a single vertically integrated monopoly, Turkmenenergo. Electricity tariffs have changed very little since 1998 and do not cover costs. There is currently 4,100 megawatt (MW) of generation capacity, of which 2,800 MW is gas-fired. However,

⁵³ [http://www.oilgas.gov.tm/publish4\(2\).html](http://www.oilgas.gov.tm/publish4(2).html)

⁵⁴ <http://www.oilgas.gov.tm/publish7.html>

⁵⁵ <http://www.oilgas.gov.tm/publish7.html>

⁵⁶ <http://www.chrono-tm.org/2013/05/rossiya-nedovolna-planami-po-stroitelstvu-transkaspiskogo-gazoprovoda/>

⁵⁷ <http://www.oilgas.gov.tm/publish25.html>

⁵⁸ IEA WEO 2010

the system is characterized by old and inefficient equipment, and the average thermal efficiency of Turkmen gas-fired power plants is estimated at 25%, far below the world average⁵⁹. The Ministry of Energy and Industry plans the construction of four 125-MW units of gas-fired units at Gysyl-Atrek, near the Iranian border.⁶⁰

In 2010, Turkmenistan produced about 14.5 TWh, of which about 1.6 TWh was exported to Afghanistan, Kazakhstan, Iran, and Turkey. Exports to Tajikistan ceased in December 2009 after Uzbekistan (used for transit) withdrew from the Central Asia Unified Power Grid. The intention is to increase the power production up to 35.5 TWh by 2030 through modernization of steam-turbine plants and construction of new GTPP. In July 2013, a company "Çalik Enerji Sanayi ve Ticaret A.Ş." (Turkey) has signed two contracts for building of two GTPP⁶¹.

Three plants produce liquefied petroleum gas (LPG) in Turkmenistan. The first was put into operation in 1998 at the Naip gas condensate field and has produced 15,000 tons of LPG per annum and a similar quantity of gas condensate. In November 2002, the 2nd unit [at Naip] was put into operation with a capacity to process 9 million cubic meters per day and to produce 65,000 tons of LPG annually. The Turkmenbashi refinery on the Caspian Sea coast is the other main LNG producer. After modernization in 2002, its LPG production increased from 18 to 220,000 tons per year.

2.4 Azerbaijan

2.4.1 Flare levels and trends

Azerbaijan's oil production grew rapidly from 0.3 million barrels per day in 2004 to 1 million barrels per day in 2009, after which it has stagnated. Somewhat less than 80% of the production comes from the offshore fields Azeri, Chirag and Deepwater Gunashli (ACG), operated by BP and with a consortium of 9 international oil companies and the State Oil Company of Azerbaijan, SOCAR, as partners. Other important oil fields in terms of initial recoverable reserves are "Balakhany-Sabunchi-Ramany", "Shallow Water Guneshli", "Neft Dashlary" and "Bibiheibat" fields.

Gas production⁶², according to the BP Statistical Review, grew from 4.5 BCM in 2004 to 15.6 BCM in 2012. The increase was primarily caused by the start-up of production from the Shah Deniz gas condensate field. Gross production of APG from the ACG fields was 12 BCM, of which 60% was re-injected, some 25% was brought to land for domestic consumption or exports and 15% was used as fuels at the installations or was flared, flaring being somewhat less than fuel use.

The ACG fields account for the major part of flaring in Azerbaijan. Since 2009, when oil production reached a plateau, flaring has been in the range 0.5 to 0.7 BCM per annum, and the gas utilization rate has

⁵⁹ IEA WEO 2010

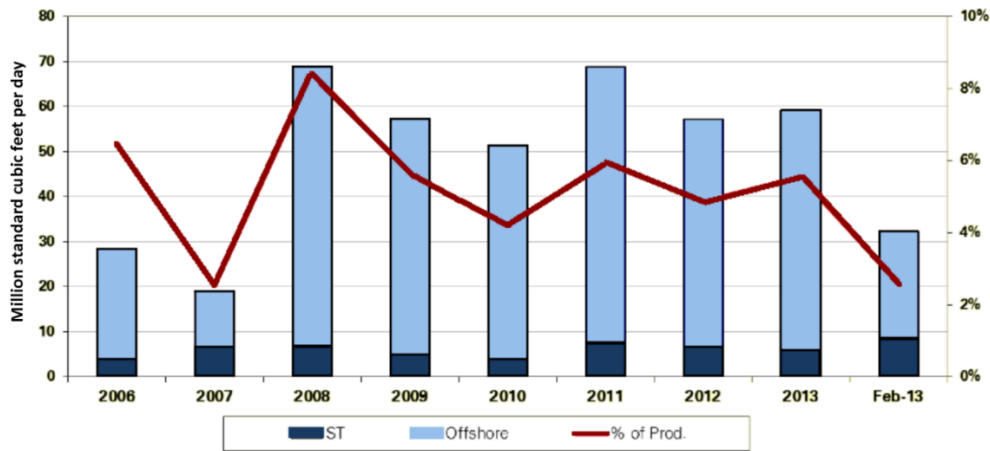
⁶⁰ IHS midstream database

⁶¹ <http://www.trend.az/capital/energy/2171188.html>

⁶² Excluding re-injected and flared gas.

oscillated around 94%⁶³. By international standard this is a relatively high utilization rate, but the total volume of flaring is still large reflecting the high production oil and gas produced at ACG.

Figure 15: Flaring of associated gas and gas utilization rate at the ACG bloc and the Sangachal terminal (ST)



Source: BP in Azerbaijan Sustainability Report

SOCAR operates a number of fields that have had considerable venting of associated gas, the most important being Shallow Water Guneshli, Neft Dashliari and Palchiiq Pilpiassi. Total venting from SOCAR operated fields was 0.5 BCM in 2007 but has since been radically reduced (see below).

2.4.2 Regulations and policies

The Ministry of Industry and Energy is the governmental body in charge of policies and regulations for the energy sector, and the Ministry of Ecology and Natural Resources is in charge of regulating environmental protection and the use of natural resources. SOCAR exercises considerable influence on gas regulatory and policy matters in practice.

A number of laws have clauses relevant to gas flaring. These notably include the Law on Environmental Protection; the Law on the Use of Energy Resources; the Law on Ecological Safety; and the Law on Air Protection. However, this legal basis is not supported by secondary legislation, such as specific requirements, allowances or penalties for pollutants applicable to gas flaring and venting. As a result, these laws have limited impacts on venting and flaring practises. For example, although the legislation stipulates the application of penalties, it does not provide any mechanisms for its implementation in the case of case flaring or venting.

In practise, the Production Sharing Agreements (PSAs) are the most important documents governing associated gas use and flaring. The PSA for ACG partners stated that SOCAR shall take delivery of the associated gas and that flaring is only allowed if SOCAR is unable to take such delivery or in cases of emergencies, equipment failures, repairs or maintenance of any facilities, including delivery systems.

⁶³ With re-injection being accounted for as gas utilization.

Under most PSA agreements, operators can use produced associate gas for their own use, but should deliver the remaining part to SOCAR free of charge. They are not allowed to export or sell associated gas domestically, which will tend to reduce the economic incentives to gather the gas.

In terms of reporting requirements, each company must report the volume of vented and flared associated gas to the relevant statistics organization. While the PSA partners prepare their reports according to contractual requirements, SOCAR's subsidiaries use their own internal formats.

2.4.3 Investments and barriers

APG utilization is already relatively high in Azerbaijan by international standards. Challenges for further flaring reductions include the fact that the volume of each source is generally low to very low and that some fields currently venting are old oil deposits with declining production, reducing the incentives to develop gas utilization plans. Moreover, economic conditions with relatively low market value for gas and weak economic incentives in the PSAs, are not very conducive of additional efforts in reduced flaring and venting.

Azerigaz (a SOCAR subsidiary) is in charge of gas transportation, distribution and storage for the domestic market. There is no wholesale gas market, and no indication that the current gas market structure is likely to change. The domestic transport tariff is regulated and set by the Tariff Council under the Ministry of Economic Development. Internal [end-user] gas tariffs have been revised four times in the last decade and may be raised again. SOCAR purchases gas from Shah Deniz Consortium at average price of 58 USD/1,000 m³ (including transportation), based on specific formula that changes periodically. Azerenerji owns most of the country's power plants (over 6,300 MW), including 11 gas-fired thermal plants. The electricity price is indirectly subsidized through a special gas tariff for power generation facilities.

Given the progress already made and barriers for investments in APG utilization further improvements will inevitably be more modest and costly than what has been achieved over the past 5-6 years. Nevertheless, both SOCAR and BP appear to have ambitious plans for further reductions in wastage of APG.

BP as operator of the ACG fields have analysed the causes of continued flaring and grouped them into four main categories:

- i) The gas injection plant being off-line or with reduced capacity
- ii) Technical problems with the flash gas compressors
- iii) Down-time of the gas facilities at ACG, and
- iv) Continuous flaring from pilot lights, purge gas and degassing of produced water.

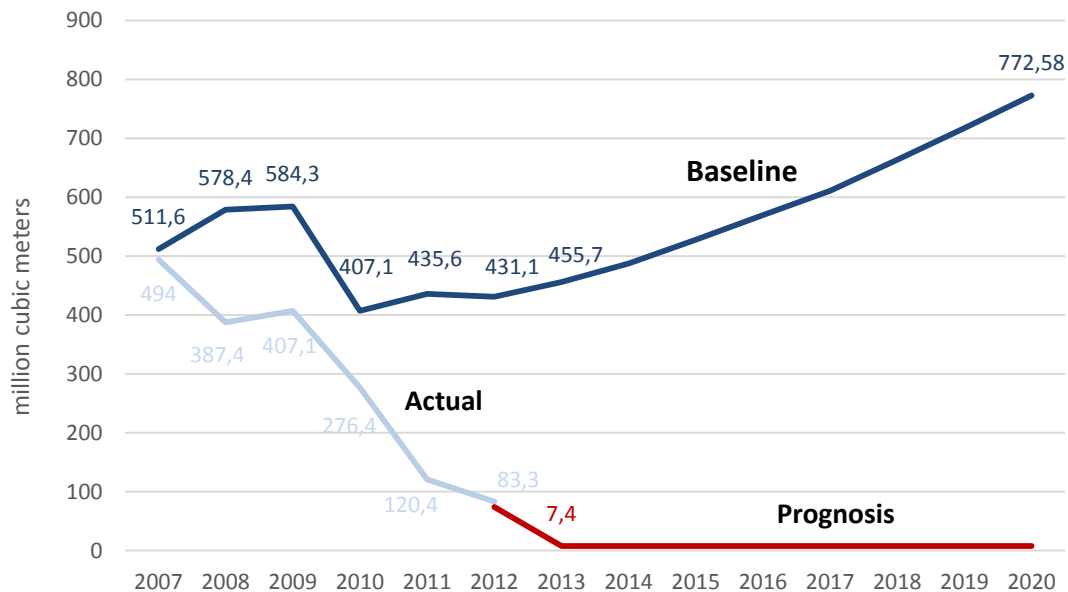
The three first categories, being intermittent flaring, account for $\frac{3}{4}$ of the total. They can be reduced through technical measures to reduce regularity of equipment. According to BP⁶⁴, a number investments have been made since 2009 to improve the reliability of existing equipment, resulting in flare reductions, including improvements to the gas injection system at Central Azeri field and to a compressor at Chirag.

⁶⁴ BP in Azerbaijan sustainability reports (2010 to 2012)

Focus is also on improved operational procedures and training of operators, this seemed to have resulted in further reduction in intermittence flaring. Preliminary figures for 2013 indicate a further improvement in the gas utilization rate at the ACG fields. Further reduction, or even total elimination, of the continuous (background) flaring will require investments in a Flare Gas Recovery Unit which is designed to recover and recycle the waste gas generated during normal operations. BP is considering installing such a system.

In 2010, SOCAR adopted an “Associated Gas Recovery Plan” and a “Strategy on Climate Change Impact Mitigation”. This has already resulted in large reductions from capture of previously vented APG from the “Shallow Water Guneshli” and “Neft Dashliari and Palchiiq Pilpiassi” fields, which is reflected in the steep decline in vented volumes shown in *Figure 16*. Both these projects were developed as so-called CDM⁶⁵ project activities in order to earn carbon credit revenues from their implicit reductions of greenhouse gas emissions. For various reasons both projects failed to earn carbon credits, but they are expected nevertheless to result in an estimated net emission reductions over 10 years of 6 million tons of CO₂ equivalents according to the CDM documents⁶⁶. However, the CDM methodology used on allows the vented methane to be converted to CO₂ equivalents as if it should have been flared, hence grossly underestimating the actual emission reduction impact. The real emission reduction impact of the two projects over a ten year period is about 45 million tons of CO₂ equivalents.

Figure 16: Vented APG in Azerbaijan



Source: State Oil Company of Azerbaijan Republic (SOCAR)

There are investments under planning or implementation for a number of other fields which supposedly will improve the APG utilization rate further, however these are small as compared to “Shallow Water Guneshli” and “Neft Dashliari and Palchiiq Pilpiassi”. Some of the fields are offshore and some onshore.

⁶⁵ Clean Development Mechanism of the Kyoto Protocol

⁶⁶ Documentation of the projects are given in so-called Project Design Documents (PDDs) placed on www.unfccc.int

In addition to producing fields Azerbaijan has more than 20,000 abandoned wells, of which some leak substantial volumes of methane. They represent an importance source of greenhouse gas emissions and SOCAR is in the process of creating an inventory of air emissions from the wells. In 2012 more than 500 measurements of well leakages were performed and efforts are on-going to improve the understanding of the scale of the problems and approaches that can be applied to reduce leakages.

Oil production in Azerbaijan is not expected to increase much from the current level but where will be fields coming on stream to compensate for the decline from ACG and other existing oil fields and this will require new investments in APG utilization.

Gas production made leap already in 2005 with start of production of Shan Deniz. This field will also be the major source of further production increased. SOCAR forecasts gas production reach 50-55 BCM/year by 2025, while the IEA forecasts peak production at 43 BCM per.⁶⁷ Expansion of gas supplies also means that the gas supply infrastructure within Azerbaijan is being further developed, including expanding the processing capacity of the Sangachal Terminal and Garadang processing plant. This would facilitate market outlets from whatever might be left of stranded associated gas.

⁶⁷ SOCAR and IEA World Energy Outlook 2010

3. Economic viability of APG utilization options

To increase utilization of APG, operational practices can be optimized and new infrastructure can be established to recover otherwise flared gas for productive use. Given the context of this study, where the focus has been to identify bankable investment projects, the objective of this chapter is to describe the economic viability of investments in infrastructure to recover and utilize APG to reduce continuous production flaring within the four target countries.

For each site where APG is flared, a number of alternative value chains may be established to recover and utilize part of the gas. The economic viability of each of these APG utilization options is affected by a large number of factors, e.g. gas characteristics, location and presence of existing infrastructure, market conditions, etc. The optimal solution for a particular site is thus highly case specific. This chapter aims at providing a high-level presentation of alternative APG utilization options that may be suitable for flare sites within the four target countries, including technical components and their pros and cons.

This chapter is organized in four main sections. The characteristics of flared gas are presented in **Section 3.1**, as these characteristics (volume, pressure and composition) have a significant impact on suitability of different gas utilization options and on the economic viability of gas utilization. **Section 3.2** contains short descriptions of different technical components which can be combined into solutions to reduce APG flaring under the following headings:

- (i) **APG gathering systems:** Technologies to collect, gather and compress different gas streams
- (ii) **Gas treatment and processing:** Key components of gas treatment and processing facilities
- (iii) **On-site use:** Gas injection, electricity and heat generation
- (iv) **Conversion processes:** Conversion of (fractions of) APG into e.g. electricity and liquid fuels
- (v) **Transport options:** Transport modes for APG and products that can be produced thereof

APG gathering systems and facilities for gas treatment and/or processing are presented first, as these value chain components are required for many different APG utilization options. Different options for productive utilization of gas on-site and off-site are then described, including possible conversions into other products and options for transportation to relevant markets.

The different technical components can be combined together to form a multitude of gas utilization options. The economic viability of investments in four “generic” APG utilization options are discussed in **Section 3.3**. The selected options do not necessarily represent the most interesting options for any given site, but are representative of solutions applied or considered in order to reduce APG flaring within the four target countries. Cost estimates used for the assessments of economic viability of the “generic” utilization options are primarily derived from QUE\$TOR⁶⁸, but estimates of costs and benefits provided through the case studies conducted as part of this Study have also been considered where relevant.

⁶⁸ QUE\$TOR is a cost-estimation software provided by IHS. This chapter includes content supplied by IHS Global SA: copyright © IHS 2011. All right reserved

Section 3.4 attempts to summarize the influence of key factors on the economic viability of key options for APG utilization, e.g. the amount of recoverable APG (supply profile), gas composition and pressure, distance to relevant markets and existing infrastructure, demand for energy on site or in close proximity of the flaring site and relevant net-back values of APG and products that can be produced thereof.

3.1 Characteristics of flared gas

Flare gas streams can have largely different characteristics in terms of gas qualities and recoverable gas quantities within the typical operational lifetime of new infrastructure established to productively utilize the gas. As this can have major implications on the product yields, production costs and achievable net-back prices, the economic attractiveness of APG utilization projects is largely dependent on the flare gas characteristics. It should be noted that the assessments presented in this report do not take into account all potential site specific variations in flare gas characteristics.

This study is focused on recovery and utilization of APG, which is gas that is associated with oil in the reservoir. Theoretically the definition could include the gas cap (i.e. gas residing above oil in a reservoir), but the term usually refers to gas dissolved within the oil (also referred to as solution gas). The amount and composition of APG vary depending on the nature of the reservoir, the type of lift that is used, the degree of depletion of the reservoir and other factors.

As the oil is brought to the surface, APG comes out of solution and is usually separated out before the oil enters the transport pipeline. Typically the gas is separated from oil in a two-phase separation, or a three-phase separation of oil and water using the density differences in the fluids. Multiple stage separation (up to four) may also be required where the produced fluid is under high-pressure and has high gas-oil ratio (GOR). The first stage separation is at a pressure less than the well pressure (which varies greatly between fields). The dissolved gases flash to form a free gas which is still at elevated pressure and can be either flared, used or sold. The remaining oil is transported to the second stage of separation which is at a lower pressure, and the resulting flashed gas will thus also be at a lower pressure than at the first stage. A third stage separation might be needed for very high GOR well streams. The final stage of separation occurs in the stock tank which is at atmospheric pressure. Gas continues to evolve and is usually vented, but may be captured, compressed and either flared, used or sold.

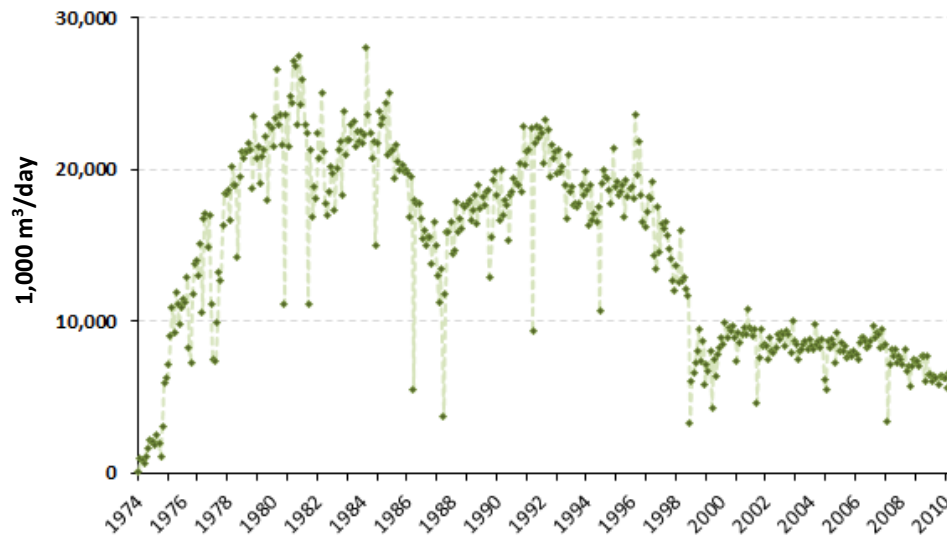
Different APG streams can have large variations in gas composition and impurities, and thus may require different levels of treatment. The variation in composition also means that different APG streams will provide different product yields and thus different economic values, even when applying the same technological solutions. Some gas utilization options, such as processing into dry gas, LPG or natural gasoline, have better returns when the recoverable gas stream is “rich”, i.e., when it contains a large portion of heavier hydrocarbons. Other options for APG use, such as large-scale electricity generation, generally work better when the gas is “lean”. An APG stream will always be more attractive when it contains fewer impurities⁶⁹ and is at an elevated pressure, due to reduced costs required for treatment and compression.

⁶⁹ In particular CO₂ and H₂S

The APG composition is not stable, but tends to vary over time as a result of multiple factors, including well depletion and changes in well stocks, recovery techniques and operating conditions. Future changes in APG compositions are difficult to predict accurately, making it more challenging to design facilities for APG than for natural gas.

APG quantities also tend to vary over time, making it difficult to ensure the optimum utilization of infrastructure. The variation in quantity over time could also have a negative effect on the negotiable price for products produced from APG if a customer has a preference for volume certainty, e.g., in the case of using APG for electricity generation. APG production and recovery rates feature short-term fluctuations due to operational changes, as well as longer-term variations due to changes in GORs, depletion of hydrocarbon reservoirs, changes in recovery techniques, the drilling of new wells and the shutting in of old wells, among other causes.

Figure 17: Long-term development in APG production at an actual oil field (1,000 m³/day)



Source: Norwegian Petroleum Directorate

3.2 Technology components of APG utilization options

Technical components that can be used to establish value chains for APG are briefly presented below.

3.2.1 APG gathering systems

APG is usually separated from the oil using a number of consecutive pressure vessels, resulting in multiple APG streams with different characteristics. When multiple APG streams are to be recovered, a system to gather them into a comingled stream is often required prior to further handling. The technical design of the gas gathering system will depend on the characteristics and locations of these APG streams, the desired delivery conditions and the location of the common infrastructure to which they will be delivered for further processing or use.

The APG gathering system typically consists of gas pipelines, dehydration and compression facilities to allow comingling⁷⁰. The gas gathering system normally consists of relatively low-diameter gas pipelines to transport gas at limited pressure (<10 BarG). Pipelines can be made of steel or highly advanced plastic depending on operating conditions. In addition to material and diameter, key cost drivers for gas pipelines include the winterization of the pipeline and the terrain. Insulation of the pipeline, for example, can increase CAPEX by more than 60%, while terrain factors can lead to a doubling of CAPEX. Costs can also double if the gas is acidic and thus requires transport in pipes made of stainless steel or duplex.

In some cases it is favourable to transport gas comingled with oil to central processing facilities for separation and recovery, e.g. in situations where there is a lack of compression facilities upstream. This transport option is sometimes used to recover low-pressure gases from multiple sites, avoiding the cost of small-scale distributed compressor units.

At a delivery pressure of 10 BarG at the outlet of a gas gathering system, the unit cost of APG recovery can range from less than USD 5 per million cubic meter for partial recovery of high-pressure APG streams requiring short distance pipeline transport to downstream facilities, to over USD 200 per million cubic meter for complete recovery of very low-pressure gas streams and longer pipeline connections. As a result, the desired recovery level is often optimized based on differences in unit recovery costs and gas qualities.

3.2.2 Gas treatment and processing

APG will generally require treatment if it is to be utilized productively. The main gas treatment processes are compression, dehydration, chilling, fractionation, liquefaction, desulphurization, and CO₂-removal. While gas treatment processes can be applied at various points along the gas value chain to increase transportability, remove impurities and separate the APG stream into useful products (including intermediary ones), these processes are often combined in a single facility; a gas processing plant (GPP⁷¹). One of the most common ways to utilize APG within the four target countries is to gather it upstream and supply it to large, centralized gas processing plants (GPPs) to produce dry stripped gas (DSG), LPG (propane-butane mix) and natural gasoline (SNG).

Compression

Gas compression can be required to facilitate transportation and/or comingling of different raw APG streams in a gas gathering system. It is also usually required to bring the recovered gas to a sufficiently high pressure to be treated and/or used productively. A gas compression station typically consists of liquid and particulate removal devices such as “scrubbers”, a number of compressor units, necessary auxiliary systems and facilities, and process metering systems. In order to bring the gas to the desired pressure, it

⁷⁰ The gathering system may or may not include basic treatment of APG streams prior to transportation and/or comingling, e.g. dehydration and compression. The relevant APG treatment technologies are further described in **Section 3.2.2**, as they may be applied at multiple stages of a full APG value chain.

⁷¹ GPPs typically consist of equipment for compression, dehydration, sweetening (if required), NGL extraction, fractionation and marketing of products, including storage and loading facilities for liquids. It also requires control systems, metering arrangements and utilities.

is passed through one or multiple stages of compression. Unit compression costs of gas vary depending on the suction and discharge pressure, gas flow rate, energy costs and the yield and value of drop-out liquids. While the cost/net-back value of electricity/fuel gas varies between sites, the total, annual OPEX related to compression typically amount to 6-7% of CAPEX for compression ratios ~10.

At lower suction pressures, the compression ratio is high and the energy required to reach the desired discharge pressure is similarly high. Unit compression costs could be prohibitive for very low pressure APG streams, essentially preventing economic recovery as part of a flare gas utilization project. This is one of the reasons why second-stage (low-pressure) separation gas has been flared at many sites within the four target countries, while first-stage separation gas has been (partly) recovered and utilized productively.

When constructing a gathering network for APG streams with different pressure levels, there is often a trade-off between distributed and centralized compression facilities. In most cases where multiple gas streams are gathered in the same system, a combination of distributed and centralized compression will provide optimum economic results.

Dehydration

In most cases, gas must be dehydrated if it is to be transported in a pipeline. Dehydration is conducted to prevent moisture in hydrocarbons from contaminating pipes and vessels downstream. Water can be absorbed by passing the gas through a glycol/water solution in a separator, absorbed by a desiccant, separated by electrical coalescence, or boiled off. The CAPEX related to dehydration is usually relatively small.

Sweetening (desulphurization and CO₂ removal)

If gas is “sour”, i.e. contains significant amounts of hydrogen sulphide (H₂S), it usually must be treated to remove the H₂S before it is used or marketed. This is due to the toxicity of the gas and the corrosive nature of the sulphur oxides that result from its burning. The most common processes for H₂S removal are the amine absorption process, the molecular sieve process and the iron-sponge process. The cost of desulphurization is heavily dependent upon the H₂S concentration.

If the gas contains significant amounts of CO₂, which is acidic, this often needs to be removed in order to increase the heating value and to prevent corrosion of the pipelines and gas processing equipment. The selection of a CO₂ removal process is often based on gas composition and operating conditions.

HC dew point control and/or NGL extraction

Rich APG streams can contain significant amounts of heavy hydrocarbons, which will condense at elevated pressure as the gas cools, e.g. during pipeline transportation. The presence of heavy hydrocarbons can represent significant added value if they are extracted from the raw gas stream and marketed separately. It is often desirable to split the gas into a lean gas mixture with a controlled hydrocarbon (HC) dew point, such as “dry stripped gas” (DSG), and a hydrocarbon mix consisting of natural gas liquids (NGLs). This can be achieved through one of the following processes: absorption, modified absorption, or cryogenic expansion. The optimal process design will depend on whether the goal is to produce lean gas complying with specific quality requirements, maximize NGL (and ethane) extraction, or both.

The lean gas resulting from extracting heavier hydrocarbons can be treated further (e.g., compressed) before being marketed, utilized on site or used as fuel and/or feedstock to produce other marketable products. The CAPEX required for dew point control represents a small portion of the overall costs related to gas processing, and the per-unit cost drops significantly with volume.

Fractionation

A number of valuable products can be produced from the liquid part of the APG, which condense as a result of HC dew point control and NGL extraction. Depending on the desired product specifications, a number of fractionation towers/columns (typically 2-3) can be used to separate the inlet stream into individual products for separate marketing or use, typically consisting of ethane, LPG and stable gas condensate.

Liquefaction

In order to improve the transportability of natural gas, it can be condensed into Liquefied Natural Gas (LNG), which takes up about 1/600th the volume of natural gas in its gaseous state. Following initial APG treatment to remove water, H₂S, CO₂, heavier hydrocarbons and other components that might freeze (often referred to as “purification” in the context of LNG production), the resultant dry gas can be fed to a gas liquefaction unit (LNG train). In the LNG train, the gas is cooled down in stages until it is liquefied (at approximately -162 °C). The LNG is then routed to storage tanks from where it can be periodically loaded and shipped using suitable vessels or tanks.

Section 3.3 presents the attractiveness of four types of investment cases to improve APG utilization, including a case comprising construction of a GPP.

3.2.3 On-site use

The share of produced APG which is used productively on-site will vary from field to field, essentially from 0% to 100%. The amount of excess gas on-site can be reduced by re-injection and additional electricity and heat generation. Re-injection may eliminate all flaring on-site, while the last two gas options normally will only offer a part solution due to limited demand for heat and power locally.

Re-injection

Flaring of APG typically occurs where natural gas has a limited value due to lack of access to wider gas grids. In some cases, APG (after stripping useful liquids) could be re-injected into the producing reservoir to increase production, or alternatively into a geological formation for temporary or permanent storage. Re-injection of gas typically requires significant compression, which in turn implies substantial investments, especially at brownfield sites.

APG is often flared rather than re-injected into producing reservoirs if there are limited economic benefits associated with re-injection for improved oil recovery at a particular field. However, flaring instead of re-injection can also be due to lack of knowledge about the optimization of producing reservoirs. On the other hand, some reservoirs are not considered suitable for re-injection due to potential problems of gas break-through that could affect oil production – the primary source of revenues. The benefits of re-

injection for enhanced oil recovery will depend on a number of technical factors that must be assessed through a detailed reservoir model.

Both depleted reservoirs and producing reservoirs can be appropriate for gas storage, as can other formations such as salt caverns. The economic incentives related to re-injection for storage is limited to the value of preserving the resource for potential use in the future (e.g. for use in power generation) and any cost savings or reduced risks related to flaring avoidance. Since prospects for development of attractive gas markets within the investment horizon of private companies could be low in many regions, investments in re-injection for storage normally will only make sense in the face of high penalties for flaring or other similarly strict regulations.

Onshore, well construction costs vary greatly depending on a number of factors, including target depth, well profile and geological formation types.

Electricity and heat generation for local use

APG can be used as fuel to produce electricity for meeting local demand and/or supplying the grid. The optimal generation technology and power plant design will depend on many factors, including fuel gas quantity, quality and reliability of supply, electricity demand, load curve and desired fuel flexibility.

When considering APG for on-site power generation, it is critical to consider all variables that affect stability and reliability of power supply, such as crude oil production, water cut, GOR and gas quality and quantity. These variables are neither fully predictable nor stable, posing significant challenges to using APG in an industry where reliability of electricity supply is of vital importance. Back-up fuel supplies and/or generation capacity is vital, either in the form of additional (non-associated) gas supplies, a grid connection or installation of dual-fuel generation units. Changing the operational practices of an oil company to endorse a gas-to-power project can also be challenging, due to unconventional capital expenditure requirements, potential loss of crude oil production during project implementation and significant technical and operational barriers that need to be overcome for continuous use of associated gas.

Gas-fired generation technologies include gas engines, gas turbine generators, and steam turbine generators. Depending on which solution is applied, the APG may require treatment and processing (conditioning) prior to use as a fuel.

The prefabrication, construction and material costs of small-scale power plants are highly variable and depend on local conditions. The total CAPEX for small-scale power generation based on APG is estimated to be in the range of 1.1 to 3.0 million USD per MW⁷² of installed capacity, including back-up power supply, local grid connections, plant utilities and control system. In Russia, there are a couple of recent examples of large-scale power plants using primarily (treated) APG as fuel. Rosneft has e.g. constructed a 345 MW captive power plant to supply electricity for oilfield operations at the giant Priobskoye field.

⁷² JI PDDs in Russia and literature review.

If there is a demand for heat in close proximity to suitable power plant locations, combined heat and power (CHP) technologies can be used to produce both electricity and heat. For a combined production of heat and power at a larger plant, energy efficiencies approaching 90% can be reached.

APG potentially can be used to produce heat for on-site oil treatment or (after transportation) as a fuel to produce heat for industrial consumers or population centers, potentially replacing other costly fuel sources. As long as APG transportation is not compromised, gas quality requirements for use of APG as a fuel in boilers are less stringent than those for supplying gas transmission and distribution systems. In some situations, it could thus be commercially viable to directly supply existing heat generation facilities with APG fuel gas.

3.2.4 Using APG fractions as fuel or feedstock

A number of technologies are available to convert APG fractions resulting from gas treatment and/or processing into potentially more valuable products, such as electricity, heat, petrochemicals and liquid fuels, as well as various energy-intensive industrial products such as fertilizer and steel. A full overview of all available options to utilize APG fractions as fuel or feedstock is not included here. Due to the main objective of this study (i.e. identification of bankable investment projects in collaboration with potential clients), the options of using (treated) APG for electricity generation and Gas-to-Liquids (GTL) have been studied in more detail and are presented below.

Electricity generation for grid export

In many oil fields, the electricity demand is significantly lower than the amount of electricity that can be generated by the APG. This implies that using the APG to generate electricity to meet the needs of the oil field usually will only represent a partial solution in terms of flare avoidance. Electricity generation can also be considered in larger scale to export the electricity to the regional or national markets.

A large-scale power plant may consume up to 1 BCM/year of gas. Due to significant capital expenditures, ensuring optimal capacity utilization is the key to economic attractiveness. As a result, medium to large-scale power plants would only be attractive in cases where sufficient volumes of APG could be aggregated to provide the power plant with a reliable supply of fuel over time. The costs associated with establishing gas gathering infrastructure and gas treatment and processing facilities to supply a large-scale power plant can be substantial. This implies that the cost of electricity generation based on APG will only be lower than electricity generation based on gas purchased at domestic prices under special circumstances, e.g., when there are shortages of generation capacity or a limited ability to export/sell treated gas.

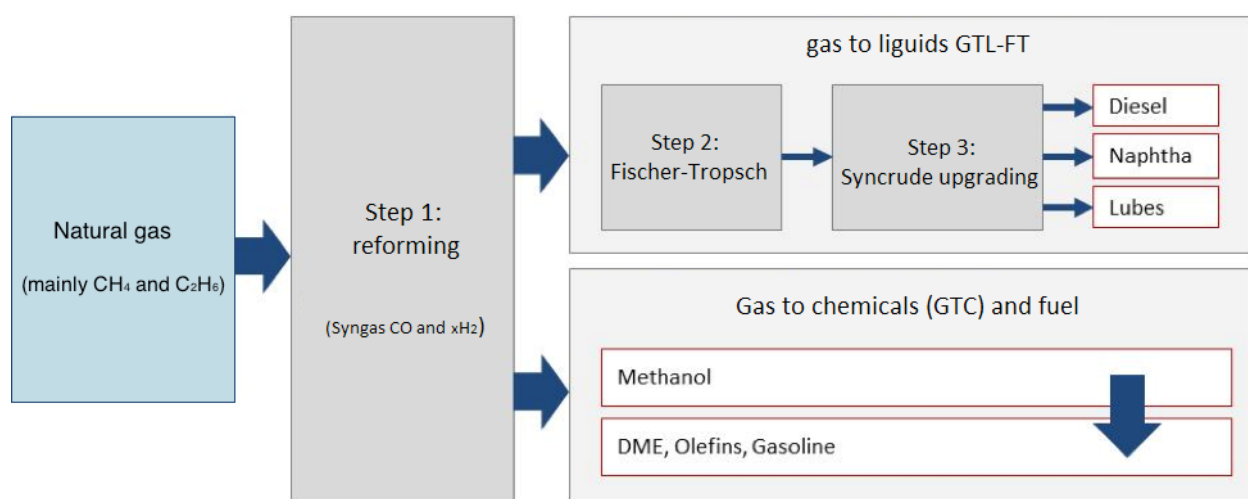
Gas to liquids

Gas-to-Liquids⁷³ (GTL) is a term typically used to describe the conversion of natural gas into liquid fuels (predominantly synthetic diesel) via the traditional “Fischer-Tropsch” route. However, the largest and oldest gas-to-liquid technology is production of methanol⁷⁴.

Gas conversion to liquid fuels and chemicals is a capital intensive industry, where economy of scale has been critical. World scale methanol plants consume ~1.5 BCM of natural gas per year, while GTL Fischer-Tropsch (FT) plants have a capacity exceeding 35,000 bbl/day liquid fuel production (consuming >3.5 BCM/year).

Typical reaction routes and product outputs for common GTL technologies are illustrated in *Figure 18*.

Figure 18: Typical reaction routes for GTL technologies



Source: Carbon Limits

The 1st reaction step (reforming), the manufacture of “syngas” or synthesis gas, is common to all the reaction routes shown in *Figure 18*. The 2nd reaction step (i.e. the Fischer-Tropsch (FT) step), is common for solutions that produce syncrude or refined fuels, and involves a series of chemical reactions that produce a variety of long-chained hydrocarbons. GTL plants comprising only the reforming and FT steps yield syncrude, which can be marketed with crude oil (potentially following simple hydrocracking if needed to meet specs). A hydrocracking unit can be installed to upgraded syncrude to diesel, naphtha or lubes (3rd step shown in *Figure 18*). This step can be achieved using a range of conventional technologies, and could yield products that sometimes can be marketed locally at a premium.

Methanol production provides an alternative to the 2 to 3 step FT reaction routes. Manufacturing of methanol is the oldest and largest gas-to-liquids technology, and there are a large number of operating

⁷³ Many acronyms are being used; from GTL and GTC to gas-to-fuels (GTF) and gas-to-gasoline (GTG). For simplicity, the most common term “GTL” will be used for all options covered in this report.

⁷⁴ This branch of gas conversion is often referred to as “Gas-to-Chemicals” (GTC), since the major use of methanol has been as a feedstock for other chemicals. Increasing shares of methanol however end up in liquid transportation fuels such as MTBE, bio-diesel and DME (dimethyl ether). It has been predicted that within five years, more than half of the methanol supply will end up as a liquid energy carrier, eclipsing its use as a chemical.

plants worldwide. Some novel technologies to convert gas to methanol and other products are also under development. Methanol can be further converted to e.g. DME⁷⁵ or gasoline for potential use as liquid energy carrier/transport fuel.

In general, there are little differences in the feed gas requirements between technologies; all technologies can use DSG as feedstock, while higher carbon content gases can be accommodated with minor modifications if gas fractionation is not feasible⁷⁶. All technologies are sensitive to poisons, and sulphur and mercury must be removed. Nitrogen and carbon dioxide are diluents and can be tolerated in moderate concentrations. Due to GTL being a capital intensive option for monetization of gas, achieving high capacity utilization is key to economic efficiency (i.e. having stable, long-term gas supplies or a modular solution with good turn-down ratio). Higher pressure is generally an advantage since the 1st step reformers of most FT reaction routes run at elevated pressures (> 20 bar).

GTL plants are relatively complex facilities, and transportability of equipment and site accessibility is generally an important determinant for overall plant costs. This is particularly important in remote locations. Harsh climate conditions can also provide a challenge that must be addressed in terms of site access, construction/assembly and plant design (e.g. need for insulation, merits of water cooling, etc.).

So far there is no modern GTL synthetic motor fuels production on an industrial scale in the four target countries. A number of companies are developing solutions suitable for smaller plants using innovative technologies. With new approaches, the challenges typically posed by using APG as feedstock can be overcome (e.g. limited and changing supply over time).

Other products

After treatment, APG could in theory be used as feedstock and/or fuel for production of fertilizers such as ammonia and urea, or in the production of energy-intensive products such as steel. In practice, such conversion is not commonly part of solutions adopted to reduce gas flaring, since the disadvantages of relying on a variable source of fuel/feedstock supply and the importance of access to raw materials and low-cost transportation options to relevant markets tend to be greater than the advantage of a relatively cheap source of feedstock or fuel. A minimum reliability of gas supplies is required to ensure optimal capacity utilization of new infrastructure, either in the form of aggregation of multiple APG supply sources or through use of a combination of APG and a manageable backup supply of natural gas.

3.2.5 Transport options

APG can yield a large number of potential products, such as natural gas, LPG, stabilized gas condensate and electricity, all of which would need further transportation to market. Transportation opportunities and costs are key for the economic viability of investments in establishing APG value chains.

⁷⁵ DME has physical properties similar to LPG, and can be a direct replacement of LPG (blended up to 100% in LPG) and use existing LPG infrastructure.

⁷⁶ Economically it normally makes less sense to convert C₃₊ to syngas rather than separating it out as LPG/condensate.

Natural gas

To facilitate cost-effective movement of natural gas, a suitable gas transportation system is required. Natural gas at atmospheric pressure has a very low energy density and is difficult to store and transport.

Table 4: Options for taking recovered gas to market

Aspect	Pipelines	CNG	LNG
Energy density ⁷⁷	● ~<100x	● ~200x	● ~600x
Storage	● Difficult	● Limited	● Cryogenic
Transport	● Short-Medium	● Short	● Medium-Long
Energy losses	● 2-5%	● 5-10%	● 15-25%
Fuel flexibility	● Low	● High	● Medium
Capital costs	● Med-high	● Low	● High
Operating costs	● Low	● Relatively high	● Medium
Volume scale	Any range	Small	Medium-Large

Source: SCC Mena

Options to address this problem include treatment of the APG into pressurized gas, CNG and LNG to facilitate transport and storage. Table 4 gives a high-level overview of the different transport options.

Gas pipelines would normally provide the most economic transport option within the four target countries, in particular for fields relatively close to existing infrastructure. However, capacity and access to existing gas pipelines can be constrained in some regions. Increasing the capacity/extension of the gas transmission network could facilitate increased APG utilization in some regions, but investment in large-diameter transmission pipelines for long-distance transportation is typically not undertaken by upstream producers flaring gas. The situation is particularly challenging for operators of small and medium sized fields in remote locations. In some cases, there could be strong economic rationale for coordinating investments to address flaring at multiple sites through “clustering” solutions, e.g. to provide resource base to justify new gas trunklines.

LPG transport

LPG produced as a result of gas fractionation in a gas processing plant (GPP) can be stored on site in tanks and transported by truck, rail or ship. A significant fleet of vehicles may be required for large LPG quantities and/or long distances, resulting in complex logistical operations and high investment costs. From a rail terminal, LPG containers or tanks can be loaded and transported to a designated market. A new rail terminal or an upgrade of existing infrastructure is often required to handle the liquids, potentially representing a significant investment. Once loaded, transport costs are dependent upon tariffs, usually a function of transport distance and route complexity. In the marine transportation market,

⁷⁷ Compared to natural gas at atmospheric pressure

LPG is typically transported by dedicated vessels suitable for carrying pressurized, semi-pressurized or refrigerated LPG.

Transport of stabilized gas condensate (natural gasoline)

Stabilized gas condensate can be transported via existing oil pipelines, dedicated pipelines, trucks or rail. Its road or railway transport has a similar cost structure to that of LPG. NGLs recovered upstream are often injected into an oil stream for export. “Spiking” the oil in this way increases its API gravity, potentially increasing the oil’s net-back value per barrel, while also increasing its volume. If flow regimes and product specifications are not compromised, hydrocarbon liquids from gas processing can be transported via existing oil pipelines at limited costs.

Transport “trade-offs” and optimal location of new facilities

For many flare sites, APG utilization is facilitated by creating value chains that involve transportation of multiple intermediary and marketable products. Due to differences in transport costs for different products, new facilities and infrastructure established to productively utilize APG should be located such that the economic returns of these investments are maximized. In practice, this often implies that GPPs should be located as close to existing product markets and export infrastructure (railways or ports) as possible, relying on long-distance pipeline transportation of APG upstream.

For a gas value chain consisting of gas gathering infrastructure and a new grid-connected power plant, there is a trade-off between gas and electricity transportation costs. Generally, however, transportation costs for gas are lower less than those for electricity⁷⁸. Energy losses are also considerably lower for gas pipeline transport compared to electricity transmission. Moreover, unlike electricity, gas can be temporarily stored in pipelines as “linepack”, which tends to reduce the challenges associated with temporary fluctuations in APG recovery rates.

3.3 Attractiveness of investments in APG utilization

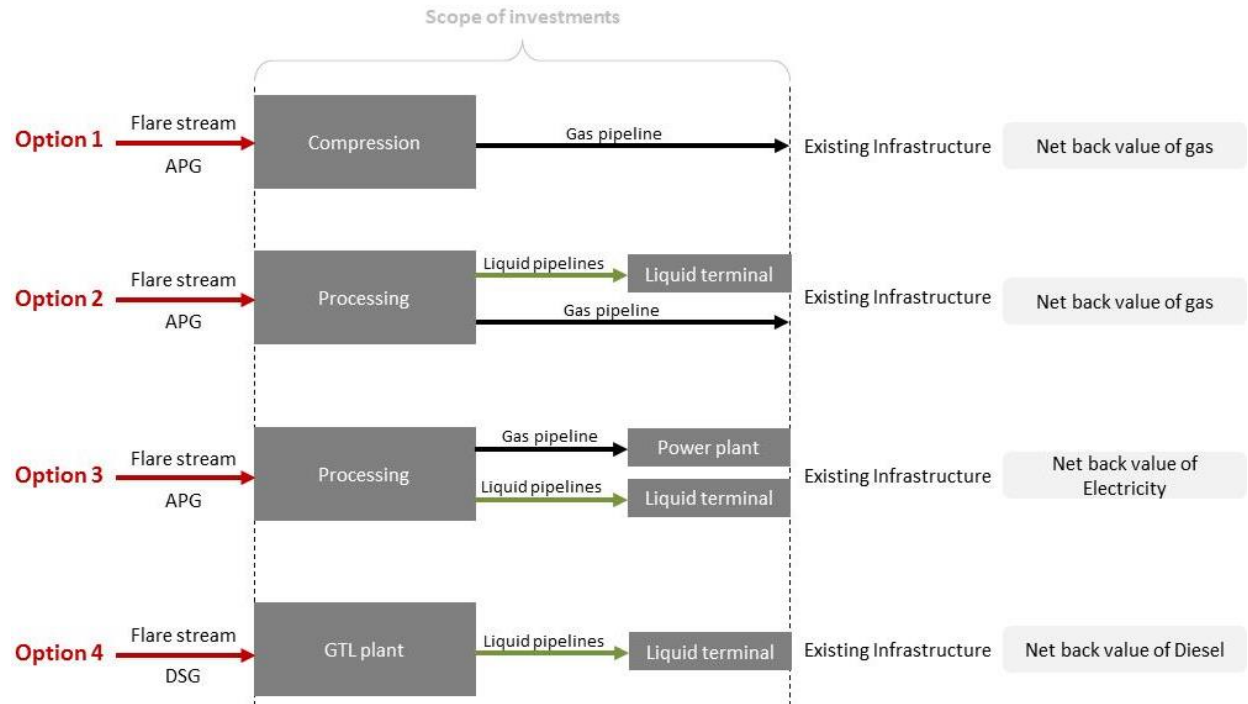
The technology components presented in the previous section can be used to create a large number of alternative value chains for APG. In reality, the realistic options for most sites where APG is flared are few. This is primarily due to the presence of existing infrastructure, the organization of the industry and the status of relevant markets for APG and products that can be produced from it.

The economic viability of investments in four “generic” APG utilization options is discussed below:

- Option 1.** Gas gathering and supply of APG to existing downstream infrastructure
- Option 2.** Gas gathering, processing and marketing of resulting DSG, LPG and natural gasoline
- Option 3.** Gas gathering, treatment and use in electricity generation for export off site
- Option 4.** GTL plant for production of diesel and naphtha

⁷⁸ http://www.northwestchptap.org/NwChpDocs/Transmission_and_N_Gas_Comparing_Pipes_and_Wires_032304.pdf

Figure 19: Overview of the four utilization options evaluated



Source: Carbon Limits analysis

These four options do not necessarily represent the most interesting options for any given flare site, but are representative of solutions applied or considered in order to reduce APG flaring within the four target countries⁷⁹. The economic attractiveness of each option has been evaluated for a range of conditions, taking into account variations in physical conditions, costs (CAPEX and OPEX) and benefits. Cost estimates used for the assessments of economic viability of the four utilization options are primarily derived from QUE\$TOR⁸⁰, but estimates of costs and benefits provided through the case studies conducted as part of this Study has also been considered where relevant.

In the following paragraphs, the economic attractiveness is expressed in terms of the required net-back value of the main product in order to provide a potential investor a minimum return on the investment, defined as 10% IRR for illustrative purposes. When calculating the net-back value of the main product, “by-products” such as LPG and natural gasoline are valued at conservative market prices⁸¹. For each option, the resulting net-back value can be compared to the relevant market value of the product in the different regions covered by this study.

⁷⁹ In remote areas, re-injection of gas is increasingly considered to be an attractive alternative to flaring. Since the attractiveness of this option depends on the reservoir where the gas is injected, however, it cannot be studied meaningfully without knowledge of site-specific geological characteristics.

⁸⁰ QUE\$TOR is a cost-estimation software provided by IHS. This chapter includes content supplied by IHS Global SA: copyright © IHS 2011. All right reserved. Cost data from QUE\$TOR were extracted Q3 2011.

⁸¹ In the base case, the LPG net-back price has been assumed at 200 USD/ton at the exit of the GPP, while the gasoline price has been set to 25 USD/bbl (base case)

The base case scenario for the assessment of economic viability is based on the following assumptions unless specified otherwise:

- For simplicity, it is assumed that one single stream of APG is recovered. The gas is recovered at 8 bars and 10 degree C, and has a liquid content of 36 barrels per million standard cubic feet and a molecular weight of 21;
- The field costs (administration and lease) are not attributed to the additional investments in APG utilization (covered by other operations);
- The well facilities are assumed to be unchanged;
- A decrease in gas volume of 2.5% per year is assumed, though short-term variations in gas recovery rates have not been taken into account;
- OPEX are fixed over time;
- No monetary value is associated with the avoidance of flaring (due to differences in the regulations between the four target countries);
- All infrastructure is assumed to be onshore.

The country overviews have highlighted the great variety of flare characteristics across the four countries; flare sizes vary from 0.001 to almost 2 BCM/year some flares are located a few kilometres away from existing infrastructure, while others are located hundreds of kilometres away, gas compositions are highly variable, etc. The results presented below thus do not provide a comprehensive overview covering all potential variations in site-specific characteristics across the four target countries.

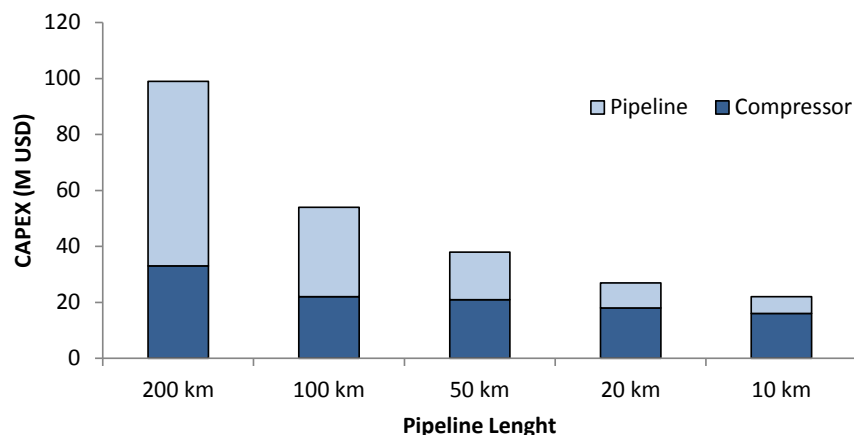
3.3.1 Option 1: Gas gathering and supply of APG to existing infrastructure

This option consists of investments in new infrastructure to gather APG to allow recovery and supply of gas to existing downstream infrastructure, such as an existing gas system with downstream processing or directly to an existing GPP or power plant. In the base case, the investments comprise a compressor station and a new gas pipeline⁸². This represents an attractive gas utilization option in regions where there is available capacity to process gas. Flare sites in the Zhanazhol area in Kazakhstan and the Khanty-Mansiysk region in Russia may be good candidates for this type of gas utilization.

Figure 20 provides an overview of the CAPEX split between compressor and pipeline costs. As pipeline length is reduced, so is the need for compression and hence required compressor CAPEX.

⁸² The economic assessment is done assuming one compressor at the point of recovery and a gas pipeline. The outlet pressure at the delivery point into existing infrastructure is set to 10 bars.

Figure 20: Split of CAPEX for Option 1 depending on the required pipeline length (0.1 BCM/year)



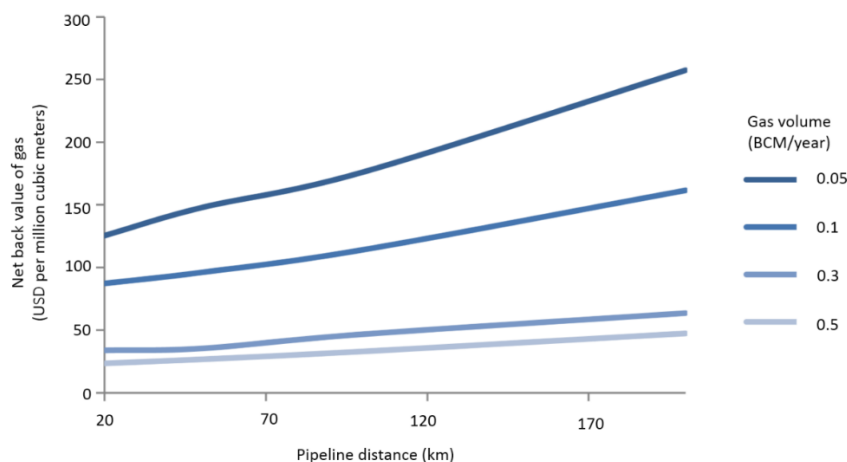
Source: CAPEX includes equipment, material, construction, insurance, design and contingency costs. Includes content supplied by IHS GLOBAL LIMITED; copyright© IHS GLOBAL LIMITED, 2011

Figure 21 shows the required net-back value of APG for this option. The assessment of economic viability confirms that gas compression and gathering is relatively expensive compared to the net-back values that can be achieved for supply of APG as feedstock to GPPs in the four target countries. These costs represent one of the key barriers to gas utilization, particularly in the case of scattered small flares.

In some cases, low-pressure pipelines can be installed to gather and supply gas without compression. The CAPEX of this solution would be much lower than the one presented above, but also leads to lower-quality product, i.e. very low-pressure APG. However, this solution can represent a more attractive solution if there is existing available compression capacity downstream.

It is important to note that hydrocarbons might drop out during compression, facilitating recovery of valuable liquids in addition to the APG that can be supplied for further processing/use. This has not been taken into account in the above economic analysis, since liquid drop-out depends on specific gas characteristics. However, this could make this type of project much more attractive.

Figure 21: Netback value of the gas depending on the pipeline length and the volume of gas transported



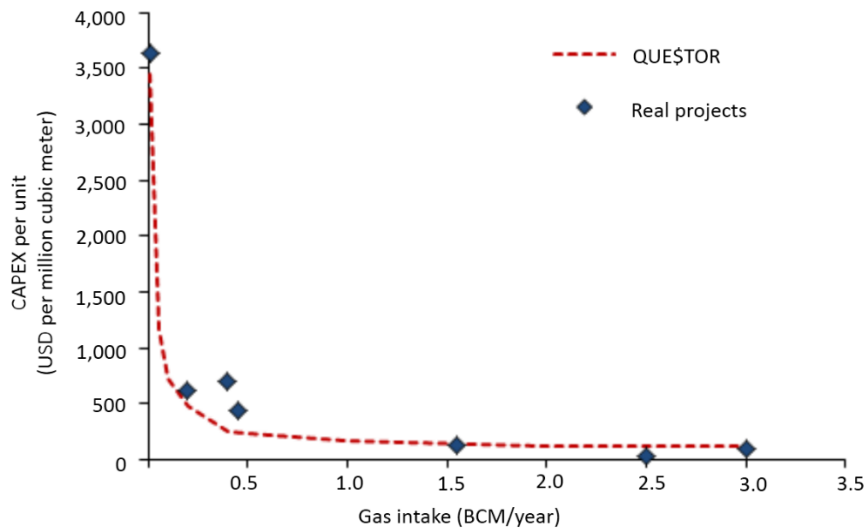
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3.3.2 Option 2: Gas gathering, GPP and marketing of processed products

This option comprise the construction of (1) new infrastructure to gather gas, (2) a new GPP for processing of APG into DSG, LPG and natural gasoline, and (3) transport infrastructure for supplying processed products to markets⁸³. This gas utilization option has been used in a number of cases within the four target countries, e.g. at the Zapadnoe Salymkoye field (~0.4 BCM of APG inlet capacity).

The total costs of a simple GPP suitable for APG processing have been estimated using QUE\$TOR and compared with the costs reported from actual project in the region (see *Figure 22*)⁸⁴.

Figure 22: Unit CAPEX for GPPs with different feed gas rates, QUE\$TOR and publicly available estimates



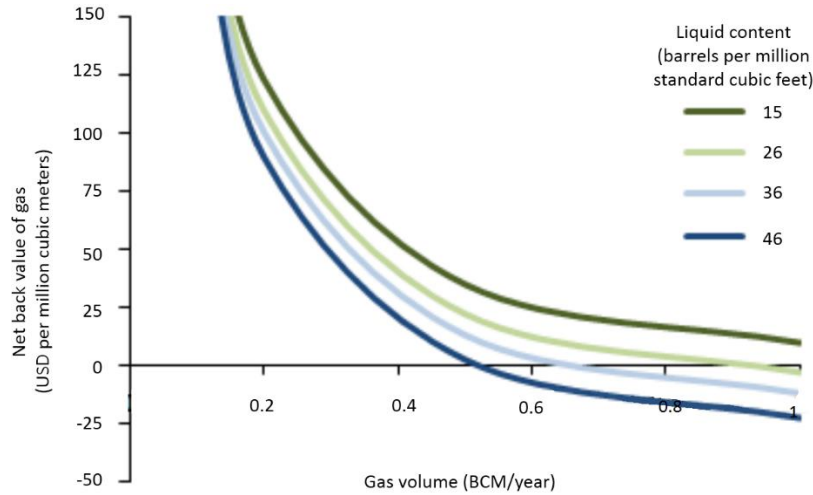
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As presented in *Figure 23*, this option requires recovery of relatively large volumes of APG to be economically attractive when assuming a net-back value of DSG of around USD 90 per million cubic meters. However, the total revenues for this gas utilization option are highly influenced by the sale of liquids (LPG and gasoline). As a result, the liquid content (C₃₊) has an important effect on the economic attractiveness.

⁸³ In the base-case scenario, the investments cover a GPP located at the flare site that includes acid gas removal, dehydration, dew point control, fractionation, stabilization, compression and power generation; a 20-km LPG pipeline, an LPG terminal, a 5-km condensate pipeline and a gas export pipeline of variable length.

⁸⁴ To review the quality of the cost estimates obtained from QUE\$TOR, CL has compared the cost estimates to the published CAPEX for a few relatively similar GPPs in Russia in Kazakhstan and confirms that the CAPEX estimates obtained from QUE\$TOR are reliable within a reasonable range of uncertainty. CL has also performed a number of sensitivities on the assumptions. These show that H₂S content can have an important effect on the total CAPEX, as can terrain conditions, e.g., particularly swampy or mountainous terrain can result in much higher CAPEX.

Figure 23: Dry gas net-back value for 0.1 BCM/year (Option 2)

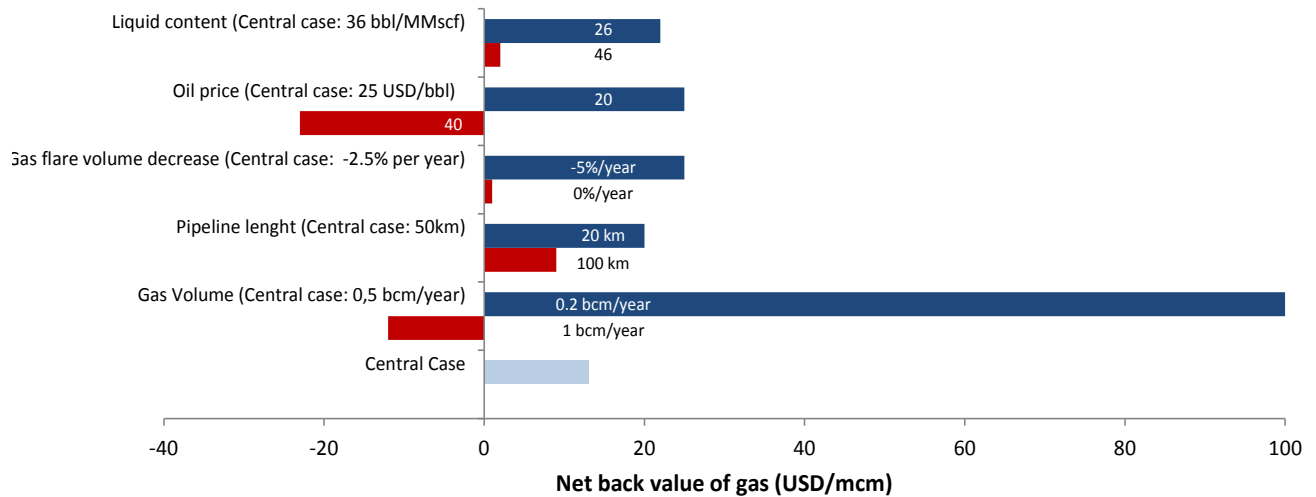


Source: Includes content supplied by IHS GLOBAL LIMITED; copyright© IHS GLOBAL LIMITED, 2011

An investment in recovery of large volumes of APG (>0.5 BCM/year) seems highly economical under the base case scenario. However, the analysis done does not take into account the costs associated with gathering of gas upstream of the GPP to secure a sufficiently large resource base from multiple smaller oil field flares, which may increase costs significantly.

Figure 24 presents the results of a sensitivity analysis for a base case comprising a 50-km pipeline for dry gas export and APG recovery of 0.5 BCM/year.

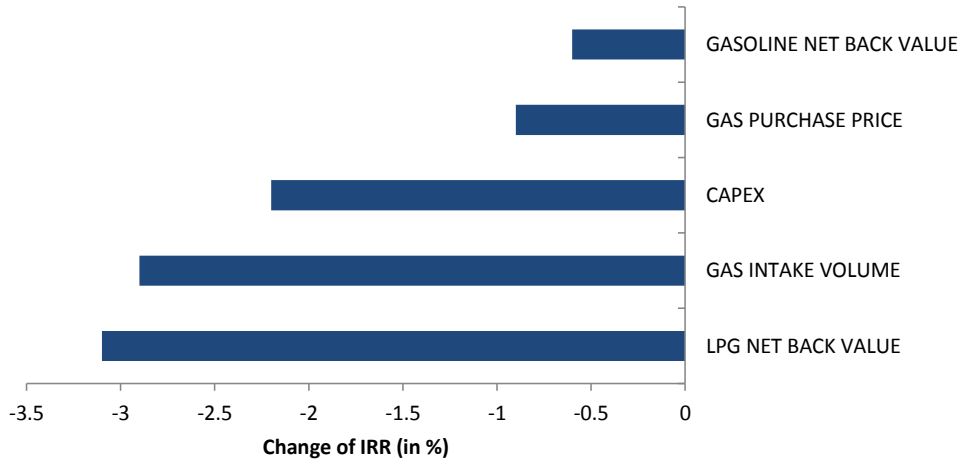
Figure 24: Sensitivity analysis (0.5 BCM/year and 50 km of gas pipeline for dry gas export)



Source: Carbon Limits analysis

The economic attractiveness of investments in new gas processing capacity is highly site specific. *Figure 25* presents the results of a sensitivity analysis performed for a small- to mid-size GPP in Russia in terms of impact on Project IRR.

Figure 25: Sensitivity analysis - impact of a 10% change of key assumptions on Project IRR (Nominal, Post-Tax)



Source: Carbon Limits analysis

This analysis shows that a 10% reduction in the expected LPG netback value has the biggest impact on the economic viability for the investment studied. A 10% decrease of the volume of gas delivered to the GPP can also reduce the Project IRR by almost 3 percentage points.

Overall, experience from a number of projects in the region has showed that the netback back value of LPG and gasoline are important factors for the project economics. It is thus crucial during the assessment of a project to understand the full LPG supply chain and review in details the difference source of CAPEX and OPEX costs.

The LPG produced at such facility could be exported both to the national and to the international markets. International LPG prices are increasingly correlated, even if large regional difference remains. As the petrochemical industry remains an important international consumer of LPG, the LPG price is closely related to the naphtha price. Russian LPG supplies from associated gas processing grow rapidly. This has now resulted in a net surplus on the domestic market, with increased competition between suppliers as a result. Purvin & Gertz have forecasted that the CIS region is long of LPG in 2014. The Europe-CIS region as a whole, however, is still net short of LPG.

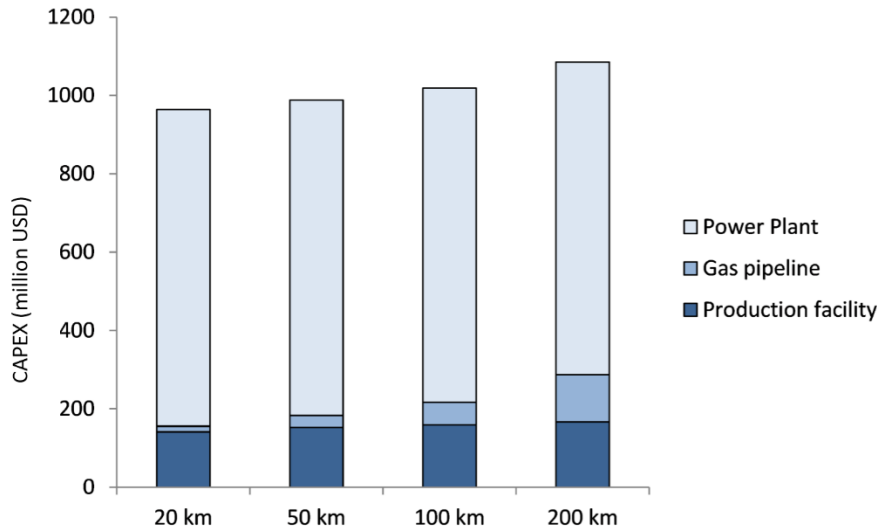
3.3.3 Option 3: Gas gathering, treatment and electricity generation

This option comprises investments in (1) new infrastructure to gather gas upstream, (2) a gas treatment unit for separation of APG into dry stripped gas and liquid hydrocarbons (NGLs), (3) a gas-fired power plant, and (4) infrastructure for supplying electricity and liquid hydrocarbons to markets. In the base case scenario, the assumed investment costs cover a gas treatment unit (including compression) located at the

flare site, a gas pipeline for export of fuel gas and a new power plant⁸⁵ located next to the grid. It is assumed that NGLs are extracted and mixed with oil for export.

Figure 26 presents the CAPEX breakdown for a hypothetical project designed for handling an APG volume of 1 BCM/year. The power plant represents more than 70% of the total CAPEX for this project.

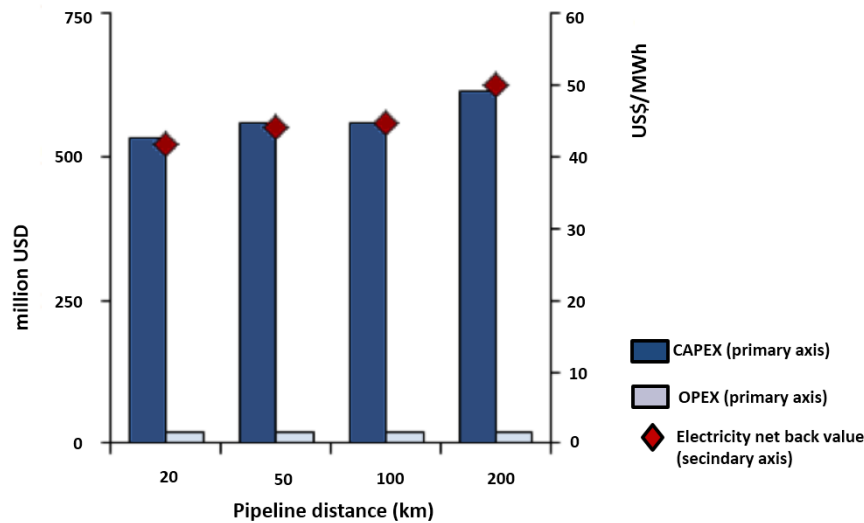
Figure 26: CAPEX for Option 3 depending on the length of the intermediary gas pipeline (for supply of fuel gas)



Source: Carbon Limits analysis

The CAPEX and OPEX related to this gas utilization option have been evaluated for different volumes of APG recovery. The required net-back value of electricity has been evaluated for different distances between the source of APG and the location of the new gas plant for recovery of an APG volume of 0.5 BCM/year is shown in Figure 27.

Figure 27: CAPEX, OPEX and electricity net-back value for 0.5 BCM of APG (Option 3)



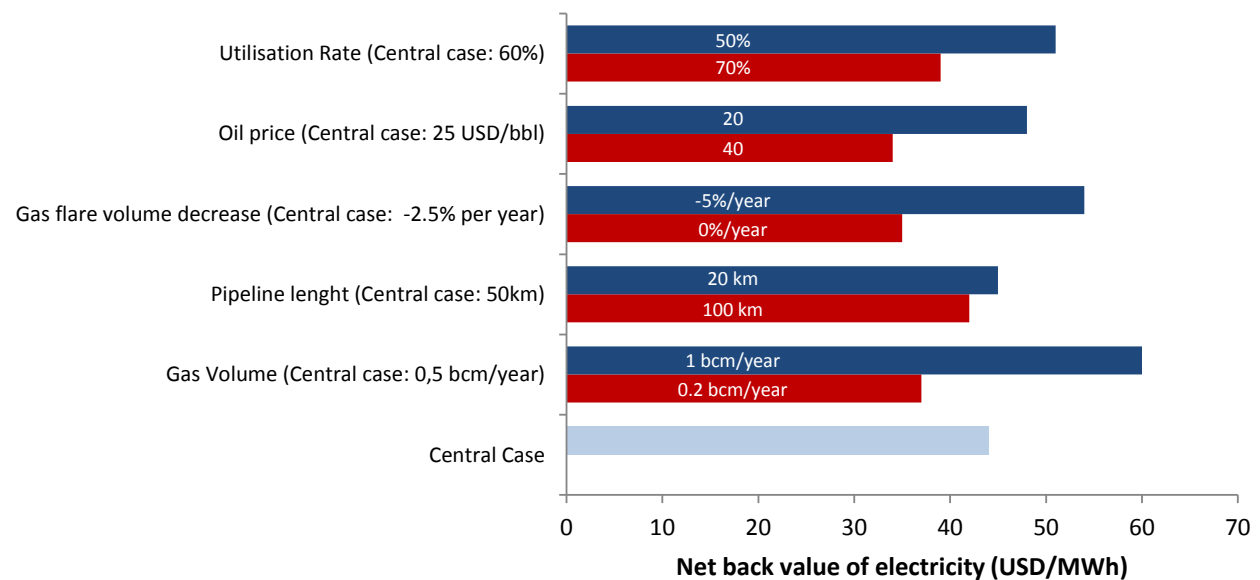
Source: Carbon Limits analysis

⁸⁵ Power plant assumptions: IEA Projected Costs of Generating Electricity – 2010, assumptions for Russia.

The analysis shows that the required electricity net-back value to provide a minimum economic return on investments is under many circumstances higher than the current wholesale electricity price in relevant regions. However, the wholesale price for purchase of grid supplied electricity is in some regions of Russia in the range of ~2,000 RUB/MWh (~70 USD/MWh), and the costs associated with captive diesel based electricity generation can be a factor of four higher than this. For situations where this gas utilization option has been found to be economically attractive, it is important to note that the base case scenario contains an extremely simplified gas gathering network; recovery of the full APG volume at a single site. In case recovery of multiple small, scattered APG streams is required to provide a sufficiently large resource base to supply a new power plant, CAPEX could increase significantly.

Figure 28 presents the results of a sensitivity analysis for this gas utilization option, assuming an APG recovery of 0.5 BCM/year. Large regional power plants using APG have complex economic drivers. The sustainability of the gas supply⁸⁶, the utilization rate (there can be important seasonal variation in power demand within the four target countries, e.g. in Siberia), and to some extent the liquid content of the gas are some of the key parameters influencing the ultimate viability of potential investments in this case.

Figure 28: Sensitivity analysis for Option 3 (Base case: 0.5 BCM/year and 50 km pipeline)



Source: Carbon Limits analysis

3.3.4 Option 4: GTL plant for production of diesel and naphtha

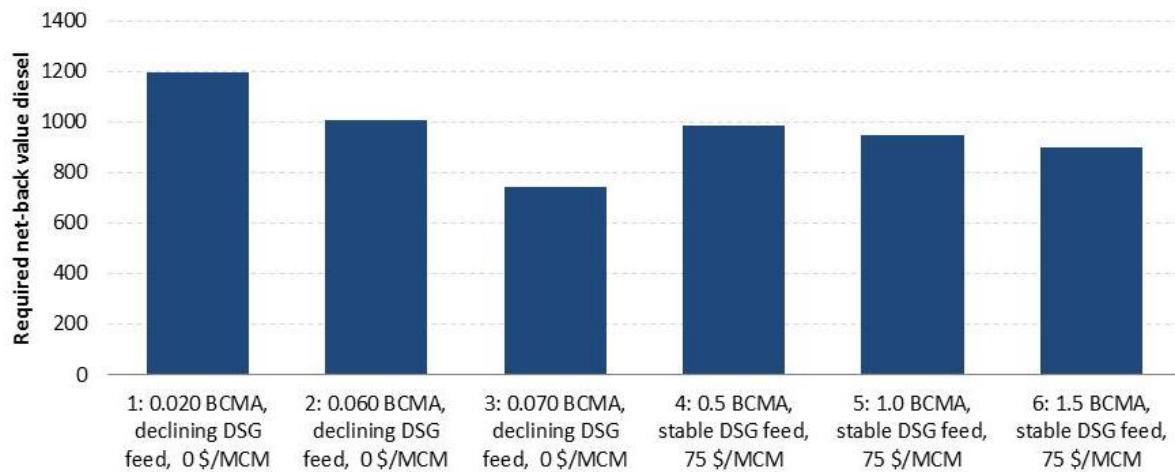
This option differs from the options studied above in terms of the starting point for the assessment of economic viability. This option comprises investments in a GTL plant to produce diesel and naphtha using DSG as feedstock with local storage facilities for liquid products. Extraction of C₃₊ from APG through processing (similar to Option 2 presented in **Section 3.3.2**) can be economically attractive due to significant liquid content in the gas, while DSG in excess of what is used on-site/locally can have

⁸⁶ Recoverable volumes of APG will change over time, and this is really challenging to forecast and has a significant impact on the attractiveness of investments.

limited/negative value (in a few instances DSG is known to be flared after processing, and re-injection of excess gas after processing is becoming more common due to new regulatory requirements for APG utilization). DSG resulting from processing is a highly suitable feedstock for GTL, and availability of stable supplies of DSG with limited net-back value (e.g. either re-injected or flared alternatively) would provide an attractive starting point for considering investments in GTL. DSG often has a low net-back value at production/processing sites due to long transport distances to attractive market outlets, poor access to existing infrastructure and unattractive pricing policies for gas locally. This is often the case in Russia, in particular in remote areas. In some cases, GTL technologies can be applied to convert DSG into products with significantly higher net-back values and easier logistics.

The CAPEX, OPEX and economic attractiveness related to this gas utilization option have been evaluated for six different DSG supply profiles to the GTL plant; declining supply profiles (-2.5% per year) with peak supply of 0.020, 0.060 and 0.070 BCM/year, and stable supplies of 0.5 BCM/year, 1.0 BCM/year and 1.5 BCM/year. Costs have been estimated based on literature review undertaken in Q2 2013. The GTL plant is assumed to consume 10,000 standard cubic feet per barrel, with a product spread of 79% diesel, 19% naphtha and 2% LPG. The required net-back value of diesel to provide 10% return on the overall investment has been calculated, assuming net-back values of 500 USD/ton for naphtha and LPG and 0 USD per feed gas for the three declining profiles and USD 90 per million cubic meter for the three stable supply profiles⁸⁷. The results of the analysis are presented in *Figure 29*.

Figure 29: Required diesel net-back values (USD/ton) for investments in Option 4 with 7 different gas supply scenarios



Source: Carbon Limits analysis

Due to GTL being a capital intensive option for monetization of gas, achieving high capacity utilization is key to economic efficiency (i.e. having stable, long-term gas supplies or a modular solution with good turn-down ratio). As can be seen from *Figure 29*, construction of a GTL plant including a hydrocracking unit to

⁸⁷ The reason for including these latter three cases is that these feed gas profiles represent significant and stable supplies of gas, for which there would likely be alternative uses (i.e. not flared gas). Actual feed costs for monetization of DSG through GTL will depend on a number of site specific considerations, which have not been taken into account in this Study.

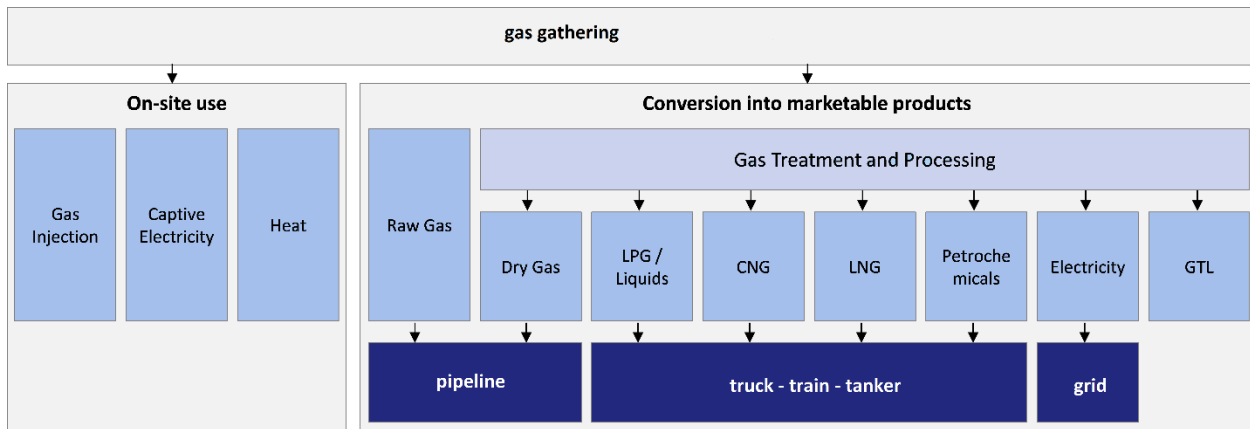
produce diesel, naphtha and minor quantities of LPG could be an attractive gas utilization option in cases where these products can be marketed locally at a significant premium. While it has not been possible to undertake market studies, such significant price premiums are not unrealistic in certain remote areas of Russia.

Numerous GTL and GTC technologies are now available to add significant value to dry lean gas (DSG). As technologies mature, GTL technologies can play a role in improving gas utilization in remote areas under favourable local conditions. Where large and stable gas supplies can be secured and utilized at moderate costs (e.g. in combination with a re-injection scheme at a remote site), GTL technologies can represent an attractive alternative for monetization of the DSG at more moderate price premiums for refined products.

3.4 Summary

A number of technology components (suitable for gas gathering, gas treatment and processing, on-site use, conversion processes and transport of products) can be used to establish various value chains to increase utilization of APG (and reduce continuous flaring at production sites). *Figure 30* provides an overview of the most common APG utilization options.

Figure 30: Overview of APG utilization options



Source: Carbon Limits analysis

The attractiveness of different gas utilization options are highly site specific, and mainly depend on:

- (i) The flare gas volume and its expected variation over time
- (ii) The gas composition (particularly the C₃⁺ content)
- (iii) The local demand and net-back prices for gas, power, heat, diesel, etc.
- (iv) The distances to relevant markets

Table 5 summarizes the key factors influencing the economic viability of the main gas utilisation options in the four target countries.

Table 5: Key factors influencing the economic attractiveness of the main gas utilization options

	Gas gathering (Required for all)	On-site			Conversion to marketable products						
		Electricity	Heat	Re-injection	Raw gas export	Processing only	Processing+				
							CNG	LNG	Methanol	GTL	Electricity
Factors related to the APG supply											
APG Pressure	●	NA	NA	●	NA	NA	NA	NA	NA	NA	NA
APG volume	◐	◐	◐	◐	◐	●	●	●	●	●	●
APG C3+ content	◐	◐	◐	○	◐	●	●	●	●	●	●
Contaminants content	●	●	◐	◐	●	●	●	●	●	●	●
Variability of APG supply	◐	●	◐	◐	◐	●	●	●	●	●	●
Geographical factors											
Total Gathering transport distance	●	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Distance to gas infrastructure	NA	○	○	○	●	●	○	○	○	○	○
Distance to land or sea transport infrastructure	NA	○	○	○	○	●	●	●	●	●	●
Distance to electricity infrastructure	NA	●	○	○	○	○	○	○	○	○	○
Reservoir properties	NA	○	○	●	○	○	○	○	○	○	○
Terrain	●	◐	◐	○	◐	◐	◐	◐	◐	◐	◐
Market related factors (Net back values at the existing infrastructure)											
Net back value of gas	NA	○	○	○	●	●	○	○	○	○	○
Local Electricity price or net back value	NA	●	○	○	○	○	○	○	○	○	●
Netback value of LPG	NA	○	○	○	○	●	●	●	●	●	●
Netback value of Condensate	NA	○	○	○	○	●	●	●	●	●	●
Complexity of commercial set-up	●	○	○	○	●	●	●	●	●	●	●
Capital intensity	○	○	○	◐	◐	◐	●	●	●	●	●

KEY	
Factor influencing greatly the economic viability of the utilisation option	●
Factor influencing the economic viability of the utilisation option	◐
Factor having only a limited influence on the economic viability of the utilisation option	○
Non Applicable	NA

For small volumes, the options for gas utilization apart from on-site use are often not economically attractive in the absence of incentives such as a flaring fine. The economic attractiveness of APG utilization can in some situations be improved by finding integrated solutions, where gas volumes from multiple sites is gathered to facilitate construction of large, centralized facilities and shared downstream infrastructure. However, this can increase the commercial complexity and would require close cooperation among resource owners and investors.

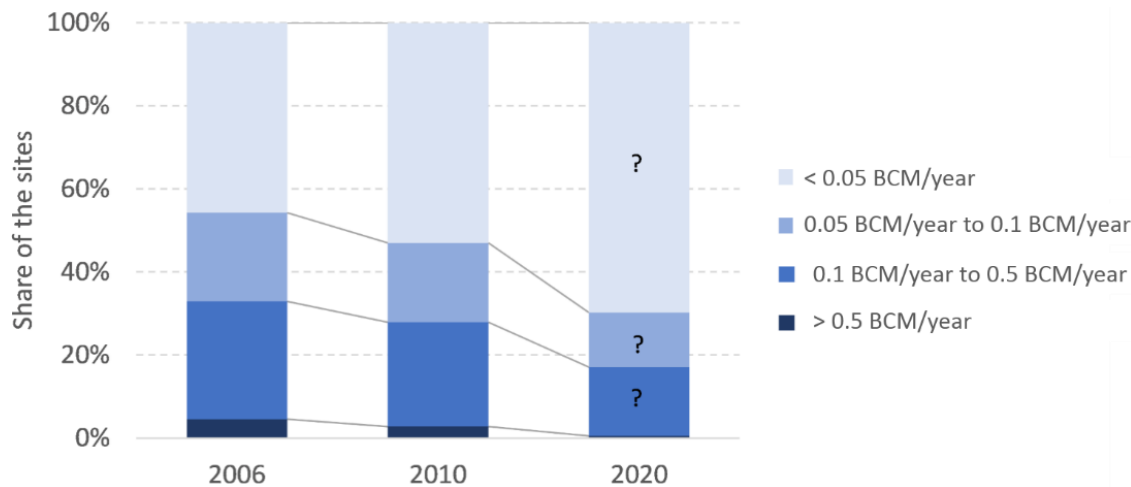
4. How to further improve APG utilization

4.1 Scale and character of the problem

Flaring reduction efforts have been stepped up and major investments have been made in gas utilization over the past 5-6 years in the target countries. This has led to a marked reduction in flaring volumes in Kazakhstan, while total volumes in Russia have stayed at the same level due to new flares in Eastern Siberia having counterweighed substantial reductions in Khanty Mansiysk and other mature oil regions. Azerbaijan has invested in gas utilization solutions so as to keep flaring at a relatively low level. Little information is available about APG utilization investments in Turkmenistan, but there are indications that companies operating oil fields offshore and at the coast of the Caspian Sea have implemented large gas utilization projects since 2010.

For sound economic reasons, progress have been greatest at large flare sites. Already in 2011 some 80% of the flare sites sent less than 100 million cubic meters per year to flare stacks, while less than 10 sites have a flare volume higher than 1 BCM per year. With current corporate actions and regulatory pressures this size distribution will most likely be even more skewed towards small and medium flare sites.

Figure 31: Size distribution of flare sites in target countries



Source: Carbon Limits analysis

There will continue to be large flare sites, primarily connected to new production sites in Russia, but flaring will typically be temporary as gas utilization solutions lag behind in field development and commissioning.

From a political and regulatory perspective therefore, elimination of routine flaring requires a particular focus on medium and small size flare sites where the resource owners may be unable or unwilling to act (on their own). The barriers to flare reduction are well known and recognized. Some barriers have been reduced, among others through political action, while others now are more important with a large share of flare sites being small and medium size often situated in remote locations.

Barriers can be grouped in four broad categories:

- 1. Technical and geographical barriers.** This refers primarily to the location of flare sites and low volume of APG production per field. In particular, scattered and small flare sites in remote locations away from gas infrastructure represent a serious hindrance to APG investments.
- 2. Structural barriers.** Production/flare sites are typically owned and operated by a variety of companies while gas infrastructure, including processing facilities and transport lines, are owned and/or controlled by large entities, often monopolies. In many cases APG investments have been stalled due to lack of commercial agreement on terms for access of stranded gas into the infrastructure. This problem has been given considerable political attention recently with reforms being passed both in Russia and Kazakhstan. However, it remains to be seen to what extent and how quickly processing and transportation access for APG producers will be improved.
- 3. Economic barriers.** This refers to economies-of-scale and external economic parameters such as gas and power prices, as well as taxes and other public schemes, which may impact on the financial viability of APG investments. A common problem is that power and gas prices are kept low for political reasons and hence reduces the “true economic value” of APG utilization investment. This problem continues to be an important barrier in all target countries of this Study. On the other hand it can be added that in the absence of good monitoring, companies may be ignorant of the economic potential from productive use of the APG.
- 4. Regulatory barriers.** As described on **Section 2** the target countries have specific regulations of flaring (albeit less direct in Azerbaijan), but despite some improvements in the regulatory practice in past 3-4 years important deficiencies exist. Unrealistic and broad based targets and prescriptive approaches coupled with weak and/or inconsistent enforcement mechanism have been prevalent and become even less effective and efficient as more of flare reduction investments at the outset will be uneconomic. A key to further flare reduction is therefore removal of regulatory barriers (see next section).

In the past, associated gas was considered a waste product, or by-product, of crude oil production with little economic value. Among industry executives the attitude has changed, due to higher value for the gas, regulatory and political pressures and company-internal standards. Still, APG investments must compete with other projects for financial, human and managerial resources, and beating oil production expansion investments is often difficult. Generally it is easier to have funds allocated for APG utilization investments when they are part of new field developments than flare elimination investments from existing producing fields, particularly if such fields are in decline and have limited remaining economic lifetime. Regulations therefore play a particularly important role in relation to flare elimination from existing fields where the economic return on investment may be uncertain or negative.

4.2 Do “best practice” regulations and policies exist?

From this Study it can be concluded that regulatory structures and practices differ greatly among the four target countries. Although there have been improvements, it can also be concluded that major regulatory deficiencies persist. A natural question to be asked therefore is whether there exist a set of “best practice regulations” that can be applied. The short answer is no; a blueprint for effective and cost efficient flare reduction does not exist. Regulations and policies on flare reduction must be firmly rooted in the legal/regularly structure and tradition of the country and its institutional capability. Nevertheless there are some guiding principles drawn from international experiences that are highly relevant to apply, and which only partially are incorporated in regulations in the target countries. These can be grouped into three broad categories presented in the following.

4.2.1 Principles for effective regulation

It is important that policies and the primary or secondary legislation recognize that the costs of flare reduction efforts vary by site and that cost efficiency is applied in regulatory practices. This means that low cost cases should be taken before those with high costs, and that fiscal incentives may be offered when flare reduction investments from a private perspective are clearly uneconomic.

Regulations normally entail an application for allowance to flare, which often are granted in special cases (e.g. for safety reasons and in cases where investments have significant negative economic returns) and based on specific criteria. It is important that rules and procedures for application and approval are clear and transparent.

An impartial and predictable regulatory enforcement requires that clear rules and guidelines exist for monitoring, reporting and verification of flaring. Data reporting requirements must also be attuned to what realistically can be monitored. Creating trust in the sustainability and constancy of the regulation is also essential to encourage compliance.

As with all regulations it is essential that there exist capable regulatory bodies that act independently, and further that such bodies do not have overlapping and/or unclear functions.

4.2.2 Regulatory practices

In line with the principle of cost efficiency, regulatory bodies should set targets and requirements based on site specific circumstances. This is of course a challenge given the inherent bias in access to information between the resource owner and the regulator. In general the response to this is to have a regulation where the resource owner has an incentive to reveal correct information. This will more often be the case when companies are engaged in a dialogue with the regulator about targets and timetables to reach a desired outcome than in the case that regulations are inflexible with punitive measures such as flare fines or other penalties. Still, regulatory bodies need to have the opportunity to ultimately “use the stick” if the “carrot” does not work.

4.2.3 Supporting policies

As noted in **Section 4.1** there are a number of barriers to flare reduction investment that can be removed through policies and measures other than flare regulations. Imposing cost-based and non-discriminatory power and gas prices are obvious examples as are legal reforms which give non-discriminatory access to grids and gas infrastructure. Several countries have regulations which give APG preferential rights with respect to pipeline/grid access. Most recently Russia imposed such a reform through amendment to the law “On gas supply of the Russian Federation” (see **Section 2.1**). Other examples of supportive policies applied in several countries are tax relief and investment grants in cases where the APG investments are clearly uneconomic. Such measures becomes more and more important as countries progress to higher APG utilization rates and remaining flare reductions become costly and difficult to achieve.

4.3 New technologies and commercial approaches

4.3.1 Partnerships

Given that important challenges remain for projects that at the outset do not benefit from economies-of-scale there will be an important role to play for political and regulatory authorities; and the focus will have to be on non-prescriptive approaches. The great variances in the economic attractiveness of APG utilization investments call for flexibility on the hands of regulatory authorities and innovative commercial solutions from companies. The small and medium size projects may be commercially unattractive as standalone projects pursued by an oil producer, but can become viable through a productive partnership involving companies with different expertise and willingness to take on project risks.

Figure 32: Partnerships for APG investments



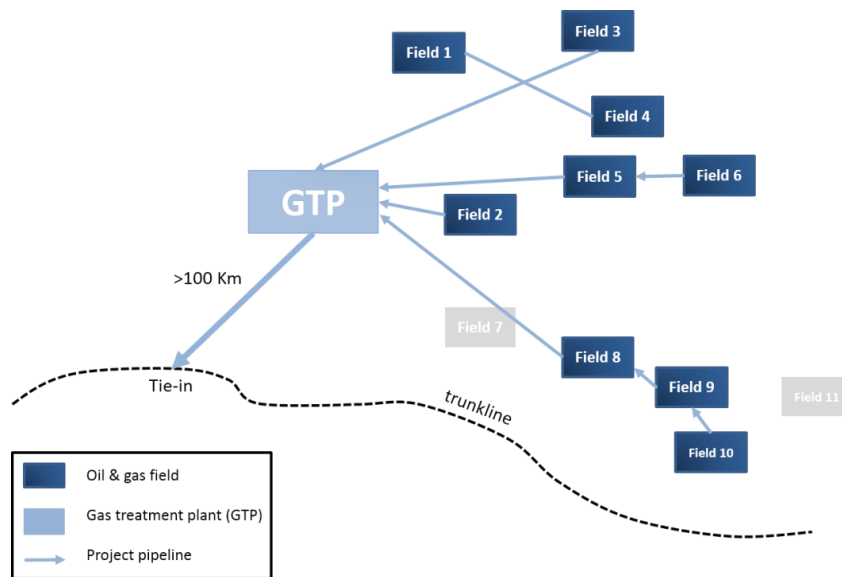
Moreover, bringing together supplies from several fields will typically improve the economics of APG utilization through economies-of-scale, improved capacity utilization and enhanced value of the gas (through greater security of supply).

There are examples of APG investment projects being implemented in Russia and Kazakhstan through such partnership arrangements. In general a development can be seen whereby other players than subsoil users are seeking business opportunities in the “APG value chain”. Still, persistent barriers need to be overcome, including commercial incentive structures, economic, regulatory and cultural/psychological factors, in order to have dialogues established and commercial agreements settled. Regulatory authorities as well as finance institutions, such as the EBRD and the World Bank, can play an important role here in establishing partnerships based on trust and a better understanding of the respective commercial perspectives and risk/reward preferences.

4.3.2 Examples of clustering

As part of this Study, APG investments involving clusters of fields have been analysed. An APG investment cluster typically involves gathering of APG from multiple fields, central gas processing and treatment, and export of dry gas, LPG and condensate to markets. These investments require participation and commitment of several independent subsoil users to enable economic utilization. The case illustrated in *Figure 33* involves gathering of APG from ten oil fields.

Figure 33: Clustering of APG supplies from multiple fields



Source: Carbon Limits

A specific model⁸⁸ has been developed as part of this Study to facilitate high-level analysis of techno-economic aspects of integrated APG utilization schemes. The model has considerable flexibility in terms

⁸⁸ «Model for Analysis of Clustering of Associated Petroleum Gas Resources» (MAC-APG)

of adjustment to various physical and commercial/institutional configurations of a cluster. Using this model, cases of clustering have been studied through the following steps:

1. Determination of physical project boundaries of a cluster and the institutions involved
2. Assessing the overall economic result of the investment
3. Identification of separate development stages and required sub-investments
4. Gathering of high quality input data from relevant potential investments partners
5. Techno-economic modeling of different sub-investments, including analysis of possible net-back values and transaction prices for gas deliveries
6. Assessing sensitivities and risks of the sub-investments and the total cluster investments

In one specific case studied in Kazakhstan with APG supplies initially planned from three fields (one subsoil user) the internal rate of return on the project was 12% but improved to 18% when four more fields were included (involving further three subsoil users). In this case subsoil users, processing plant owners and a pipeline company would take part in the investments, and the challenge would be to agree on terms for delivery along the value chain of the gas. Typically there are risks upstream related to the total volume and profile of APG production and downstream due to uncertain medium and long term value of the gas in various market segments. How these risks are shared between the different players in a clustered investment is inevitably closely linked to the regulatory regime and what can be expected in terms of regulations and gas policies in the future. For clustering of investments to work therefore, activity participation for regulatory and political authorities is an essential factor.

Small scale gas to liquids

Gas to liquids⁸⁹, through the development of small and medium scale applications have increasingly attracted attention as APG utilization options. Technology costs have come down and international manufacturers, and in the case of Russia a few domestic companies, are pursuing business opportunities. No full-scale investments have yet been implemented but many companies are seriously considering investments and a few pilot schemes are under way. The rationale for gas to liquids for APG is becoming more interesting as more of the stranded APG will be in remote small and medium size fields (high local value of liquids relative to gas, transportability, small and medium scale solutions with modular design). The most important factor for the financial viability of GTL is the price differential between the liquids and gas, which has increased substantially in recent years. As the analysis of this Study shows the economics of gas to liquids based on “normal market prices” are often marginal, but local prices for liquids may be often high for logistical, political or other reasons and hence can justify investments even without regulatory measures.

Still, it will most likely take time for this technology to become an important part of APG investments. No full scale projects have been developed in the target countries and technology risks are real and hence a barrier. As noted above, political authorities, regulators can play a role in bringing together various industrial partners, and possibly also clustering APG sources, so as to find viable investment solutions with

⁸⁹ Including both the traditional «Fischer-Tropsch» gas-to-liquids and “gas-to-chemicals” (see Chapter 3).

acceptable allocation of risks and rewards among commercial partners. The EBRD and GGFR may also be able to play a role as facilitators. There are signs of broader partnership arrangements being discussed in Russia and with technology providers and downstream market operators engaging in the commercial/risk taking part of such investments.

4.4 Capital requirements for APG utilization investments

Considerable financial resources are needed both to reduce existing flares and to avoid or minimize flaring from new production sites. High-level estimates made as part of this Study indicate that some USD 23 billion may be needed in APG utilization investments in Russia till 2020, of which 2/3 are for new field developments and 1/3 is to bring to existing APG production to a utilization rate of 95%.

Table 6: Estimated capital expenditures for APG investments in the target countries in Billion USD

	Size of site in BCM/year potentially flared				
	< 0.05 BCM	0.05 - 0.1 BCM	0.1 - 0.5 BCM	> 0.5 BCM	All
Existing/old flares	1.3	2.1	3.5	0.5	7.5
New fields/sites	0.8	4.5	8.2	1.9	15.5
Total	2.1	6.6	11.8	2.4	22.9

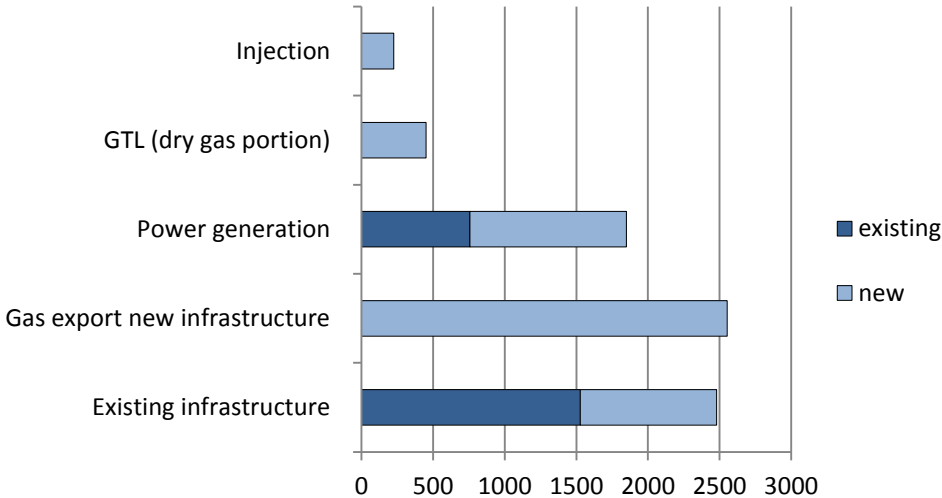
Source: Carbon Limits analysis

The estimates of investments required to establish infrastructure to meet APG utilization targets for existing and new production sites by 2020 are uncertain and qualitative by nature. Estimates are based on a large number of assumptions, including the development of Russian oil production, the share of total APG production in 2020 from new developments, the effects of projects under implementation at existing flare sites, the “remoteness” of existing and new APG production sites and new infrastructure (GPPs and GTPPs), the required installed capacity relative to actual APG recovery, the cost synergies associated with designing integrated APG solutions for new developments, the size distribution of APG volumes to be recovered at existing and new production sites, the optimal technology mix to utilize gas from existing and new production sites and the unit cost of new infrastructure to utilize APG using alternative technologies at different scales. The estimates presented in this report are made for an assumed mix of technological solutions that take into account locations of APG volumes in 2020 and the size distribution of these APG sources. These technologies would yield products with different market values (ranging from unprocessed APG delivered to GPPs to diesel produced using GTL technologies). In general, capital intensive utilization options generally yield products that would attract higher values in the market. The market value of the products resulting from the estimated capital investments have not been estimated in this study.

The estimates only provide an indication of the magnitude of the required investment funds.

Figure 34 presents a breakdown of the estimated capital requirements for minimizing flaring at small flare sites (< 0.1 BCM/year) till 2020, while Figure 35 shows a similar breakdown for medium and large flare sites.

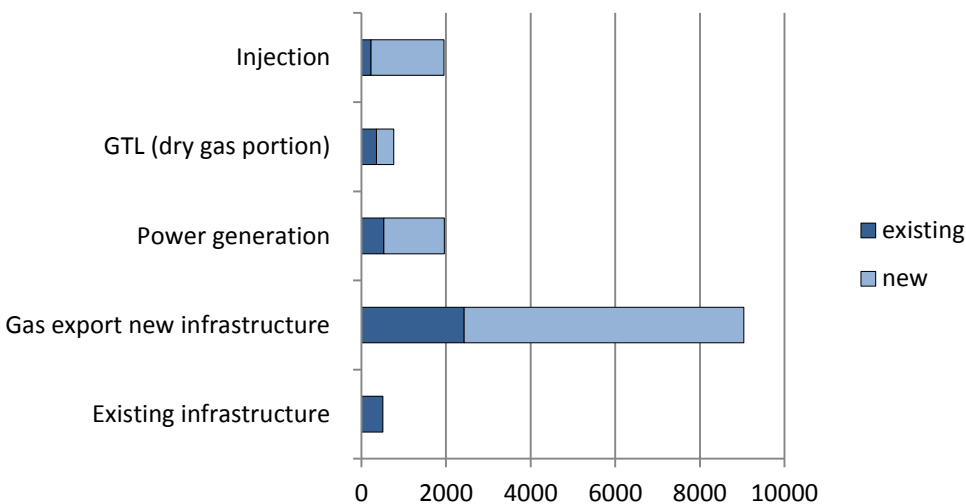
Figure 34: Capital expenditures for small flare sites (< 0.1 BCM/year) till 2020 in Russia, Million USD



Source: Carbon Limits analysis

It should be noted that the assumed capital intensity of the different utilization options utilized to estimate total capital requirements vary significantly. It is assumed that a relatively large portion of the small flare sites can be connected to existing gas infrastructure (at modest costs), while small-scale power generation and establishment of new gas export infrastructure would represent other important utilization options over the next 7 years. For medium and large sites, re-injection, power generation and new infrastructure for gas processing and export of products are assumed to represent the most attractive utilization options.

Figure 35: Capital expenditures for medium and large flare sites (> 0.1 BCM/year) till 2020 in Russia, Million USD



Source: Carbon Limits analysis

4.5 Optimization of gas utilization rates

The Study has had as one of the objectives to identify bankable investment projects within the four target countries, and the focus of this Report has thus been on investments in infrastructure (including processing capacity) to recover and utilize APG to reduce continuous production flaring. However, even when infrastructure to facilitate recovery of APG has been successfully established, non-negligible volumes of gas may still be flared during oil and gas operations due to a variety of reasons (e.g. during maintenance or unexpected shutdown of an installation). Such flaring may account for a significant portion of APG production, and potential measures to minimize operational flaring are briefly presented below.

To minimize flaring, operators must develop a detailed understanding of the causes for the operational flaring. *Figure 36* shows common causes of operational flaring, divided into two groups:

- Continuous flaring, which covers the flaring which take place during normal operations⁹⁰. It includes the gas from both the pilots and the purge gas, but also other continuous sources of gas like produced water degasing or seal gas.
- Intermittent flaring, which includes flaring due to maintenance, emergency shutdown, technical failures, etc.

For each of the causes of flaring, potential options to minimize the flare volumes have been listed. These options include some investment options, but also process measures. All measures listed in *Figure 36* are based on mature technologies.

Optimizing the APG utilization rate require a continuous process, comprising a number of optimization steps which together can result in utilisation rates above 95% or 98%⁹¹. Systematic recording of the root-causes of gas flaring in an installation is central to identify the site specific cost effective measures to minimize gas flaring:

- For continuous flaring, pilot gas consumption and purge gas emissions can be reduced through the implementation of purge reduction devices or the optimisation on the pilots used. . Further reductions can be achieved through installation of a Flare Gas Recovery Unit. It is located upstream of the flare to capture some or all of the waste gases and compress them to inject them into the gas line. A Flare Gas Recovery Unit can be installed on both high-pressure and low-pressure flares and presents the advantage of reducing up to 100% of the continuous flaring⁹². However, the costs and the benefit of this measure vary depending on the local circumstances.
- For intermittent flaring, we can distinguish between two categories of measures: i) improvement in the regularity of operations, and ii) improvements in operational procedures. The first category may typically include installation of spare capacity for gas injection and/or export, online washing of gas compressors and turbines to reduce the maintenance and integrating power supply between production units to improve the overall reliability. Often these are win-win options and

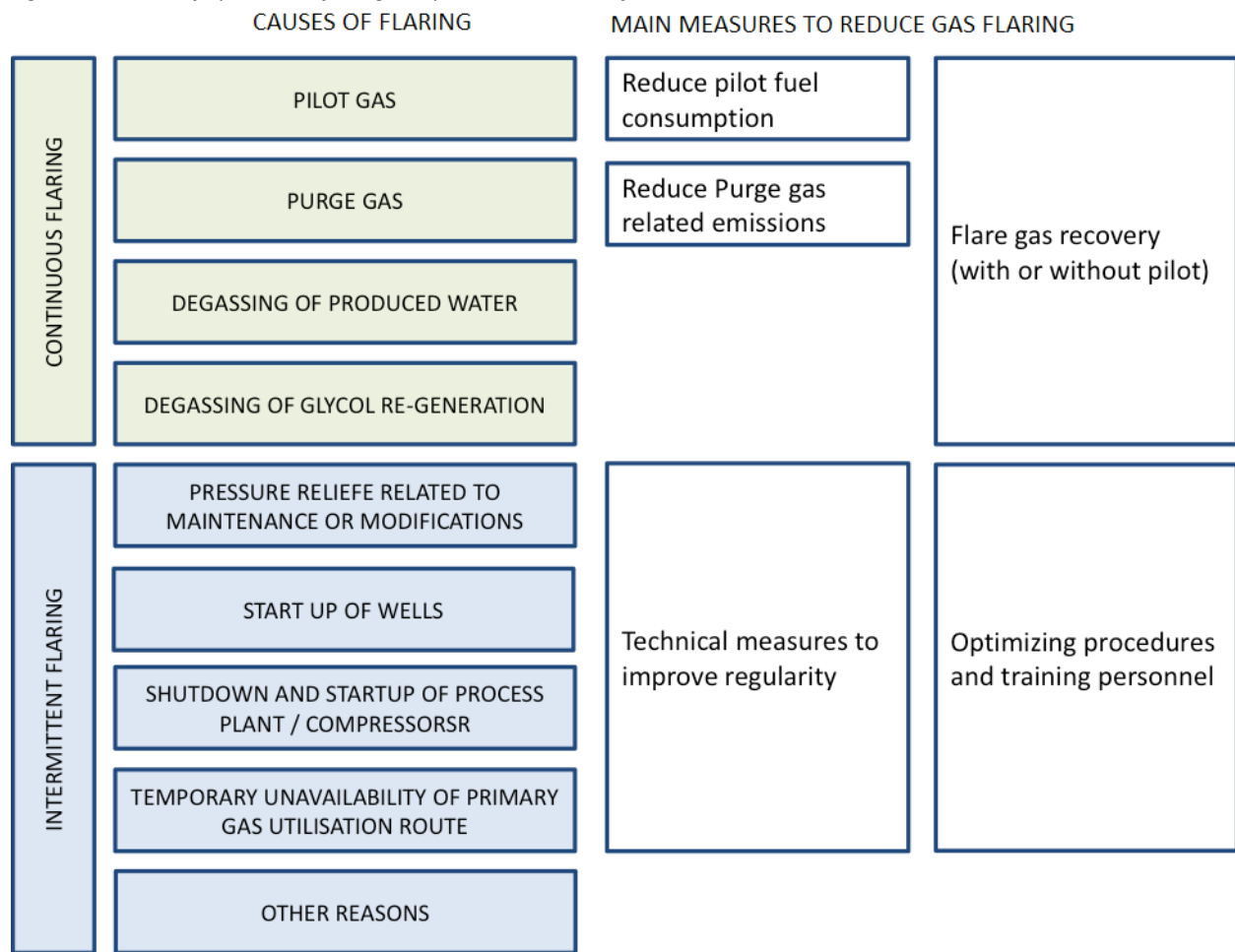
⁹⁰ When primary gas utilisation routes are established to avoid production flaring.

⁹¹ Yearly average including routine and non-routine flaring.

⁹² If used in combination with a flare ignition system.

are commonly pursued by operators. The second group of measures includes measures not entailing large investments, but focuses rather on improving operational procedures. Examples are planning of maintenance depending on the seasons and other related activities, the training of personnel to improve awareness of the operators on flare reduction. These measures are relatively cheap to implement and have variable impact on the volume of gas flared.

Figure 36: Causes of operational flaring and potential measures for reduction



Though many of these measures provides some co-benefits (in terms of reliability for example), regulations plays an important role in encouraging continuous improvement to keep the flaring as low as possible.

4.6 Concluding remarks

The project team believes that due to corporate standards and policies and regulatory pressures oil companies will continue and possibly step up their efforts to reduce and avoid flaring of associated gas. Priority will be given to medium and large projects (greater than 0.1 BCM per annum). National political and regulatory authorities have an important role to play in spurring investments in smaller size projects. Given the great variability in the financial viability of small and medium size APG utilization investments, regulations should be flexible both with respect to the application of the “carrot and stick” and with the timing of flare reduction targets. Further, active steps should be taken in preparing the ground for new and innovative commercial approaches to tackling of the flaring challenges. Clustering of APG supplies into a centralized gas infrastructure may in many cases be the only option for financially viable investments. Small scale technologies (such as GTL) are becoming interesting options for stranded associated gas in remote small and medium size fields. In such cases, also, several commercial actors may be involved (e.g. technology providers, gas processing companies, downstream fuel suppliers, finance institution) and they may be interested in taking on commercial risks that traditionally have been carried by oil companies. Again, political authorities, regulators and institutions such as the EBRD can play a role in bringing together various industrial partners enabling clustering of associated gas sources, so as to find viable investment solutions with acceptable allocation of risks and rewards among commercial partners.

Glossary

ACG: Azeri–Chirag–Guneshli
APG: Associated Produced Gas
API: American Petroleum Institute
BarG: Gauge pressure
bbl: Barrel
BCM: Billion Cubic Meters
BCMA: Billion Cubic Meters per year
BP: British Petroleum company
C₂H₆: Ethane
CAC: Central Asia Centre
CAPEX: Capital Expenditure
CDM: Clean Development Mechanism
CDU TEK: Central Dispatch Office of the Russian Fuel and Energy Industry
CES: Common Economic Space
CH₄: methane
CHP: Combined Heat Power
CIS: Commonwealth of Independent States
CNG: Compressed Natural Gas
CNPC: China National Petroleum Corporation
CO: Carbon Oxide
CO₂: Carbon dioxide
DME: dimethyl ether
DSG: Dry Stripped Gas
EBRD: European Bank for Reconstruction and Development
EOR: Enhanced Oil Recovery
EU: European Union
FEED: Front End Engineering Design
GGFR: Global Gas Flaring Reduction Partnership
GIS: Geographic Information System
GOR: Gas to Oil Ratio
GPP: Gas Processing Plant
GTC: Gas to Chemical
GTF: Gas-To-Fuel
GTG: Gas-To-Gasoline
GTL: Gas-To-Liquid
GTPP: Gas Turbine Power Plant
H₂S: Hydrogen Sulphide
HC: Hydrocarbon
IEA: International Energy Agency
INPEX: International Petroleum Exploration Corporation
IRR: Internal Rate of Return
JI: Joint Implementation
JSC: Joint-Stock Company
KZT: Tenge Kazakh (currency of Kazakhstan)
LLP: Limited Liability Partnership

LNG: Liquefied natural Gas
LPG: Liquefied Petroleum Gas
MoU: Memorandum of Understanding
MTBE: Methyl Tertiary Butyl Ether
NGL: Natural Gas Liquid
NOAA: National Oceanic and Atmospheric Administration
OPEX: Operational Expenditure
PSA: Production Sharing Agreement
RUB: Russian Ruble
SEI: Sustainable Energy Initiative
SNG: Synthetic Natural Gas
SOCAR: State Oil Company of Azerbaijan Republic
SOL: Sum Of the Light intensity
TAPI: Turkmenistan-Afghanistan-Pakistan-India
UGSS: Unified Gas Supply System
USA: United States of America
USD: US Dollar
WWF: World Wildlife Fund

Units

USD
RUB
KZT
EUR
Barrel (bbl)
million (M)
Cubic meter (m³)
Billion cubic meters (BCM)
Bar gauge (barG)
Degree Celsius (°C)

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