Columbia Center on Sustainable Investment

A JOINT CENTER OF COLUMBIA LAW SCHOOL AND THE EARTH INSTITUTE, COLUMBIA UNIVERSITY

A Policy Framework to Approach The Use Of Associated Petroleum Gas

July 2016

Shayan Banerjee

Perrine Toledano

About the Columbia Center on Sustainable Investment

The Columbia Center on Sustainable Investment, formerly known as the Vale Columbia Center on Sustainable International Investment, is a joint center of Columbia Law School and the Earth Institute at Columbia University and a leading applied research center and forum for the study, practice and discussion of sustainable international investment. Our mission is to develop and disseminate practical approaches and solutions to maximize the impact of international investment for sustainable development. CCSI's premise is that responsible investment leads to benefits for both investors and the residents of host countries. Through research, advisory projects, multi-stakeholder dialogue and educational programs, CCSI focuses on constructing and implementing a holistic investment framework that promotes sustainable development and the mutual trust needed for long-term investments that can be practically adopted by governments, companies and civil society.

Acknowledgement:

The authors are extremely grateful to Albert Bressand and Thomas Mitro, both senior fellows with CCSI for their thorough reviews and inputs. The authors are also very grateful to the Sabin Center for Climate Change Law for conducting two case studies (Iraq and Russia).

Suggested Quote

Shay Banerjee, Perrine Toledano, "A Policy Framework to Approach the Use Of Associated Petroleum Gas," Columbia Center on Sustainable Investment, Columbia University, (2016).

Table of Contents

I. Overview

Crude oil and natural gas consist of a combination of hydrocarbon molecules. Crude oil is a liquid both at normal surface and underground conditions while natural gas is a vapor at normal surface conditions and underground, it can exist either as a "vapor or something like a bottle of carbonated soda".[1] The lightest hydrocarbon is methane, with ethane, propane, butane and "natural gasoline" being the increasingly heavier fractions. The larger the proportions of heavier molecules in a hydrocarbon mixture, the more likely it is to exist as a liquid at atmospheric conditions.[2,3]

Thus, historically, petroleum producers, only interested in the crude oil, disposed of lighter hydrocarbons by 'venting' them into the atmosphere, creating a byproduct known "Associated Petroleum Gas (APG)." Today, it is far more common for petroleum producers only seeking the liquid to instead flare the produced APG, a process that converts the lighter hydrocarbons into carbon dioxide, water, and other chemical impurities. Both practices, with venting being worse than flaring release highly detrimental greenhouse gases into the atmosphere.

Since the hydrocarbons disposed as APG are potentially valuable and commercially viable sources of energy, venting and flaring activities are not only harmful to the environment and public health, but also waste a valuable non-renewable energy resource that could otherwise drive positive economic outcomes. Efforts have been underway for decades to reduce flaring by extracting value from gases by selling them in markets for petrochemicals or power production (methane), decentralized heating and cooking (propane, butane), fuel for tractors (propane), among other uses. Strategic optimization of APG use would eliminate economic waste generated by flaring, improve energy efficiency, expand energy access, contribute to climate change mitigation, and promote sustainable development.

In 2015, the World Bank launched the "Zero Routine Flaring by 2030" initiative to call attention to the problem of routine flaring and encourage better utilization of APG on a global scale.[4] The initiative seeks to engage oil companies, governments, and development institutions

---

[1] Training modules of International Human Resources Development Corporation (IHRDC) available at: https://www.ihrdc.com/els/po-demo/module01/mod_001_02.htm

[2] " In general, the deeper a rock formation is located in the Earth's crust, the higher its temperature will be. Thus, the type of petroleum that formed through these processes depended largely on the depth of the source rocks. In relatively shallow source rocks, where temperatures ranged from about 60 to 80°C [140 -176°F], the organic matter was converted into heavy oil. At lower depths and higher temperatures, from about 80°C to 175°C [176°F to 347°F], the heavier, long-chain organic molecules began to break up into shorter molecules and form medium and light oil. Where temperatures exceeded 175°C [347°F], the molecules became even shorter and lighter, with more and more matter transformed to rich gas until, by the time it had reached 600°F [315°C], all of it had been transformed to dry gas (methane)." Source: IRDC, op. cit.

[3] See Annex or a composition of the different types of petroleum produced.

[4] The World Bank, "Zero Routine Flaring by 2030," available at: http://www.worldbank.org/en/programs/zero-routine-flaring-by-2030

in a unified effort to eliminate routine flaring at existing oil fields as soon as possible, and no later than 2030. Furthermore in December of that year, the 21st meeting of the Conference of the Parties of the United Nations Framework Convention on Climate Change (COP 21) reached the "Paris Agreement[5]" that sets the goal of limiting global warming to "well below two degrees Celsius" above pre-industrial levels, and to strive to limit the increase to 1.5 degrees Celsius. "The Paris Agreement marks a historic milestone in curbing human-induced climate change, yet the real challenge lies ahead, in implementation."[6]

To contribute to both the World Bank's efforts and the implementation of the Paris Agreement, the Columbia Center for Sustainable Investment ("CCSI") has reviewed case studies from around the world and prepared the present policy paper to outline governmental and operational strategies for successful broad-based deployment of APG use technology. As such, the paper should serve as guidance for regulators, policymakers, and industry leaders seeking to develop practical approaches to unlock the economic value of APG.

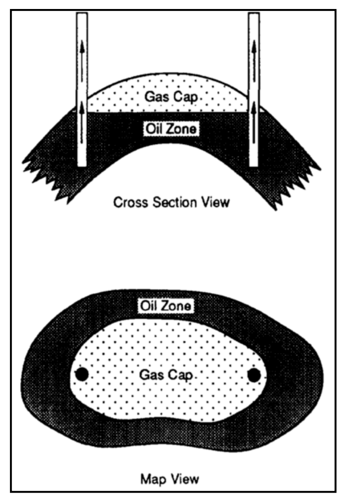
A. Definitions

APG is a broad term for gas associated with the oil in the reservoir, and therefore includes both gas dissolved in the oil ("solution gas") and gas residing above oil in the reservoir ("gas cap gas").[7] Each of these APG types is described below.

- ***Solution Gas*** - Subsurface crude oil almost always contains dissolved methane (CH4) and other hydrocarbons including ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}) and pentane (C_5H_{12}). Those components are released as APG when the reservoir pressure drops during the extraction process.

- ***Gas Cap Gas*** - A gas cap is present in a reservoir if the latent oil pressure is below bubble point[8] at the time of discovery (Figure 1[9]). As oil is extracted, the

Figure 1: Gas Cap



Source: AAPG Wiki

[5] UNFCC's Paris Agreement, available at: http://unfccc.int/paris_agreement/items/9485.php

[6] CCSI's announcement its 11th Annual Columbia International Investment Conference, available at: http://ccsi.columbia.edu/2016/11/02/11th-annual-columbia-international-investment-conference-climate-change-and-sustainable-investment-in-natural-resources-from-consensus-to-action/

[7] PFC Energy, "Using Russia's Associated Gas: Prepared for the Global Gas Flaring Reduction Partnership & the World Bank," (2007), available at: http://siteresources.worldbank.org/INTGGFR/Resources/pfc_energy_report.pdf.

[8] In thermodynamics, a liquid's bubble point at a given temperature is the pressure at which the first bubble of vapor forms.

[9] Retrieved from the open access resource for the petroleum geosciences community maintained by the American Association of Petroleum Geologists (AAPG) at http://wiki.aapg.org/Drive_mechanisms_and_recovery

overlying gas cap expands downward and invades the producing oil zone. Over the production window, reservoir yield contains increasing amounts of APG and ultimately only APG.

The most abundant component of APG, and the one for which the largest market exists, is methane. APG however always contains some fractions of the other "light" hydrocarbons, i.e. ethane, propane, normal butane, isobutene, pentanes and traces of heavier hydrocarbons usually noted as C5+ (see Figures 7 and 8 in Recommendation 4). If these other gases are a very small fraction (which practically means if the APG can be transported and sold like methane under the local market technical parameters applicable to "natural gas"), the gas is said to be "dry". By contrast, APG will be called a "wet" gas if it contains a high concentration of the heavier gaseous hydrocarbons and cannot be transported and sold as "natural gas". These other fractions, which are referred to as *Natural Gas Liquids* ("NGLs"), must be separated from the methane[10] at a Gas Processing Plant ("GPP"), which separates out dry methane from the other components.

APG are also a significant component of reservoirs rich in condensates (the term condensate, which does not have a precise definition, referring to a slightly broader spectrum of hydrocarbons than NGLs). These reservoirs, which can also be referred to as light-oil reservoirs (as is the case for unconventional tight oil plays in the U.S.) consists mostly of light hydrocarbons. If, as is the case in the U.S., operators sell these condensates under the more favorable term of "light oil", they will need to dispose of the lights fraction, namely methane with some residual NGLs. In such cases, the methane considered "associated" in relation to the production of the condensates.

Given rising energy demand globally, there is reason to believe that the revenue potential of APG utilization will grow over time. Technically, the "natural gas" component of APG can be used in a number of ways, including power generation in remote or regional markets, after distribution through high-pressure pipeline networks or under liquefied form, use for in-place electricity generation, and reinjection into the reservoir for enhanced oil recovery. After being processed, NGLs are separated into their individual components that all have different market outlets and industries (see further details in Recommendation 4). The industry usage are determined by practical considerations (e.g. the fact that that the heavier gases can become liquid at the pressure and temperature of pipeline transportation or other critical operations) and by commercial considerations, most notably the thermal content accepted for the sale of "natural gas" to industrial and retail users ("natural gas" being mostly methane with some acceptable small fraction of ethane and traces of other gases).

If a company seeks to produce oil but has not deployed a comprehensive strategy for APG utilization, however, the company must dispose of accumulated APG to avoid the risk of fire and explosion within production facilities. The most conventional disposal instrument involves the controlled burning of the APG. This method, called "flaring," disposes of the gas by releasing it

---

[10] N. Hyne, *Dictionary of Petroleum Exploration*, op. cit, pp. 204.

into the air. Chemically, flaring works by stimulating combustion reactions between the gaseous hydrocarbons and atmospheric oxygen in the air.[11] A properly designed flare system operates at 98% combustion efficiency or higher, so the main outputs are water vapor (H_2O) and carbon dioxide (CO_2).[12] The 1-2% of incomplete combustion produces carbon monoxide (CO), black carbon, total hydrocarbons, particulate matter, and volatile organic compounds.[13]

"Venting" is another disposal mechanism that is rather rare today and that was vastly used a few decades ago in oil fields. Now however it is remains an issue with the gas fields where some gas can be vented in case of gas well testing, planned and unplanned non-routine depressuring of processing equipment and gas pipelines. It involves the direct release of the APG into the atmosphere.[14] If the APG is released at a high enough pressure, the hydrocarbons mix with the air without the need for combustion. In comparison to flaring, venting releases larger quantities of methane and volatile organic compounds into the atmosphere.

Often, flaring that is considered "routine" occur due to the normal operations of the facility, with individual event durations ranging from 1-hour to 1-year.[15] In contrast, safety flares may be necessary in emergency situations when equipment pressure poses an explosion or injury threat. Additional flaring over and above a normal or zero flare situation can also often take place over a few days, weeks or months whenever certain normal events take place, such as completion and hook-up or repairs and maintenance of a gas pipeline.

Apart from the abnormal situations of flaring mentioned above, there is another technical reason why eliminating flaring completely is not achievable. Natural depletion and pressure declines often means that the APG being produced is higher at the beginning of a project and lower at the end. In contrast, a GPP will possess a maximum processing capacity that does not fluctuate and is invariably lower than the maximum production capacity of the field. This is done so as not to overbuild capacity and add unduly to the capital and operating costs. Thus, particularly in the early years, the APG produced is greater than APG processed, creating a need to flare the surplus APG. This flaring can be somewhat controlled by timing of when individual wells come on to production or by choking back production, but the alignment between the gas field production and the gas processing plant will never be perfect.

---

11 J. Kearns et. al., "Flaring & Venting in the Oil & Gas Exploration & Production Industry," OGP Environmental Quality Committee (Jan. 2000), available at: http://www.ogp.org.uk/pubs/288.pdf.

12 "Processing Natural Gas," NaturalGas.org, op. cit.

13 Caliber Flaring,"What is Flaring" (2016), available at: https://rfn.caliberplanning.com/index.php?content=faq&section=flaring

14 "Processing Natural Gas," NaturalGas.org, op. cit.

15 Non-Routine Flaring Management: Modeling Guidance, Alberta Environment & Sustainable Resource Development, pp. 3, available at: http://environment.gov.ab.ca/info/library/8848.pdf

B. 3 objectives in minimizing Flaring

CCSI considers each of the following objectives to be relevant to the broader goal of sustainable development in the field of APG utilization.

1. Eliminating Economic Waste

Flaring wastes a valuable resource that could be used to advance the development of producing countries. For example, if all APG currently subject to flaring were used for power generation, the world would enjoy an additional 750 billion kWh of electricity – more than the entire African continent's current electricity consumption.[16] Alternatively, and as previously stated, APG could be utilized in a number of productive ways unrelated to power generation. Since APG is non-renewable, this shortfall in economic value can never be gotten back.

A central objective of government APG regulation should be to optimize the economic value from APG utilization now and in the future. Policies must foster incentives to encourage consideration of the economic benefits of APG utilization at the planning stage.

2. Improving Environmental & Public Health

As previously discussed at length, flaring causes considerable damage to the environment and to human health. From the perspective of mitigating climate change, according to the World Bank's Global Gas Flaring Reduction Partnership, flaring produces a substantial greenhouse gas footprint, resulting in approximately 300 million tons of global emissions each year.[17] Here, it should be noted again that while flaring releases mainly carbon dioxide emissions, venting releases mainly methane emissions. Since the global warming impact of methane is 21 times higher than that of carbon dioxide,[18] flaring is preferable to venting for sustainability purposes, though both are harmful to the environment. For this reason, venting is often fully prohibited while flaring can be allowed under exceptional circumstances. Minimizing flaring would reduce carbon emissions as much as removing 77 million cars from the road[19] and would go along way towards the implementation of the Paris Agreement.

Air pollution associated with flaring and venting can result in chronic health problems, including bronchial, chest, rheumatic, and eye illnesses.[20] Flaring also negatively impacts livelihood, causing acid rain that damages local crops, building structures, and surrounding ecosystems. An optimal APG utilization strategy should seek to minimize greenhouse gas emissions and damage to surrounding communities.

---

[16] The World Bank, "Zero Routine Flaring by 2030," op. cit.

[17] The World Bank, "Zero Routine Flaring by 2030," op. cit.

[18] Living Earth, "What are the impacts of flaring and venting?", available at: http://oilandgas.livingearth.org.uk/key-challenges/flaring-and-venting/what-are-the-impacts-of-flaring-and-venting/

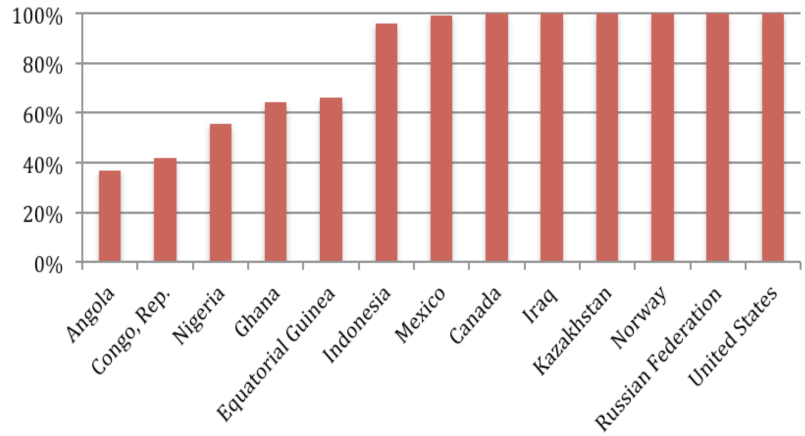
[19] The World Bank, "Countries and Oil Companies Agree to End Routine Gas Flaring," Press Release (April 17, 2015), available at: http://www.worldbank.org/en/news/press-release/2015/04/17/countries-and-oil-companies-agree-to-end-routine-gas-flaring

[20] The World Bank, "Zero Routine Flaring by 2030," op. cit.

3. Increasing Energy Access

Several oil-producing countries have not developed a commercial energy sector providing their population with access to modern energy sources. For example, Angola has achieved an electricity access rate of only 37%.[21] (See Figure 2). In such countries, there is significant potential in the use APG to meet the energy needs of citizens. Furthermore, for oil fields that exist far from an interconnected grid, APG solutions such as their use in local power generation may represent an attractive way to reduce costs associated with expensive purchased diesel or heavy fuel. Since energy consumption is a key driver of economic growth, an important function of APG utilization strategy is to reduce the overall cost of energy for as many individuals as possible.

Figure 2 Electricity Access Rates in APG Producing Countries



Source: World Bank, 2012

C. Note on the methodology

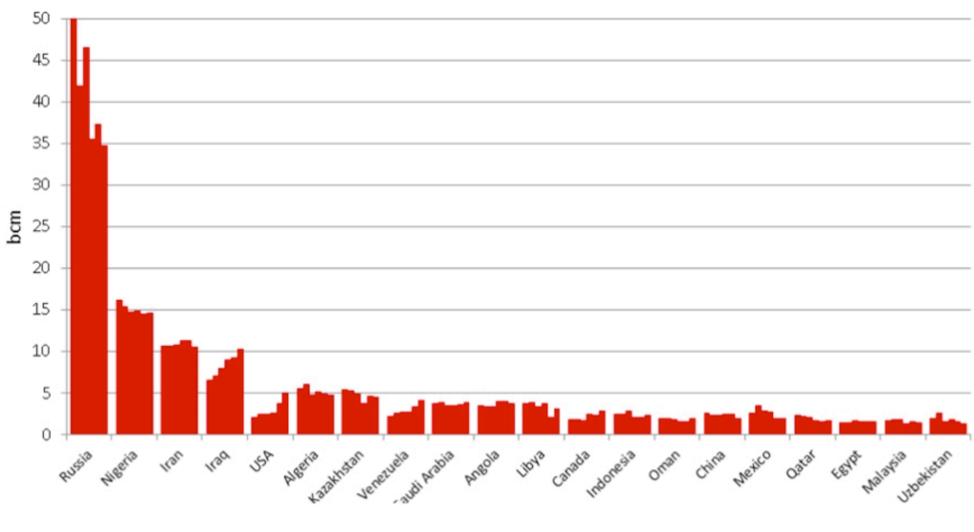
While entering the technical intricacies, market constraints and institutional challenges of APG use, this paper proposes a model policy framework for policy makers structured around four recommendations. These recommendations are informed by an extensive literature review, interviews with experts and a set a case of studies that CCSI conducted in detail: Angola, Canada, Equatorial Guinea, Ghana, Indonesia, Iraq[22], Kazakhstan, Mexico, Nigeria, North Dakota, Norway, Republic of the Congo, Russia[23] and Texas. As shown in Figure 3, some of these countries are among the top twenty gas flaring countries, while others are among the best performers. The analysis and policy recommendations in this paper involved the conclusions drawn from all of these studies.

[21] World Bank Table on Access to Electricity by Country, 2012.

[22] Iraq's case study was carried out by the Sabin Center for Climate Change Law at Columbia University and CCSI.

[23] Russia's case study was carried out by the Sabin Center for Climate Change Law at Columbia University and CCSI.

Figure 3: Top 20 gas flaring countries



Source: NOAA Satellite Estimates, 2012 [24]

II. Model Policy Framework & Recommendations

A. Recommendation One

Delegate regulatory oversight of flaring abatement policy to a single independent agency or corporation with credible powers to enforce said policy. Where use of an independent regulator is not possible, take adequate steps to create a credible and transparent enabling environment for investors.

Any fiscal, monetary, or reporting framework aimed at converting flaring operations to APG utilization operations must be based on robust regulatory fundamentals. In particular, the presence of a strong, independent regulatory body to measure and report requirements, monitor flare and vent volumes, enforce regulations, and compel the payment of penalties, is generally preferred, particularly when there is some state interest in petroleum development projects. Indeed, the centrality of an independent regulator to a successful flaring abatement regime is discussed widely and at length in the literature,[25] and our case studies have confirmed that this factor is quite significant to the success of utilization regimes.

---

[24] According to the World Bank, "NOAA is currently processing 2013 data and working to calibrate the data to derive estimates of flare volumes. However, a number of circumstances, including the use of new VIIRS infrared technology for more accuracy, have delayed the process. The World Bank-led Global Gas Flaring Reduction Partnership and NOAA are working to make 2013 gas flare volume estimates available as soon as possible." (Source: http://www.worldbank.org/en/news/feature/2014/09/22/initiative-to-reduce-global-gas-flaring)

[25] Global Gas Flaring Reduction Partnership, "Guidance on Upstream Flaring & Venting," Policy Regulation (2009), available at: http://siteresources.worldbank.org/INTGGFR/Resources/fr_policy_regulations_guidance.pdf.

The Texas case study is instructive in that matter (See Box 1).

Box 1: Texas – The state of the art of an independent regulator

There, flaring is regulated by the Texas Railroad Commission ("RRC") and the Texas Commission on Environmental Quality ("TCEQ") , each of which approaches flaring regulation from a different slant. The RRC in particular is mostly concerned with preserving nonrenewable energy resources. Thus, the RRC regulations, which have been operative since 1947, strive to prohibit the wasteful flaring of APG.[26] The RRC, which under state law exerts primary regulatory jurisdiction over the oil industry, issues flaring permits to well operators under its Statewide Rule 32, a power that the Texas Supreme Court has upheld on three separate occasions.[27] Over the last several decades, the RRC has used this power to issue fines, warning notices, and bring suits against companies across the state that violate flaring regulations. Some argue that the RRC could stand to use its powers more extensively than it has, [28] but there is little debate that the agency serves as a credible counterbalance to oil and gas interests when it comes to effective utilization of APG.

In addition, operators in Texas seeking to commit to flaring must apply for standard air permits through a process administered by the TCEQ. Unlike the RRC, the TCEQ is primarily concerned with addressing air pollution that arises out of flaring. Pursuant to Title V of the Clean Air Act, the TCEQ, as a state agency, is charged with reviewing and approving air pollution permits for industrial and commercial sources. Although the TCEQ, as the state agency, is given this authority under the statute, the federal EPA may take control if it determines that monitoring of air pollution is inadequate – adding an additional layer of accountability to regulatory apparatus. Recently, the TCEQ has used its authority under the Clean Air Act to regulate flaring activities with the goal of limiting air pollution. During this process, the TCEQ may attach conditions that it sees fit based on the facility's location and individual characteristics. The permit itself also enters the public domain and becomes available for comments from the public during the TCEQ's evaluation. This serves as an opportunity for community groups and other local governing bodies to raise concerns about the impact of the flaring activities at issue.[29] Citizens are also able to issue complaints to the TCEQ about air pollution resulting from flaring. The TCEQ typically responds to such complaints within twenty-four hours and subsequently conducts an on-site investigation to ensure compliance with environmental regulations. If a violation of air quality standards is found, the TCEQ takes "appropriate enforcement action" to ensure that the

[26] Tex. Admin. Code §3.32.

[27] For instance in 1947, RRC issued an order shutting in all 615 oil wells in Seeligson Field in South Texas until flaring of APG was eliminated and measures were taken to utilize the gas. Operator filed suits challenging the orders. The Texas Supreme Court upheld the RRC orders (source: D, Otiotio, "Gas flaring regulation in the oil and gas industry: A comparative analysis of Nigeria and Texas regulations," *Academia.edu* (May 2013).)

[28] J. Tedesco and J. Hiller, "Top Flaring Sites Lacked State Oversight," San Antonio Express News (2015), available at: http://www.expressnews.com/business/eagleford/item/Up-in-Flames-Day-1-Flares-in-Eagle-Ford-Shale-32626.php

[29] NSR Guidance for Flares & Vapor Combusters, TCEQ, available at: http://www.tceq.state.tx.us/permitting/air/guidance/newsourcereview/flares/nsr_fac_flares.html

violation is corrected and notifies the submitter of the complaint in writing about the results of such actions. After the notification is issued, the submitter is given the opportunity to publicly comment on the resolution. The entire process, from submission to resolution and comment can be tracked online. During 2015, over 7,500 air pollution complaints were resolved under this system.[30] In this way, the TCEQ leverages transparency and direct public engagement to maintain its credibility and pursue enforcement as an independent regulator.

While not all countries possess the financial and human resources to replicate the regulatory apparatus described above, the Texas example demonstrates how delegating regulatory authority to an agency that maintains a certain degree of independence can aid in flaring abatement efforts. For the reasons discussed below, failure to provide jurisdiction over flaring activities to an independent regulator can become a roadblock to effective APG utilization.

As discussed in greater detail in ***Recommendation Two***, there will be many instances in which the interests of the operator conflict with the pursuit of otherwise socially optimal flaring abatement. In such cases, a system regulator whose interests are insufficiently severed from the production and marketing interests of oil companies is unlikely to hold operators fully accountable for flaring activities. The case study in Nigeria is illustrative (See Box 2).

Box 2: Nigeria - Regulation and conflict of interest

In Nigeria, oversight of flaring regulations – along with all oil and gas policies – falls under the purview of the Federal Ministry of Petroleum ("MPR"), who oversees these regulations through the Department of Petroleum Resources ("DPR"). In particular, the DPR is tasked with granting flaring allowances and monitoring exploration and production activities. The MPR also controls the Nigerian National Petroleum Corporation ("NNPC"), a government oil company that exerts Nigeria's interests in the oil industry and typically holds a 60% state equity share in the domestic petroleum and gas related joint ventures involved in flaring.

Thus, the MPR is both, through the DPR, a participant in and, through the NNPC, a regulator of oil and gas activities in Nigeria. This reality generated conflicts of interest reflected in lax enforcement of flaring regulation. According to reports, anti-flaring regulations in Nigeria are regularly not enforced against NNPC joint ventures.[31] In addition, the NNPC has repeatedly defaulted on cash call obligations, creating a high level of mistrust among investors that has generated an inability to raise needed funds for projects that might otherwise support domestic utilization strategies. This situation was compounded by the fact that the regulated domestic price offered for the gas was notoriously too low as compared to the market. As a result, the handful of operators interested in APG utilization have largely turned their attention to high return export options that, while preferable to flaring, may not create the same social benefits as

[30] TCEQ Complaint Tracking Database, available at: http://www2.tceq.texas.gov/oce/waci/index.cfm
[31] T. Oyewunmi, "Examining the Legal & Regulatory Framework for Domestic Gas Utilization and Power Generation in Nigeria," J. of World Energy L. and Bus. (2014), pp. 538.

domestic utilization of the APG.

The Nigeria experience shows that an autonomous regulator whose activities are not institutionally interwoven with production might be better equipped both to penalize flaring and oversee conversion to socially optimal utilization.

Despite our preference for an independent regulator, it is important to note that there are steps that can be taken to ameliorate concerns arising when perfect regulator independence is not possible. Broadly, these steps include oversight of the regulator by a robust legislative regime, establishment of the National Oil Company (NOC) as a credible financial partner to outside investors, and the fostering of technical expertise within the regime.

For example, in **Norway**, there is no true independent regulator (see Box 3).

Box 3: Norway – No independent regulator but credible and transparency investment framework

Norway's Ministry of Petroleum and Energy ("MPE") has overall responsibility for the petroleum activity on the Norwegian Continental Shelf and is also the largest shareholder in Statoil, the Norwegian NOC, holding 71% of shares.[32] Meanwhile, the technical issues related to flaring fall under the regulatory jurisdiction of the Norwegian Petroleum Directorate ("NPD"), which is also administered by the MPE. Despite its administrative proximity to Statoil, the NPD has proven to be an effective flaring regulator, closely monitoring the development of oil and and gas fields and strictly enforcing flaring prohibitions. The MPE administers its activities under the direct oversight of the Parliament of Norway, and it is to be assumed that this reality mitigates conflict of interest problems that might otherwise arise due to the bundling of regulatory and production interests.

Where regulator independence is not possible, it is imperative that the NOC establishes itself as a credible financial partner to outside investors. In **Angola**, for example, there has historically been very little legislation on flaring and little systemic measurement and restoring of gas flaring. Since the state-owned company, Sonangol, is both a participant and a regulator of production, it has had to overcome a perception that its interests are not independent from those of the operators. Recently, it has taken a firm stance on promoting APG use in the country, even over oil revenues, and has served as active participant in directing APG to utilization projects.[33] Sonangol is also widely regarded for never defaulting on equity obligations, a reality which likely led to the acceleration of APG utilization projects in recent years.[34] This characteristic stands in sharp

[32] Statoil, "The Norweigian State," available at:
http://www.statoil.com/en/investorcentre/share/shareholders/pages/stateownership.aspx

[33] The World Bank, "Angola's Major Natural Gas Project to Cut Emissions from Flaring," (Sep. 2013), available at: http://www.worldbank.org/en/news/feature/2013/09/20/angola-major-natural-gas-project-to-cut-emissions-from-flaring.

[34] G. Lino, "Angola's State-Run Oil Company Sonangal 'Stable',"African Business News (July 2015), available at:

contrast to the aforementioned situation in Nigeria, where the NOC has largely served as an impediment to investment in viable utilization technology.

The independent regulator or NOC should also possess the technical capabilities to manage policy issues that naturally arise with the proliferation of an APG industry, such as consumer protection, dispute resolution, and information asymmetries occurring in negotiations between buyers and sellers. Failure to comprehend the technical and economic geography of flaring may result in political backlash and prove counterproductive (see the example of Kazakhstan in Box 6 later on).

As an additional note, since certain segments of the APG value chain (e.g. pipelines) are prone to monopolization by vertically integrated entities, there is a risk that production interests will engage in anticompetitive behavior to discriminate against competitors for network access and investments. As such, an aspect of "independence" on the part of a regulatory agency must be to prevent monopolistic behavior by owners of transmission networks. Such behavior, if left uncorrected, is likely to prevent certain operators from achieving cost-effective abatement while increasing prices on final consumers. Thus, to promote an efficient market, the regulator must ensure open and fair third party network access for producers of APG. Although third party access can often be secured through contractual negotiations, the substantial bargaining power held by owners of transmission networks may necessitate regulator intervention where non-discriminatory third party access is not secured. In **Alberta**, for example, the Energy Resources Conservation Board, which is responsible for oil and gas regulation in the province, where operators and network controllers cannot come to agreements, the ERCB is able to establish unilaterally the conditions necessary for APG transmission.[35] In contrast, investors largely view the NNPC in **Nigeria**, which operates transmission networks as discriminatory to third parties, a reality that serves to dampen financing opportunities.[36]

Finally, the success of flaring regulatory regimes may be enhanced by a clear set of definitions and boundaries backed by a reputable legal authority. For example, independent regulators in **Texas, Indiana and Alaska** have previously utilized authorities granted under existing statutes to regulate flaring. When oil companies challenged these actions, the respective state supreme court in each state upheld the corresponding regulations.[37] Given the influence often held by oil companies over legislative and judicial processes, regulators of flaring must remain protective of their jurisdiction and take care to ensure that actions are grounded in verifiable authority that can withstand political and litigative pressures.

---

http://gasparlino.com/sonangol-stable/.

[35] Global Gas Flaring Reduction Partnership, "Guidance on Upstream Flaring & Venting," op. cit.

[36] T. Oyewunmi, "Examining the Legal & Regulatory Framework for Domestic Gas Utilization and Power Generation in Nigeria," op. cit.

[37] A.B. Klass and D. Meinhardt, "Transporating Oil and Gas: US Infrastructure Challenges," Iowa L. Rev. 100 (2014), pp 947.

Key Takeaways from Recommendation One

- Effective enforcement of flaring and venting regulations requires the presence of a regulator whose interests are severed from the economic interests of the operator.
- Where perfect regulator independence is not possible, creating transparent and predictable processes for managing issues that arise in flaring regulation can enhance the credibility of the regulator and foster an enabling environment for investors.
- Midstream functions in the APG utilization value chain are vulnerable to anticompetitive behavior, the resolution to which requires active state efforts to ensure third party access to distribution infrastructure.

B. Recommendation Two

1) Prohibit and sanction all venting and flaring activities except in instances where the facility operator has successfully applied for a special permit or waiver and 2) issue technical guidelines for reducing associated impacts.

1. Implement a systemic framework for prohibiting venting and flaring and granting exceptional permits

Although there are circumstances under which total emission abatement will not be feasible, these should be the exception rather than the rule. Multiple countries have implemented procedures in parallel with emission restrictions to permit flaring in exceptional circumstances and when absolutely necessary.

For projects requiring a flaring permit, an environmental impact assessment evaluating the consequences of any flaring should be required and made public along with the permit. Such assessments are more useful in dissecting the complexity of the issues at stake than are the traditional cost-benefit approaches employed by private industry. Environmental impact statements enable policymakers to achieve a better grasp of the long-term costs and benefits of decisions by focusing explicitly on the interlinkages occurring between the environment and social and economic development. Flaring in particular is a multi-faceted issue that impacts a biodiversity, public health, quality of life, and long-term economic production. Furthermore, the full benefits of utilizing APG are unlikely to be fully considered in a traditional cost-benefit approach, which relies explicitly on prices, because the long term benefits of increasing energy access, for example, are often difficult to quantify.[38]

As an additional matter, governments should prohibit APG venting in almost all situations. Given the increased environmental and public health damage caused by venting relative to

---

[38] United Nations, "Opportunities for Cost-Benefit Analysis: The Value of Environmental Impact Assessment," *Improving Responses: Interlinkages in Policy*, available at: http://www.unep.org/dewa/Africa/publications/AEO-2/content/141.htm

flaring, regulators may choose to grant venting permits on a case-by-case basis, but must place a high burden on the operator to demonstrate that it is the only viable solution and the regulator should issue case-specific technical guidelines to minimize harmful emissions.

Countries may choose to permit flaring according to case-by-case evaluation or pursuant to the issue of universal guidelines. A comparison of these procedures as they have been implemented in Canada and Norway, is discussed below.

In **Canada**, permits for flaring are issued according to universal guidelines as specified in Directive 060. Under the Directive, an operator's decision tree is expressly structured as follows[39]:

1) Eliminate flaring
2) Reduce flaring
3) Improve flaring efficiency

This procedure requires the regulator, in considering a flaring proposal submitted by an operator, to first consider whether flaring is necessary, in accordance with economic, environmental, and social factors. Second, the regulator should require the operator to take measures to reduce the total volume of APG that is flared. Third, the regulator should ensure that the operator takes measures to maximize the efficiency of combustion so as to minimize harmful emissions. Based on this procedure, the regulator approves or rejects the operator’s proposal, issuing additional regulatory conditions and parameters as necessary. In making its determination, the regulator considers a maximum industry flaring volume.

In **Norway**, the permitting process is subject to case-by-case evaluation by the NPD. In particular, the Petroleum Activities Act of Norway does not stipulate specific flaring targets, but provides: "Flaring of petroleum in excess of the quantities needed for normal operational safety shall not be allowed unless approved by the Ministry. Upon application from the licensee, the Ministry shall stipulate, for fixed periods of time, the quantity which may be produced, injected or cold vented at all times."[40] Under the law, the NPD evaluates the flaring equipment and operating procedures that are submitted by the operator. The operator's application must identify the level of emissions and abatement technology applied. The limits are established by the regulator in response to the application, taking into consideration applicable national and regional standards. Environmental impact assessments are required in each instance and, as in the case of Canada, are made public along with the permit.[41]

In deciding on the particular regulatory regime, governments should take into account the

---

[39] Energy Resources Conservation Board, Directive 060, Calgary Office (2011), available at: http://www.aer.ca/documents/directives/DraftDirective060.pdf

[40] G. Nurakhmet, “Associated Gas: One Problem, Different Approaches,” Kazakhstan International Business Magazine (2006), available at: http://investkz.com/en/journals/46/74.html.

[41] CCSI, Norway APG Utilization Study, June 2014

particular characteristics of the industry as well as its own regulatory capabilities. One recent example occurs in **Mexico** in early 2016, when the National Commission of Hydrocarbons issued a new set of technical guidelines for the use of natural gas.[42] Through the guidelines, the Commission is seeking to implement new methods of measuring the flaring and venting of APG, to improve the certainty and measurability for the handling of gas, and to move towards preventive regulations promoting the utilization of gas beyond reinjection that cannot absorb all the APG generated by new fields. The regulation contains a robust No-Flare policy, as Article 6 permits flaring only when technical and economic analysis reveals it to be the only viable alternative (i.e. where utilization is not possible). This analysis would take into account the composition and volume of APG, the proximity of the processing, transportation and distribution infrastructure, the value of the gas and the value of the necessary investments to use the APG. In this manner, the guidelines contain elements of case-by-case evaluation, as the regulator and operator are expected to work together to find the best solution for a particular field. Furthermore, the regulation requires pursuant to Article 7 that operators who flare maintain the financial resources to cover damages caused by flaring while the amount of the sanctions will be determined according to the Hydrocarbons Law or the project – related contracts (Article 35). If the latter, this can also be a case-by-case approach but one cannot help but wonder if the goals of Article 7 would be more efficiently served by a more explicitly defined and universal penalty per unit of flaring. This idea is discussed in later sections.

As a general matter, case-by-case regulation may be better suited for countries in which operating wells are larger and more concentrated, while universal guidelines may be preferred where operating wells are distributed more sparsely. Furthermore, case-by-case evaluation may be infeasible for countries lacking a strong regulatory apparatus, and in such instances a universal guideline outlining acceptable flaring practices may be preferred.

2. Reduce flaring externalities by setting minimum standards and issuing standard technical guidelines to increase flare efficiency

In circumstances where flaring is permitted, there is little economic incentive for the operator to take steps to improve flare efficiency and mitigate environmental harm through innovation if governments does not develop and distribute guidelines and requirements for efficient flaring.

As a starting point, governments should implement the regulations suggested by the Clean Air Strategic Alliance, which include imposition of a minimum heating value, avoidance of liquid hydrocarbons to flare, limitations on the visibility of emissions, and compliance with ambient air quality standards.[43]

The regulator should also require all flare systems to operate at a combustion efficiency of 98% or higher. Conceptually, this means that the percentage of flare emissions that are not

---

[42] Diario Oficial de la Federacion, "Techniques for utilization of natural gas in the exploration and extraction of hydrocarbons," July 1, 2016, http://dof.gob.mx/nota_detalle.php?codigo=5422286&fecha=07/01/2016.

[43] Energy Resources Conservation Board, Directive 060, op. cit.

completely oxidized to CO_2 should be 2% or lower. The reason behind this mandate is that the non-oxidized flare components discussed in Section I.A.1 cause far more environmental damage than CO_2. Furthermore, 98% combustion is representative of current standard industrial practice and therefore an attainable objective for all flare system operators.[44] Poor diligence by the operator can nonetheless result in low combustion efficiency. Regulators can mitigate this risk by requiring operators to properly address the variety of factors that result in low flare performance. Regulatory actions that can ensure efficient flaring are discussed below.

- ***Regulate utilization of assist media*** - Most flare operators utilize steam or air, commonly referred to as "assist media," at the flare stack to protect the flare tip from damage and promote turbulence for inducing mixture into the air. From an environmental perspective, assist media are necessary to ensure that flares do not produce visible emissions. Nonetheless, excessive use of assist media can hamper flare performance. For this reason, it is important for flare operators to find the appropriate balance with utilization of assist media. Regulators can guide operators by studying assist media in flaring and imposing a range of appropriate usage.

- ***Require active monitoring of flaring*** – Flare performance is also hindered when the dimensions of the flare tip are manipulated by high crosswind[45] or when the flame and burner become separated due to excessive air induction ("flare lift off"). These problems can be addressed by continual monitoring of wind speed, flare dimensions, and flare tip velocity. The cost of this monitoring should be borne by the operators as a condition of securing a flaring permit.

Key Takeaways from Recommendation Two

- Prudent regulation of flaring centers on the implementation of a blanket No-flaring policy, subject to the issuance of permits in the relatively few instances where flaring and venting is necessary.
- The issuance of venting permits should be considered as a last resort and very rare measure. Those permits should be closely monitored given the higher disastrous impact of venting on environment as compared to flaring.
- The issuance of flaring permits should be subject to a strict regulatory process that requires consideration of long-term environmental and social harms at the planning stage and compliance with operational guidelines requiring maximum flaring efficiency.

C. Recommendation Three

Foster a regulatory environment that enables market-driven utilization strategies by resorting to high

[44] M. McDaniel, "Flare Efficiency Study," EPA Contact (1983), available at: http://www3.epa.gov/ttn/chief/ap42/ch13/related/ref_01c13s05_jan1995.pdf

[45] Crosswind refers to wind possessing a perpendicular component to the direction of the flare.

penalties and carefully using subsidies to unlock necessary infrastructure investment for APG use

There are multiple options for utilizing APG, and which option is most economical will depend on circumstance. In particular, the optimal utilization strategy for a particular operating facility will be determined by the facility's individual energy needs, how much APG it actually produces, and the well's access to processing and distribution infrastructure. In theory, if the penalty on flaring is set at the marginal social cost of the associated environmental damage, market pressures will compel the operator to arrive at the optimal solution on its own. That is, when the operator determines that the cost of paying the penalty is higher than the cost of implementing an APG utilization strategy, it will choose to invest in the necessary utilization infrastructure. Where multiple utilization options are available, the operator will prefer the option that is cheapest. In practice, however, the presence of market failures as well as economic interdependencies between APG utilization and other policy areas may prevent an optimal outcome in the absence of targeted policy interventions.

In some cases, the operator may lack knowledge or expertise on APG utilization, and the regulator may be best positioned to correct this information asymmetry. As governments engage in the regulation of flaring, they are likely to gain special knowledge and build networks that can be leveraged to drive positive developmental outcomes. Abatement strategies are likely to be the most successful when governments take an active role in learning about utilization techniques and guiding companies in reducing flaring, preparing internal procedures, attracting sufficient financing, and creating all other required conditions for cost-effective implementation (see the case of North Dakota in Box 3).

Box 3: North Dakota: Pro-active role of the government to learn about abatement strategy

In 2013 the University of North Dakota, under the direction of the **North Dakota** Industrial Commission and U.S. Department of Energy, studied the potential for distributed end-use technologies for APG produced in the Bakken oil fields.[46] The study found that on-site utilization was both the cheapest strategy to implement from the perspective of the operator and would also help the state address a local surge in demand. One of two electric utilities serving the area, the Basin Electric Power Cooperative forecasted a load increase from 600 MW to 1900 MW between 2010 and 2025, which on-site power generation at Bakken would help meet.

Due to the substantial *ex ante* capital investment often required for APG utilization projects, the regulator should ensure that an enabling legal and fiscal framework is in place to encourage development – particularly when APG use is still in nascent stages (see Box 4).

Box 4: Tax incentives in Angola, Nigeria and Alberta (Canada).

[46] C.A. Wocken et. al, "End-Use Technology Study – An Assessment of Alternative Uses for Associated Gas," Energy and Environmental Research Center (2013), available at: https://www.undeerc.org/Bakken/pdfs/CW_Tech_Study_April-2013.pdf.

In **Angola,** there is an attractive fiscal framework in place providing lower taxation for APG projects and a no flare policy stipulating that capital expenditures borne by companies for storage and delivery of APG to Sonangol, the state-owned oil company, is cost recoverable against profit oil. [47] (Note here that cost recovery against oil production enables a larger subsidy than if it was against gas production as gas PSA terms are often at lower rates of profit sharing. The impact of cost recovery (and the cost of the subsidy to the government) is much greater when allowed against the oil PSA). In Soyo, where Sonangol is constructing a LNG facility with various International Oil Companies (IOCs), the project has been declared of public interest and benefits from a project-specific tax holiday of 144 months, as well as zero-cost pipeline access. Similarly, in **Nigeria,** where the legislature enacted Decree No. 30 in part to address disincentives to APG utilization arising under existing tax regimes, any capital expenditure invested in the separation of gas and crude oil from a reservoir as well as any amount associated with gas delivery is cost-recoverable. Furthermore, all downstream APG utilization benefit from incentives specified in the Companies Income Tax Act, including a 3-year tax holiday and tax deductible interest on any loan taken for a gas project. Finally, in **Alberta**, when a company can successfully demonstrate through its required price forecast that APG-related investment is not economic, the company is eligible for a waiver on royalties to implement a utilization strategy.

As a general matter, APG monetization strategies such as reinjection and on-site power generation primarily benefit the operator and should therefore not be subsidized above and beyond providing favorable tax and royalty treatment comparable to that of other on-site investments. In such cases, the additional negative externality caused by flaring is properly internalized by the penalty. There are two justifications for preferring the penalty to a hypothetical subsidy here. First, in comparison to penalties, subsidies are, in practice, neither a cost-efficient nor a cost effective instrument. While many operators will require a subsidy to implement APG utilization strategies, many operators will be able to do so without any additional incentive. From a regulatory standpoint, the monitoring costs of designing a system that efficiently separates these two groups – and thereby does not provide an unnecessary benefit for behavior that operators would have done anyway without the subsidy – may be prohibitive. In contrast, a penalty imposed on flaring does not create unnecessary burdens or obligations. The only operators who pay the penalties will be the ones for whom the cost of implementing APG utilization technologies is higher than the penalty for flaring and venting. We note here that a penalty indexed on oil prices might be considered to ensure that even in case of high oil prices, the level of the penalty remains deterrent.

Second, imposing a penalty on flaring does not create any favorites when it comes to abatement technologies. Operators may choose a wide range of utilization strategies in response to a penalty, two of which have already been discussed (reinjection and on-site power generation). In comparison, a government that implements subsidies must decide which activities to subsidize, how much of each to subsidize, and also keep up to date with any possible

[47] CCSI, Angola APG Utilization Study, May 2014

new abatement techniques that may be developed organically by the market. Thus, without careful consideration and monitoring, the implementation of subsidies may lead to inefficiencies and corporate abuse.

The **Mexico** experience is particularly instructive in showing that sufficiently high penalties for flaring combined with a regulator that actively advises operators on technical modifications may accelerate the development of treatment equipment necessary for APG utilization (see Box 5).

Box 5: Pemex and penalties

Under the 2008 guidelines issued by Mexico's regulator (Comision Nacional de Hidrocarburos ("CNH")), PEMEX was required to present oil impact statements ("MIPs") in connection to its new projects while adhering to certain technical specifications, the non-compliance of which triggered sanctions. The MIPs are reviewed and approved by CNH to ensure reduction of flaring and the use of the most fitting technology.[48] During each phase of the review process, PEMEX was required under Article 12 of the guidelines to identify and evaluate feasible options for improvement of the production of the well, including the potential for facility repairs and the development of new facilities for the utilization of APG. To this end, the guidelines expressly required PEMEX to provide an economic evaluation and implementation strategy for reinjection and on-site power generation using the cost of utilization treatment equipment as a factor in its analysis.[49]

In 2008, PEMEX invested almost $3 billion in new well installation, gas treatment and handling equipment, and reinjection units. Reportedly, the company has also invested an additional $976 million in these efforts since then,[50] and continued to enter contracts for the construction of gas treatment plants.[51] Although more investment in gathering systems appears to be necessary in the coming years, the capital that PEMEX has already expended has contributed to a sharp reduction in gas flaring during the last several years.

The 2008 guidelines have since been superseded by those issued in 2016 by CNH. The effects of this new, more robust guidance document remain to be seen.

As opposed to the government of Mexico, the government of Kazakhstan proved inexperienced in his first attempt to limit flaring by imposing high penalties. In fact, that attempt resulted in oil companies threatening to abandon their wells (see Box 6).

---

[48] D. Biller, "CNH releases guidelines for E&P projects design," BN Americas (Dec. 2009), available at: http://www.bnamericas.com/en/news/oilandgas/CNH_releases_guidelines_for_E*P_projects_design?idioma=en

[49] Secretary of Energy, Resolution CNH.06.002/09 op. cit.

[50] J.S. Lozano, "Gas Utilization project in the Cantarell field, Mexico," PEMEX presentation to GGFR (Oct. 24, 2012).

[51] "Oil and Gas Journal Newsletter," 41 Oil and Gas Journal 108 (Nov. 1, 2010), available at: http://www.ogj.com/articles/print/volume-108/issue-41/regular-features/ogj-newsletter.html

Box 6: Kazakhstan's experience with anti-flaring policy.

In the early 2000's, Kazakhstan enacted amendments to its petroleum legislation prohibiting flaring. The amendments to Article 30-5 of the Law "On Petroleum" prohibited the development of oil and gas fields without utilization of APG, providing an exception in emergency situations or other exceptional cases. By introducing the provision, almost all oil-producers were immediately tagged as law-breakers and in just a few months the policy began to yield "undesired results."[52] In particular, petroleum companies received notifications requiring the companies to immediately commence the full utilization of APG or otherwise face a reduction of production volumes, termination of previously concluded contracts, and harsh penalties. In the months that followed, companies explained to the government the problems with assuming that flaring could be abated overnight. It became clear that the timetable for eliminating flaring would need to be expanded and that the government would need to take a more active role.[53]

Nonetheless, it may be the case that APG utilization provides positive externalities that are not sufficiently rewarded in the market. For example, as discussed in later sections, countries with low energy access might benefit from utilizing APG for public power generation. Similarly, in cases where selling APG abroad may bring positive externalities and access to capital into the country, subsidies may be a prudent and necessary regulatory instrument to help operators internalize a correlative social benefit associated with APG utilization and monetization. In response, such countries may decide to implement subsidies that reward operators at a level equivalent to the domestic price of energy. In fact the effectiveness of subsidies could be facilitated if the subsidies are linked to natural gas or LPG prices so that they do not overincentivize or underincentivize production. Alternatively, if the market is not producing a socially beneficial outcome, the state can seize unused APG as government property and implement the solution itself. Finally, to discourage APG from leaving the country where the regulator views domestic use as preferable, it can impose a tax on APG exports. The latter two solutions, in fact, have both been implemented in Angola and seem to have yielded positive results.

One innovative strategy toward penalties and fiscal stimuli is seen in **Russia**, where the relevant framework is established under Decree No. 344 of 2003 and Decree No. 1148 of 2012.[54] The former establishes a standard environmental fine for all air pollutants. For methane, the standard fine is 50 rubles per ton of methane produced when emissions are within the standard established by an air pollution permit and 250 rubles per ton of methane produced when emissions are outside the standard.[55] Decree No. 1148, which amends Decree No. 7 of 2009, sets a

---

[52] G. Nurakhment, "Gas Flaring & Venting: What Can Kazakhstan Learn From the Norwegian Experience?" University of Dundee (2014).

[53] CCSI, Kazakhstan APG Utilization Study, December 2014.

[54] Order of the Russian Federation N 344, "About Standards of the Payment for Emissions" (June 2003); Order of the Russian Federation N 1148, "About Features of Calculation of the Payment For Emissions" (Nov. 2012).

[55] Order of the Russian Federation N 344, op. cit.

multiplier for emissions of APG, such that flarers in 2013 were required to pay 12 times the standard environmental fine for APG emissions. For all years after 2013, this "multiplier" is 25.[56] Furthermore, the multiplier increases to 120 if the operator does not possess adequate monitoring equipment. The applicable multiplier is further increased or reduced based on the region where a field is located.[57]

The multiplier, however, is not applied in three instances. First, it is not applied for APG emissions that do not exceed the maximum permissible value.[58] Currently this value is equal to 5% of produced APG. For all APG emissions up to this level, the operator pays the standard environmental fine. Second, certain plots where cumulative production is under 1% of estimated recoverable reserve as well as the plots that are either within the 3 years of exceeding the maximum permissible value or within the years during which the cumulative production is under 5% of estimated recoverable reserves, whatever comes earlier.[59] Third, fields where annual APG volume is below 5 million cubic meters or non-hydrocarbon components represent less than 50% of the gas.[60]

In addition to setting the multiplier, Decree No. 1148 seeks to resolve the above problem by establishing a fiscal incentive for operators to invest in APG utilization projects. Operators who invest in such projects are allowed to subtract the costs of such investments from the applicable fines.[61] Eligible projects include gas pipelines, compressor stations, separation units, facilities producing electricity/heat, and reinjection equipment. Also included is the cost of equity for investors participating in joint projects with operators who invest in such equipment.

The Decree also allows operators of multiple fields to aggregate countrywide APG utilization vis-à-vis flaring for purposes of calculating the 5% maximum permissible target.[62] These provisions help ensure that investment in utilization projects are most efficiently directed to fields where they are most viable.

Although more time is necessary to fully evaluate the effects of Decree 1148 on flaring in Russia, early signs are promising.[63] On the surface, a flat 5% maximum permissible value for flaring does appear to be somewhat as a blunt instrument. One might wonder if it would be more effective to define this value on a more case-by-case basis, particularly given the substantial heterogeneity in geological and geographic conditions between the various Russian fields, which likely creates diversity in the extent to which a particular field faces favorable conditions to minimize flaring. That said, the aggregation option specified in Article 11 is likely to somewhat

---

[56] Art. 2, Order of the Russian Federation N 1148, op. cit.
[57] Art. 5, Order of the Russian Federation N 1148, op. cit.
[58] Art. 2, Order of the Russian Federation N 1148, op. cit.
[59] Art. 2, Order of the Russian Federation N 1148, op. cit.
[60] Art. 6, Order of the Russian Federation N 1148, op. cit.
[61] Art. 8, Order of the Russian Federation N 1148, op. cit.
[62] Arts. 11-15, Order of the Russian Federation N 1148, op. cit.
[63] CCSI, Russia APG Utilization Study, Forthcoming 2016.

mitigate the impact of the blunt instrument, since investors can simply bundle disparate fields to account for the diversity. Moreover, the advantage of a blunt instrument stems from the increased predictability that arrives with a flat 5% limit on non-multiplied emission fees (rather than a limit taking into account the circumstances of each field).

The most innovative part of the Russian apparatus, however, is the multiplier itself. This mechanism effectively charges distinct flaring rates based on the level of flaring that an operator or company commits. This sort of pricing model, as opposed to a flat penalty, is more difficult to calibrate to the social cost of carbon, as economic theory demands. That said, the model does ensure that those operators who produce the highest quantity of APG, and therefore likely stand to benefit the most from more utilization, are punished the most for choosing to flare.

As a final note, it is not fully clear whether the Article 5 multiplier, which is set at 120 for operators that do not possess adequate monitoring equipment, can actually be enforced. After all, if adequate monitoring equipment is not available at a field, there is no reliable mechanism for determining how much APG is actually flared and therefore subject to penalty. One might wonder whether it would be more effective to take a more drastic measure against flarers possessing inadequate monitoring equipment—such as a temporary suspension of operations.

Note on Clean Development Mechanism

Countries seeking to reduce flaring might also consider measures to utilize the "Clean Development Mechanism" ("CDM"), an instrument contained in Article 12 of the Kyoto Protocol that was designed to provide governments and companies in industrialized countries to invest in GHG reduction projects in developing countries.[64] The CDM operates by enabling developed nations to abate emissions that count toward Kyoto goals by investing in carbon-offset projects occurring in developing nations. Thus, under the CDM, a developing country that seeks to convert a flaring regime to an utilization regime can have the project financed by an investor of developed nation – one that possesses an incentive to invest in such projects as a way to meet emission reduction targets imposed by the developed nation.

Although the CDM has served as a powerful GHG reduction mechanism for developing countries in Asian countries such as China and India, it has been less successfully utilized in the African countries where flaring is a problem.[65] The key to attracting CDM investors is highly linked to the enablement of a regulatory environment that actively recognizes the CDM. Steps that developing nations may consider for attracting CDM-based investment include the implementation of clear procedures and criteria for CDM projects, explicitly delegating oversight of CDM projects to a government agency, and providing express provisions and protocol for the

---

[64] D.S. Olawuyi, "Beautifying Africa For the Clean Development Mechanism: legal and Institutional Issues Considered," 17 Afr. J. Int'l & Comp. L. 270 (2009).

[65] See A. Silayan, "Equitable Distribution of CDM Projects Among Developing Countries" HWWA Report 255, Hamburg, pp. 1.

transfer of certified emission reduction credits ("CERs") to the CDM investor.[66]

One notable challenge to countries seeking to secure funding under the CDM centers around the concept of "additionality," the requirement that the CDM only provides carbon credits to projects that could not be built without the extra financial support of the CDM. To put another way, under the CDM, "projects that would be built anyway, that are business-as-usual, should not get carbon credits because such projects generate credits that are not based on actual emissions reductions."[67]

Therefore for countries where flaring is prevalent, it is critical to ensure that CDM-funded projects are in fact additional. First, such allocations may siphon funds from more deserving APG utilization projects that are occurring in the country (i.e. those projects which would not succeed in the absence of CDM revenue). Furthermore, it should be noted that in recent years, there has been increased attention on the part of the CDM Executive Board and environmentalists directed toward the prevalence of CDM projects that are non-additional or not contributing to sustainable development.[68] Given an observed lack of effectiveness, CDMs might be totally overhauled.[69]

In the meanwhile, countries that facilitate the funding of non-additional projects under the CDM may undermine their credibility and thereby jeopardize the funding of future projects. That said, operators should make best efforts to demonstrate the presence of additionality where an APG utilization project is dependent on CER revenue. In demonstrating additionality, operators may rely on prevailing practices in the industry, required rates of return for similar projects, prevailing electricity and natural gas prices, and other associated investment costs.[70]

Key Takeaway from Recommendation Three

- Negative externalities produced by flaring are properly internalized by a rigorously-enforced No-flaring policy assorted with high penalties making investment in APG utilization worthwhile.
- However positive externalities produced by broadly distributed APG utilization technologies

[66] D.S. Olawuyi, "Beautifying Africa For the Clean Development Mechanism: legal and Institutional Issues Considered," op. cit.

[67] Carbon Market Watch, "Intro to the CDM," available at: http://carbonmarketwatch.org/learn-about-carbon-markets/intro-to-the-cdm/.

[68] See e.g. Z. Hausfather, "Kyoto Accord Compliance Markets: Can Emission Trading Offsets Work?," Yale Climate Connections (Aug. 7, 2008), available at: http://www.yaleclimateconnections.org/2008/08/common-climate-misconceptions-kyoto-accord-compliance-markets-can-emission-trading-offsets-work/.

[69] Climate Observer, "COP21 and the Clean Development Mechanism: Deciding the Future of International Carbon Credits," ICCG International Climate Policy and Carbon Markets Series (July 29, 2015), http://climateobserver.org/cop21-and-the-clean-development-mechanism-deciding-the-future-of-international-carbon-credits/.

[70] See e.g Afam Combined Cycle Gas Turbine Power Project, "Project design document form for CDM project activities," op. cit.

may not be. Thus, on-site utilization strategies should not benefit from subsidies, but countries may choose to extend subsidies for off-site technologies such as APG for public power generation.

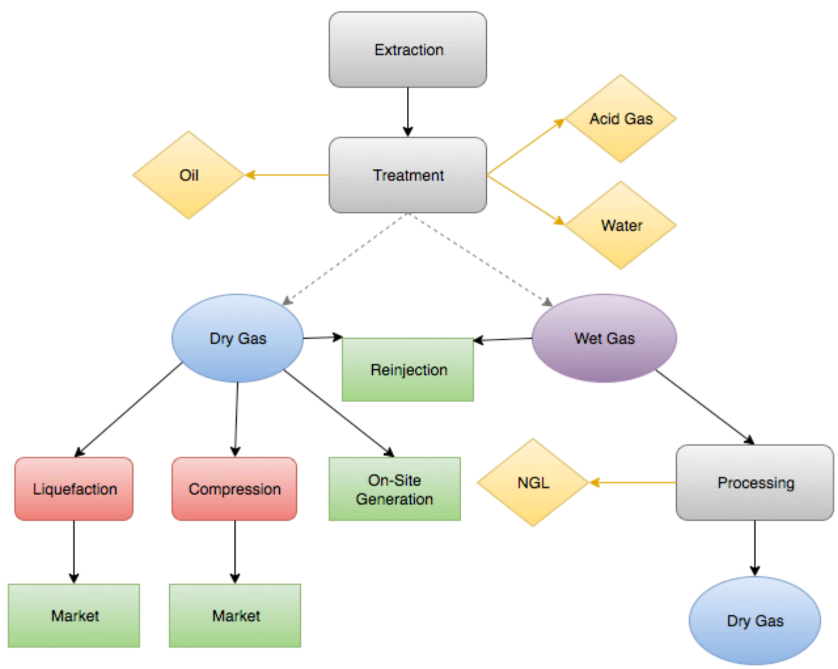
- APG projects could be well suited for CDM but countries and operators should work together to ensure that CDM enables "additionality".

D. Recommendation Four

To ensure economically rational APG utilization strategies, develop reliable technical and commercial understanding at each phase of the APG value chain to inform the requirements for APG use; possibly appoint an expert panel composed of representatives from the Industry, Flaring Experts and Regulators to identify the various points along the production process that lend themselves to better optimization in view of a more meaningful use of APG

Overview of APG Value Chain

Figure 4: Overview of the APG Value chain



Source: Authors

A schematic diagram depicting the basic APG supply chain is shown in Figure 4. Later sections will offer separate treatment to various points in the supply chain, but for clarity this section will provide a broad overview. The first step in any APG utilization scheme is "**Extraction**," in which the APG is removed from the well, alongside oil. After **Extraction** is complete, the next step involves separating the natural gas from the oil and from other impurities. This step, which for simplicity we refer to as "**Treatment**," is necessary to prevent corrosion and other problems that may arise in downstream handling equipment. While some of the needed treatment can be accomplished at or near the wellhead, it will mostly occur at a Gas Treatment Plant ("GTP"), where the APG is transported through a network of small-diameter, low-pressure pipes known as "gathering" pipelines.

After **Treatment** has completed, the next stage in the APG utilization supply chain will depend on the chemical composition of the APG. If the APG is a "dry gas" – in the sense that it contains predominantly methane – the next stage can be **Reinjection**, **On-Site Generation**,

Compression, or **Liquefaction**.

If the APG is "wet", in the sense that it contains a substantial amount of NGL, the next step after **Treatment** is either **Reinjection** or **Processing**. In **Processing**, NGL is separated from the methane component of the APG to be sold separately.

Broadly, the four primary APG utilization methods can be grouped into two categories. ***On-Site Utilization*** techniques include **Reinjection** and **On-Site Generation**. These techniques primarily benefit the operator who, in deploying them, avoids paying penalties associated with flaring and also potentially enjoys operational efficiency gains in its business. ***Monetization*** techniques, on the other hand, include those discussed in the **Compression** and **Liquefaction** sections. Such techniques may generate positive externalities for society and are also likely to require substantial midstream infrastructural investment to link production sites to the point of sale.

1. Treatment & Processing

There are a many ways to treat and process the gas flow but here a generalized typical configuration is described.

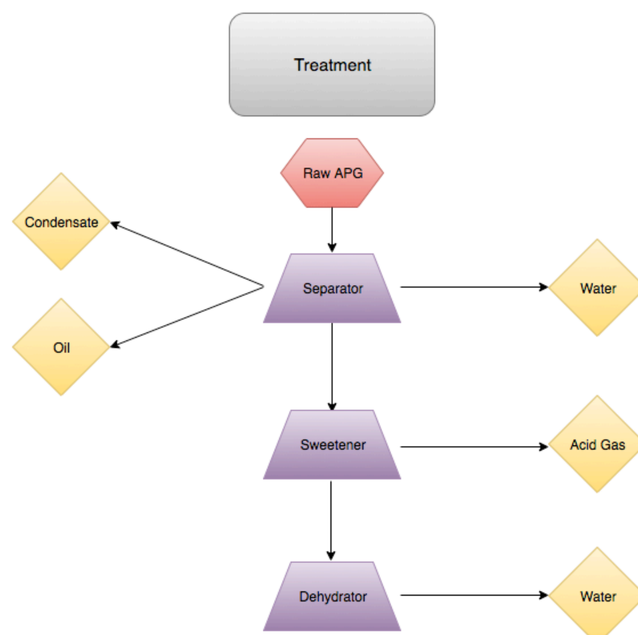
a) Treatment

A schematic diagram of the basic process for treating natural gas is shown in Figure 5. Broadly, this stage consists of several steps to isolate the APG from impurities.

In the *Separator* phase, heaters and scrubbers are used to prevent the temperature of the APG from dropping too low and remove large-particle impurities, respectively. Second, the APG is separated from the oil in which it is dissolved.

In the *Sweetener* phase, non-hydrocarbon molecules, carbon dioxide and hydrogen sulfide (H2S) contained in the APG, known as "acid gases" are removed.[71] This step is necessary because acid gas can be "extremely harmful, even lethal, and very corrosive"

Figure 5: Treatment



Source: Authors

[71] A sweetening unit utilizes a set of organic compounds, in this case called "amines," to absorb acid gas from the APG steam. (Source: M. Beychok, "Amine gas treating," The Encyclopedia of Earth (2011), available at: http://www.eoearth.org/view/article/170697/)

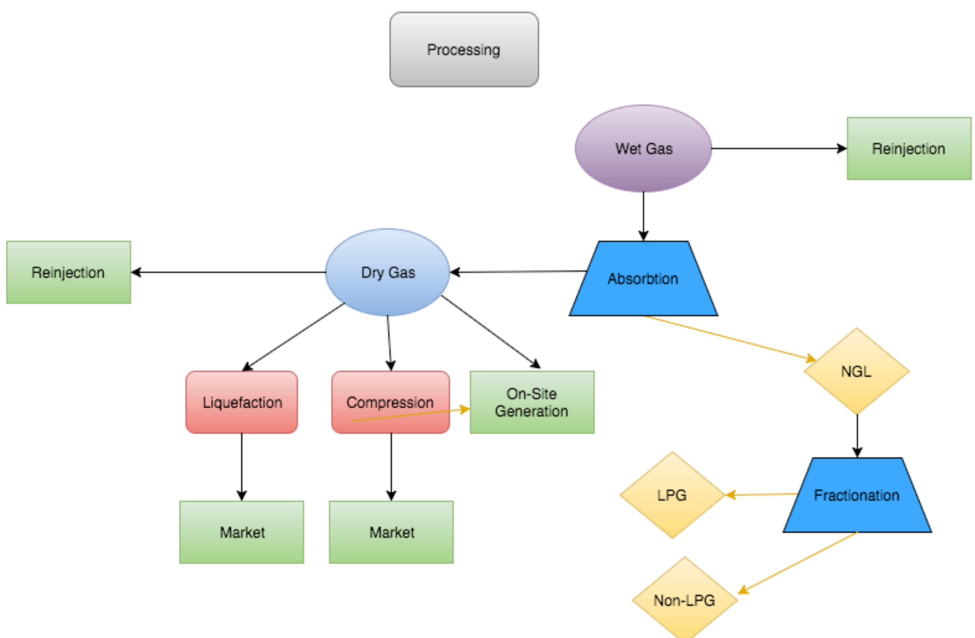
downstream.[72]

In the *Dehydrator* phase, excess water that was not removed during the *Separator* phase is properly removed.

The basic Treatment processing described above – Separation, Sweetening, and Dehydration – will almost always be necessary for the utilization of APG, although the particular equipment used may differ depending on the chemical composition of the gas at the point of extraction. Furthermore, even at fields where flaring is the prevalent outlet for APG, at least a portion of the required equipment should already exist. For example, an operator of an oil field will require a Separator to separate the desired petroleum components, even if the operator is flaring the APG. Similarly, because typically the amount of acid gas that an operator can flare under existing regulations is often very low,[73] an operator conducting flaring may already possess a Sweetener on-site to remove the CO_2 and H_2S components from the waste gas before redirecting it to the flare stack. Still, an operator that desires to convert a flaring operation to an APG utilization operation may find that this Treatment equipment will need to be enhanced or upgraded in order to complete the conversion.[74]

b) Processing

Figure 6: Processing



Source: Authors

[72] "How Do You Process Natural Gas?," Croft Production Systems (2014), available at: http://www.croftsystems.net/blog/how-do-you-process-natural-gas.

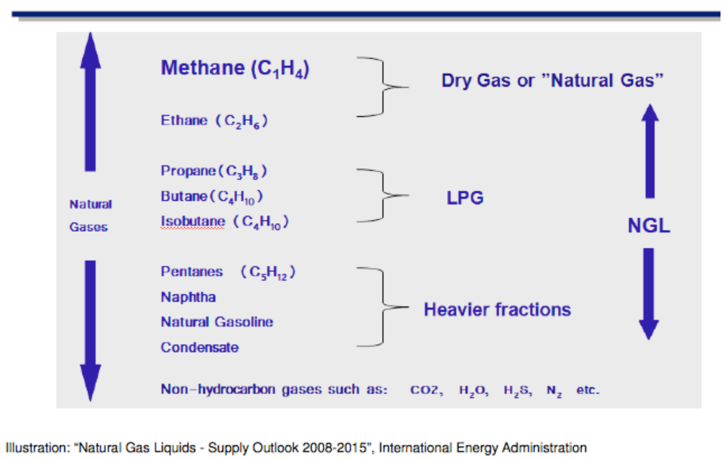
[73] M. Beychok, "Amine gas treating," op. cit.

[74] E.g. Spetco, "Gas Compression & Re-Injection Facility," available at: http://www.spetco.com/gas-compression-and-re-injection-facility.htm.

Following Treatment, if the APG produced is "wet", the APG's substantial NGLs must be separated for sale into liquids markets as discussed in the overview.

Although there are number of ways to separate the NGL from the "natural gas" (mostly composed of methane) component of the APG, the most common method is know as "cryogenic expansion," which relies upon the differences in the component boiling point pressures and temperatures.[75] The "natural gas" is then sent downstream (discussed in later sections), and the NGL is delivered to a fractionation facility where NGLs are separated into their individual components. NGLs have all different markets and uses. After the processing has completed, the NGLs can be transported in liquid forms in refrigerated ships, pipelines, and trucks. Those classified as liquid petroleum gases (LPGs) composed mostly of propane and to a lesser extent butane are most often used as heating and engine fuels in homes and industry. The other NGL components are sent to the petrochemical industries as feedstock for further downstream processing (see Figures 7 and 8).

Figure 7: Difference between NGL and LPG

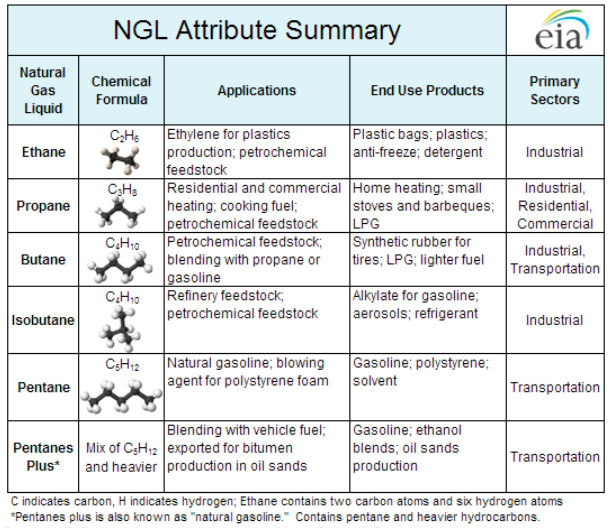


Source: "Natural Gas Liquids - Supply Outlook 2008-2015", International Energy Administration[76]

[75] The wet APG passes through a heat exchanger, where it is cooled by a counter-flowing methane gas to a temperature of -34 °C, causing the heavier NGL components to become liquid. The remaining gas is then siphoned through a valve that causes an even sharper drop in temperature to around -107 °C, which separates the ethane components from the methane, which is now the last remaining hydrocarbon in gaseous state (Source: International Human Resources Development Corporation, Midstream Gas Module op. cit.)

[76] International Energy Administration, "Natural Gas Liquids - Supply Outlook 2008-2015," (2010), available at: https://www.iea.org/publications/freepublications/publication/natural-gas-liquids---supply-outlook-2008-2015.html

Figure 8: NGL and their applications



NGL Attribute Summary				eia
Natural Gas Liquid	**Chemical Formula**	**Applications**	**End Use Products**	**Primary Sectors**
Ethane	C_2H_6	Ethylene for plastics production; petrochemical feedstock	Plastic bags; plastics; anti-freeze; detergent	Industrial
Propane	C_3H_8	Residential and commercial heating; cooking fuel; petrochemical feedstock	Home heating; small stoves and barbeques; LPG	Industrial, Residential, Commercial
Butane	C_4H_{10}	Petrochemical feedstock; blending with propane or gasoline	Synthetic rubber for tires; LPG; lighter fuel	Industrial, Transportation
Isobutane	C_4H_{10}	Refinery feedstock; petrochemical feedstock	Alkylate for gasoline; aerosols; refrigerant	Industrial
Pentane	C_5H_{12}	Natural gasoline; blowing agent for polystyrene foam	Gasoline; polystyrene; solvent	Transportation
Pentanes Plus*	Mix of C_5H_{12} and heavier	Blending with vehicle fuel; exported for bitumen production in oil sands	Gasoline; ethanol blends; oil sands production	Transportation

C indicates carbon, H indicates hydrogen; Ethane contains two carbon atoms and six hydrogen atoms
*Pentanes plus is also known as "natural gasoline." Contains pentane and heavier hydrocarbons.

Source: EIA[77]

Production costs for NGL are generally low, so NGL does not typically necessitate a large demand and can be used domestically for petrochemical plants, burned for space heat and cooking, and blended into vehicle fuel. For instance the **Nigerian** LNG consortium, NLNG, signed Sales and Purchase Agreements (SPAs) with off-takers (all Nigerian companies) to deliver 150,000 tons of LPG into the Nigerian market annually in 2007.[78]

Still, NGL components typically are in small quantities in APG so their exploitation is not enough to solve the APG use question and dry gas use options should also be explored as discussed in the sections below. NGLs however generally have a higher value than "natural gas" and their profitability can help the economics of the exploitation of the dry gas.

2. *On-Site Utilization Techniques*

The primary on-site APG utilization techniques are **Reinjection** and **On-Site Power Generation**, each of which is discussed in the sections that follow. It should be noted, however, that neither outlet will serve as a comprehensive utilization technique because the volume of APG produced by most wells will exceed the amount that can be utilized in reinjection or on-site generation. Thus in the long-term, as distributional infrastructure is made more widely available, on-site utilization is likely to be used in combination with selling the APG in the market. In those circumstances, where both on-site utilization and monetization are made possible, the operator is more likely to utilize on-site when the price of APG on the open markets is low, particularly in comparison to diesel cost and power from the grid. **In the short term, on-site utilization can**

[77] EIA, http://www.eia.gov/todayinenergy/detail.cfm?id=5930
[78] CCSI, Nigeria APG Utilization Study Profile, May 2014

serve as an important transitional outlet to abate a portion of otherwise flared APG while operators await the construction of distributional infrastructure.

a) Reinjection

APG components are eligible for reinjection in three primary instances: as dry gas that has undergone **Treatment**, as wet gas that has undergone **Treatment**, or as dry methane that has been separated from NGL during **Processing**. Additionally, the non-hydrocarbon gases produced as a byproduct of the various treatment phases such as the *sweetener* phase may also be reinjected. To fully understand how an operator might employ APG products to enhance oil recovery and develop the proper regulatory response, it is necessary to provide a brief overview of the well life cycle. proper regulatory response, it is necessary to provide a brief overview of the well life cycle.

As a general matter, there are three stages of oil field development: primary recovery, secondary recovery, and tertiary recovery. While these three types of recovery were traditionally applied sequentially, advanced reservoir management techniques increasingly follow an integrated approach designed to take advantage of each reservoir's bespoke characteristics. [79] During *primary recovery*, oil is produced using the natural pressure of the reservoir as the driving force to push oil to the surface, [80] over time the reservoir pressure depletes and is no longer sufficient to force the crude oil to the surface and the amount recovered may be as low as 10 % of a reservoir's original oil in place.[81] *Secondary recovery* techniques are employed to prevent such drops in pressure and occurs most commonly through "water flood," a technique used on a very large scale in Saudi Arabia where sea water is pumped into the country's very large reservoirs. In a number of cases, however, "gas flood" may be the preferred secondary mechanism instead of water flood. Here, natural gas is injected directly into the gas cap of the formation to maintain reservoir pressure and thereby allow for additional recovery.[82] Secondary recovery projects typically produce an additional 10% to 20% of the original in-place oil.[83] The oil that would otherwise remain in the well if recovery were limited to primary and secondary recovery is blocked from migrating to the well bore by the oil's high viscosity or because of irregular fault-lines in the reservoir.[84]

---

[79] Schlumberger is experimenting and adopting new technologies to incorporate EOR into field management practices early in the development of the field rather than leaving it until the end-of-life of a field. (source: http://www.slb.com/resources/publications/industry_articles/software/201503_eor_petroleum_review.aspx)

[80] In certain very undersaturated oil reservoirs, gas injection techniques may be utilized at the beginning of the production process to increase oil recovery. Rigzone, "How Does Gas Injection Work," available at: http://www.rigzone.com/training/insight.asp?insight_id=345&c_id=4.

[81] "Enhanced Oil Recovery," Enhance Energy Inc., available at: http://www.enhanceenergy.com/pdf/Background/enhanced_oil_recovery.pdf.

[82] Rigzone, "How Does Gas Injection Work," op cit.

[83] MidCon Energy, "Oil Recovery Overview," available at: http://www.midconenergypartners.com/oil-recovery-overview.php.

[84] J.G. Speight, *Handbook of Offshore Oil and Gas Operations* (1st ed. 2015), page 174.

Tertiary or *enhanced oil recovery* (EOR) mechanisms aim to recover part of this usually large share of hydrocarbons by changing the actual properties of the hydrocarbons and/or the makeup of the reservoir.[85] There are three main types of tertiary recovery mechanisms: chemical flooding, thermal recovery, or the injection of a gas that is miscible with the oil in place. In theory, APG reinjection can be used to perform the latter function, which involves injecting gases into the reservoir to dissolve in the oil, thereby decreasing viscosity and increasing production.[86] Yet, to maximize its effectiveness, EOR must be preceded by in-depth analysis of the hydrocarbon mix and of the reservoir's topology with a view toward identifying how the various relevant parameters can be most effectively modified through the proper type gaseous or liquid ("chemical" or "polymer") additions into the mix[87].

Depending on the composition and processing stage of the APG, the operator can analyze which of a variety of APG reinjection strategies would come closest to meeting the optimal parameters for. First, APG that is already dry gas when it has been removed from the well can be reinjected as is. Second, APG containing substantial NGL and/or non- hydrocarbon (N2 [Nitrogen gas], CO2, H2S) components can also be reinjected as is. For instance by mid 2016, Chevron will take the final decision regarding expanding its **Kazakh** Tengiz oil field by reinjecting sulfur-laden gas back into the rocks to produce an additional 250,000 to 300,000 barrels a day for a cost of $40 billon.[88] Third, APG containing substantial NGL and/or non-hydrocarbon gas components can be separated from those, and the dry gas outputs can be reinjected. Fourth, APG containing substantial NGL and/or non-hydrocarbon gas components can be separated from those and the non- hydrocarbon gas components can be reinjected. Of these, the fourth reinjection scenario is a particularly attractive one, in part because CO_2 is currently the most popular tertiary agent in oil fields[89] and in part because there are few alternative utilization options for non-hydrocarbon gases. Thus, reinjection can serve as a permanent disposal mechanism for sour gas when monetization of other APG products is possible. Where there is a choice between reinjecting dry gas and reinjecting sour gas, it therefore makes the most economic sense to reinject sour gas.

---

[85] Rigzone, "What is EOR, and How Does It Work?,"available at : http://www.rigzone.com/training/insight.asp?insight_id=313.

[86] Rigzone, "What is EOR, and How Does It Work?,"op. cit.

[87] "All EOR projects begin with an analysis of the nature, location, and causes of residual oil saturations (S_{or}) that remain after primary and/or secondary recovery operations. The main factors that control the value of S_{or} are pore geometry, rock wettability, and the properties of the displaced (oil) and displacing (injected) fluids. Fluid properties of particular interest are interfacial tension, viscosity, and density. In combination with the heterogeneity of the reservoir, these properties result in the overall recovery (E_R) for any recovery scheme.". Retrieved from the open access resource for the petroleum geosciences community maintained by the American Association of Petroleum Geologists (AAPG) at http://wiki.aapg.org/Enhanced_oil_recovery.

[88] Rigzone, "Chevron Deadline Nears For $40B Bet On Next Decade's Oil," available at: http://www.rigzone.com/news/oil_gas/a/145412/Chevron_Deadline_Nears_For_40B_Bet_On_Next_Decades_Oil

[89] L.S. Melzer, "Carbon Dioxide Enhanced Oil Recovery: Factors Involved in Adding Carbon Capture, Utilization and Storage to Enhanced Oil Recovery," Melzer Consulting (Feb. 2012), available at: http://neori.org/Melzer_CO2EOR_CCUS_Feb2012.pdf.

How regulators can promote reduced flaring through a greater use of APG in secondary and tertiary recovery is an economic and technical question that will be answered differently in different reservoirs. As said, the industry trend is toward bespoke approaches to reservoir management to maximize economically justified recovery under the local constraints in light of monetization opportunities. As observed by the AAPG "all current EOR techniques are much more expensive to implement than normal secondary water injection projects. Therefore, the amount of oil that can ultimately be recovered by existing EOR techniques is directly related to the price of crude oil."[90] EOR can add as much as $ 20 per barrel recovered although EOR industry leaders such as EOG Resources have been able to reduce such cost in half or more in certain plays[91]. The best approach for regulators therefore is to stay clear from micro-management of reservoirs through such approaches as mandating technical choices and, instead, to tilt the playing field in support of APG reinjection by levying penalties on flaring. In this manner, the external environmental cost of flaring can be internalized in the bespoke decisions that reservoir engineers and managers will take. By contrast, if the penalty for flaring is not high and there is no alternative for APG disposal mechanism immediately available, the operator will choose to flare rather than switch from water flooding to APG gas flooding for secondary recovery or will neglect EOR injection possibilities that will not appear as economically justified.

When reducing flaring is the objective, investments in reinjection can generate substantial returns on flaring abatement. For example, in 2008, the **Mexican** state-owned oil company Pemex invested about $3 billion in new well installation, desalination facilities, and dehydration plants designed to enhance its decreasing oil production. At the same time, gas flaring reduction turbo-compressors, gas reinjection equipment, and a nitrogen recovery unit were installed at the Ciudad Pemex Tabasco Gas Processing Center. Largely due to this investment, APG utilization in Mexico increased from 74% in 2008 to 98% in 2012.

Reinjection as an abatement mechanism is limited by two factors. First, the amount of APG that can be reinjected is limited by the injection capacity of the well, which is typically lower than the withdrawal rate.[92] Second, as demonstrated in **Indonesia**, reinjection of APG products in older and heavier fields is often not effective or economic. [93]

Nonetheless, reinjection can also serve as a powerful transitional strategy as the country develops infrastructure necessary to pursue other utilization options. In 2012, 68% of natural gas produced in the **Republic of the Congo** was reinjected while 16% was flared or vented, representing a 30% decrease over the previous decade. [94] Additionally, 15% of its natural gas was

---

[90] AAPG, *op.cit.*

[91] Housley Carr, "Let It Flow - The Potential for Enhanced Oil Recovery in Shale Plays", RBS Energy LLC, June 7, 2016.

[92] U.S. Department of Energy, "The Basics of Underground Gas Storage," Natural Gas Reports (Nov. 16, 2015), available at: https://www.eia.gov/naturalgas/storage/basics/.

[93] CCSI, Indonesia APG Utilization Study, July 2014

[94] Energy Information Administration, "Congo (Brazzaville" (Jan. 29, 2014), available at: http://www.eia.gov/beta/international/analysis.cfm?iso=COG

used domestically,[95] mostly for power generation, a figure that represents an exponential increase over the last decade, and is due in large part to a 2008 decision by Eni to construct two gas-fired electric power stations.[96] The Republic of the Congo's experience suggests that the development of reinjection technology has the potential to lead to more comprehensive flaring reduction efforts down the road.

b) On-Site Generation

Use of APG in power generation on-site can prove to be fruitful abatement option, especially where the APG cannot be delivered to a gas pipeline, is too corrosive, or is too small a quantity to justify long-distance transport. Generally, about a third to one half of the cost of extracting oil at the well is tied to the cost of energy expended to recover that oil.[97] In many cases, this energy cost is so high that it may render the extraction of some oil in the well uneconomical. Conversion of flaring operations to on-site generation can therefore produce financial gains both directly by inducing energy cost savings for the operator and indirectly by increasing the economics of oil extraction. In a 2008 by the **California** state government, it found that such efforts can provide a payback in as little as 2.5 months and result in a financial benefit to the operator of as high as $2.7 million per year.[98] Still, although in low-APG volume fields local generation may amount to full APG utilization, in typical cases the field will only require 30% of the power that APG could generate.[99] Local generation will therefore usually need to be combined with other utilization strategies. For example, at the **Jubilee field in Ghana**, the target APG production level is 120 million standard cubic feet (mmscfd) per day. Of this, around 20 mmscfd are used for on-site power generation, 30 mmscfd are used for reinjection, and the remaining amount is brought onshore.[100] This system ensures that the needs of the facility are accounted for before the APG is implemented in domestic use.

Use of APG for on-site power generation is likely to be particularly attractive for operators who otherwise generate electricity through heavy-duty diesel engines. As stated by one observer, "diesel fuel is in constant high demand at shale gas and oil well sites...creating economic, environmental and logistical problems for shale gas and oil producers."[101] Compared to diesel, use of APG has higher initial capital expenditure costs but lower long-term operational costs. One place where this effect has been particularly pronounced has been in the **North Dakota**, where "diesel fuel must be trucked over many miles to supply the needs of the oil producers in

---

[95] CCSI, Republic of Congo APG Utilization Study, May 2014

[96] Energy Information Administration, "Congo (Brazzaville" (Jan. 29, 2014), available at: http://www.eia.gov/beta/international/analysis.cfm?iso=COG

[97] California Oil Producers Electric Cooperative, "Offgases Project Oil-Field Flare Gas Electricity Systems," Public Interest Energy Research Program (Dec. 2008), available at: http://www.energy.ca.gov/2008publications/CEC-500-2008-084/CEC-500-2008-084.PDF

[98] J.G. Speight, *Handbook of Offshore Oil and Gas Operation*s, op. cit.

[99] CCSI, Overview: Associated Petroleum Gas, May 2014

[100] CCSI, Ghana APG Utilization Study, September 2015

[101] R.J. Roby et. al, "Low Emissions Microgrid Power Fueled by Bakken Flare Gas," LPP Combustion, LLC (July 2014).

the Bakken basin…[at a cost that can exceed] $5.00 per gallon."[102] Some success has also been seen in **Russia**, where 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. Typically, the solution was to use localized diesel-powered plants. Recently, 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 diesel-fired power plants and the fuel to run them.[103]

The business case for on-site generation when the operator can source from the grid will stem from either an expensive or an unreliable grid. For instance, in traditional oil-producing regions of **Russia**, power needs are typically met with electricity from the grid. In Western Siberia, in the Khanty-Mansi Autonomous Okrug, many fields are supplied with electricity by the Urals branch of the United Energy System.[104] However, as the Russian power sector has slowly liberalized electricity prices have increased (by up to 20% in some areas), making APG power plants a more viable alternative.[105] These plants either partially or fully offset the costs of grid obtained electricity in areas with old or constrained electricity distribution systems. For instance, 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,[106] when previously, the field had been supplied by electricity from the grid.[107]

Even when there is no business case for on-site generation, it may indirectly result in increased energy access. If operators generate local electricity by utilizing APG, they will likely use less electricity generated by public utilities and third party IPPs. In such cases, resources that would otherwise be used to provide power to operators would be redirected by public utilities to benefit other consumers. Such gains would be particularly high in instances where the utility has adopted net metering technology,[108] which would allow the operator to seamlessly sell surplus generation back to the grid.

Technically, there are a number of ways in which natural gas may be used on-site to generate electricity. A few of the basic methods that may be employed include fuel cells, gas-fired reciprocating engines and industrial-gas fired turbines.[(See Annex A)]

The use of NGL in on-site power generation has also recently become an option with the development of "Lean, Premixed, Prevaporized" ("LPP") combustion technology. LPP consists of a gas turbine and fuel conditioning system that takes NGL, vaporizes them and blends them with

---

102 R.J. Roby et. al, "Low Emissions Microgrid Power Fueled by Bakken Flare Gas," op. cit.

103 Carbon Limits, *Associated Petroleum Gas Flaring Study for Russia, Kazakhstan, Turkmenistan and Azerbaijan*, pp 12-13

104 Carbon Limits, p 23

105 Carbon Limits, p 23

106 Carbon Limits, p 23

107 Carbon Limits, p 23

108 Net metering is a tool that permits an individual who installs energy equipment on their property to sell excess electricity back to the grid. V.J. Faden, "Net Metering of Renewable Energy: How Traditional Electricity Suppliers Fight to Keep You in the Dark," 10 Widener J. Pub. L. 109 (2000-2001).

nitrogen to create gas that is burned in a turbine to generate electricity.[109] Such strategies have proven especially important for **Bakken flare gas**, which is rich in NGLs.[110]

Another regulatory action that may encourage this APG strategy is the use of "operational clustering." By encouraging operators located in close proximity to gather APG at a centralized location, regulators can substantially improve the economics of APG-based local generation. Operational clustering can be used to encourage any form of APG utilization, but it arguably possesses the most promise under the local generation strategy. The reason is that there is a high initial capital cost imposed on operators that can easily be reduced through economies of scale. Regulators can accelerate the process of operational clustering by conducting research on cost savings of shared local generation among operators.

One concern with operational clustering involves the question of who will operate the centralized facility. To prevent favoritism, regulators should require the centralized service provider to be an independent agency or corporation unaffiliated with any of the operators. If the economics of operational clustering in local generation are attractive, companies will be willing to provide such services for a fee determined in the market. Since operators are still able to receive energy from other sources, these centralized local generators will not exert monopolistic behavior and so regulation of their rates will not be necessary.

3. Monetization

Although there are a variety of considerations and mechanisms associated with monetizing APG, in general the success of such efforts will depend on two factors: (1) the availability of distributional channels that can access markets for APG, and (2) the level of demand for APG in those markets. Countries possessing a strong domestic market for natural gas and an existing pipeline transportation network are best positioned to monetize currently flared APG through **Compression**.

Where domestic demand is not high enough to render APG marketing or pipeline investment economically attractive to investors, access to international markets can fill in the gap. **Norway** in particular has a highly robust network of national and international pipelines that allows it to reach countries across the European continent. As of 2014, Norway supplied 20% of Europe's natural gas needs,[111] a reality contributing to its exceptionally low APG flaring rates. Still, even in such countries, downward fluctuations in the market price of natural gas or lack of gathering infrastructure at operating facilities can negatively alter the economics of APG utilization, so governments should take care to implement fiscal and legal frameworks to deter operators under

---

[109] P.C. Miller, "LPP Combustion Demonstrates Gas Capture Technology in the Bakken," *The Bakken Magazine* (Oct. 8, 2014), available at: http://thebakken.com/articles/826/lpp-combustion-demonstrates-gas-capture-technology-in-the-bakken

[110] P.C. Miller, "LPP Combustion Demonstrates Gas Capture Technology in the Bakken," op. cit.

[111] U.S. Energy Information Administration, "Norway Supplies More than 20% of Europe's Natural Gas Needs" (May 16, 2014), available at: https://www.eia.gov/todayinenergy/detail.cfm?id=16311

financial stress from turning to flaring as a solution. In **Canada**, for example, APG flaring has increased during recent years despite the country's strong domestic market for natural gas across retail and industrial sectors, largely due to changes in the price of natural gas and an uptick in heavy sands oil production.[112] Similarly, in **North Dakota**, until 2014 flaring rates remained around 30% despite operators' proximity to the United States gas market, a troubling reality largely driven by a lack of intra-state pipelines, a weak regulatory framework and a low financial capacity on the part of operators to internalize the costs of the necessary facilities.[113]

In countries where domestic demand is low and international markets are inaccessible by pipeline, the economics of marketing APG will depend largely on the ability of companies to transport APG by water. This issue is discussed in the **Liquefaction** section. LNG-based transport is highly capital intensive and will only be justifiable where there is sufficiently high gas volume and where LNG producers manage to secure customers and lock them in strong LNG sales purchase agreements before the start of the production. Nonetheless, liquefaction can prove to be a powerful abatement strategy, particularly in countries that possess substantial natural gas reserves independently of APG. In **Nigeria**, for example, producers successfully converted some 104 billion cubic meters of APG to LNG for export over the period spanning from 1999 to 2012 and the LNG is also supplied by non-associated gas. [114] Similarly, companies in **Equatorial Guinea** recently completed an LNG project in Malabo whose first train was designed to process 3 trillion cubic feet of APG from the Alba field and a second train and future LNG trains would process APG and non-associated gas from fields in Equatorial Guinea and neighboring countries. [115] In Angola, the LNG facility runs mainly on APG and receives greater than 1bcf of natural gas per day from 7 offshore blocks.[116]

a) Compression to Pipeline for Power Generation

Flared gas for power generation may be an attractive utilization option, particularly where electricity access rates are low. Given the centrality of energy access as a key component of overall economic growth and social welfare,[117] there is a strong argument that governments of these nations should incentivize APG use in power generation, particularly in instances where a perceived lack of financial return is likely to discourage investors from pursuing such projects. **Nigeria**, for instance, where energy access sits at an anemic 56%, has focused extensively on converting flared APG into public power generation. Furthermore, other low energy access countries may follow suit as regulatory policies place increased emphasis on options for APG use in coming years.

---

112 CCSI, Canada APG Utilization Study, July 2014
113 CCSI, North Dakota APG Utilization Study, July 2014
114 CCSI, Nigeria APG Utilization Study, May 2014
115 CCSI, Equatorial Guinea APG Utilization Study, May 2014
116 CCSI, Angola APG Utilization Study, May 2014
117 M. Kanagawa and T. Naka, "Analysis of the Energy Access Improvement Its Socio-Economic Impacts in Rural Areas of Developing Countries," Ecological Economics (2006).

From a technical perspective, using APG in public power generation, either through a public utility or independent power producer, requires compressing the dry gas component of the APG and transporting through high-pressure pipelines. Thus, in all cases it is necessary that operators have access to the pipeline infrastructure to transport the APG to points of distribution. Pipelines projects pose unique challenges for policymakers, largely because they require substantial *ex ante* investments in infrastructure and which once the pipeline completed, risks resulting in the accumulation of monopoly power by the pipeline operator. Given these challenges, the regulator should take care to understand the operational and financial landscape surrounding pipelines projects and ensure that they occur under definite levels of regulatory certainty, fairness, and efficiency.

Pipelines are owned and operated by several types of firms. In countries such as **the United States and Norway**, where state ownership is non-existent and complex regulations exist, long-distance pipelines are typically owned by specialized pipeline companies whose sole function is to operate the pipeline. In some cases, such companies exist as subsidiary of an oil or gas producing company but operate as a separate legal entity.[118] Where pipelines are shorter or where state ownership of energy related companies is prevalent, pipeline operation may be more likely to be handled by the operator (in particular if a state owned company is part of the joint venture operating the field).[119]

The most prevalent commercial structure of pipeline is the tolling model whereby title to the gas never passes to the pipeline but is sold directly by the producer to the local distribution company. In such cases, the pipeline company generates revenue only by servicing the transportation in exchange for a fee.[120] When combined with laws requiring open-access non-discriminatory transportation by pipelines, separation of transportation and merchant functions[121] is a powerful instrument to promote competition in the natural gas sector. Since APG producers often do not produce enough gas to justify construction of dedicated long-distance pipelines, such laws are vital to enable shared use of the pipeline and therefore flaring abatement efforts.

---

[118] J.L. Kennedy, *Oil and Gas Pipeline Fundamentals* (2nd ed. 1993), pp. 10-11.

[119] J.L. Kennedy, *Oil and Gas Pipeline Fundamentals*, op. cit.

[120] NaturalGas.org, "Industry and Market Structure," available at: http://naturalgas.org/business/industry/#industry. Historically, pipeline companies served as both transporters and merchants, directly purchasing the natural gas from the producer, transporting it to market, and then reselling it to a local distribution company.

[121]As a matter of practice, merchant pipelines enter into long-term contracts with producers to guarantee supply.These contracts often contain "take or pay" clauses that require pipelines to take the amount of gas they contract for from the gas producers, or to pay 100% of the price of that gas. Such clauses have been considered desirable during periods of natural gas shortages, ensuring the pipeline a reliable supply and the operator a reliable cash flow to continue operations. When there is a surplus of gas, however, take-or-pay clauses hurt pipelines and their customers, preventing lower-priced gas from penetrating the market. Thus, governments around the world have increasingly required or encouraged pipeline companies to abandon merchant functions in favor of a tolling model.

Box 7: The complexity of a pipeline project

Pipeline development projects are typically complicated, requiring multiple steps including gauging demand and market interest, publicly announcing the project, obtaining regulatory approval, and, finally, construction and testing.[122] An average pipeline project takes about three years from the time it is first announced until the new pipe is placed in service, but this duration can vary depending on whether the project involves building an entirely new pipeline, converting an oil pipeline to a natural gas pipeline, adding a parallel pipeline along an existing segment (called "looping"), installing a lateral or extension off an existing mainline, or upgrading and expanding facilities, such as compressor stations, along an existing route.[123] Depending on the size of the pipeline project, they will frequently be developed by multiple parties, each of which has an interest in either selling or buying the oil or gas. These projects may come in the form of either an unincorporated joint venture or an incorporated joint venture. Use of the unincorporated structure comes with greater uncertainty over how the pipelines and other assets are owned by the developing sponsors as well as the rights and obligations that attach to those ownership interests. For these reasons, the incorporated structure is the more traditional corporate vehicle for pipeline financings.[124]

Downstream activities involve the distribution of generated electricity from generation plants to final consumers across transmission and distribution lines. While this step necessarily involves substantial government regulation and involvement, there is less in the way of potential regulation specific to APG utilization. As a more general matter, governments should ensure that electricity rates paid by final consumers are stable, fair, and adequately compensate the utility or IPP for investments that reduce the long-term cost of electricity and/or increase energy access. In **Nigeria,** the pricing policy of gas supply and power reflects below-market rates, a reality that disincentivizes APG utilization. See Box 8 for a similar experience in **Iraq.**

Box 8: Iraq – Unlocking APG use for power

In Iraq, the fourth largest flarer, a large barrier to utilizing APG is the gas pricing policy stemming from the heavy subsidies for gas usage with industry paying $1.20 per million Btu for the dry gas only.[125] On a case-by-case basis the government enters in individual arrangements with companies to ensure a reasonable price – buying the gas from the companies and reselling to the domestic market.[126] For example, the GGFR-awarded midstream gas company, the Basrah Gas Company (BGC), was created thanks to a price paid by the government for the APG pegged

[122] U.S. Energy Information Administration, "Natural Gas Development and Expansion," available at: https://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/develop.html.
[123] U.S. Energy Information Administration, "Natural Gas Development and Expansion," op. cit.
[124] Norton Rose Fulbright, "Pipeline Financing," available at:
http://www.nortonrosefulbright.com/knowledge/publications/113736/pipeline-financing
[125] L.J. Al-Khateeb, "Natural Gas in the Republic of Iraq," Rice University (Nov. 2013), available at: http://belfercenter.ksg.harvard.edu/files/CES-pub-GeoGasIraq-111813.pdf.
[126] L.J. Al-Khateeb, "Natural Gas in the Republic of Iraq," op. cit.

to the price of oil, somewhere between $3.20 to $4.30 per million Btu for a crude oil price between $75 and $100 per barrel.[127] For the same range of crude oil price, the dry gas is sold at ±US$2.0-2.5 per million Btu in the Middle East.[128] Thus, the Iraq Government covers the difference between the domestic gas price and the negotiated price with BGC and bears the related fiscal burden. BGC is a joint venture with the state owned company, South Gas Company (51%), Shell (44%) and Mitsubishi (5%); it processes APG produced by the three huge oilfields in southern Iraq – Rumaila, Zubair and West Qurna 1, and turns it into dry gas primarily for power generation, LPG for domestic use and condensate for road fuel.[129]

At capacity BGC will buy up to 2 billion standard cubic feet per day of APG from the three oilfields and eliminate routine flaring from these three fields. It is as of today processing more than 600 mmscfd of gas thanks to a massive investment in the rehabilitation of the Iraqi gas infrastructure. To augment this capacity, BGC will also expand the infrastructure but the current low prices have been delaying the plans on the part of both the IOCs and the government. Since March 2016, BGC has managed to cover 70% of the power needs of the Basrah province and 70% of the LPG needs of the country. BGC also exported its first cargoes of condensates and LPG during the second quarter of 2016.[130]

b) Liquefaction

In liquefaction, the "natural gas" of the APG is converted into LNG. LNG consists of high methane components of natural gas that have been cooled to a liquid at a temperature of approximately -260°F and atmospheric pressure.[131] This temperature drop liquefies the methane present in the natural gas, reducing its volume by a factor of more than 600.[132] Liquefaction thereby makes natural gas cost efficient to transport long distances and internationally via cargo ships. LNG has become more economic over the last several decades due to improvements in technology and thermodynamic efficiency, and is now a major gas export method worldwide.[133] Once delivered to its destination, the LNG is "re-gasified," or warmed back into its original gaseous state so that it can be used just like existing natural gas supplies, by sending it through pipelines for distribution to end users.

The construction of an LNG plant typically requires about $1.5 to $2 billion in capital

---

127 L.J. Al-Khateeb, "Natural Gas in the Republic of Iraq," op. cit.

128 CCSI, Iraq APG Utilization Study, Forthcoming 2016

129 Rebuilding Iraq, "Basrah Gas Company Wins the World Bank Global Gas Flaring Reduction Excellence Award," available at: http://www.rebuildingiraq.net/news/view/7901-Basrah-Gas-Company-Wins-the-World-Bank-Global-Gas-Flaring-Reduction-Excellence-Award

130 CCSI, Iraq APG Utilization Study, Forthcoming 2016

131 U.S. Department of Energy, "Liquid Natural Gas," available at: http://energy.gov/fe/science-innovation/oil-gas/liquefied-natural-gas

132 Rigzone, "How Does LNG Work," available at: http://www.rigzone.com/training/insight.asp?i_id=322

133 S. Thomas and R.A. Dawe, "Review of Ways to Transport Natural Gas Energy From Countries Which Do Not Need the Gas for Domestic Use," Energy (Nov. 2003).

investment per train[134] while storage and transport of LNG requires large cryogenic tanks that can typically hold over 100,000 cubic meters of LNG.[135] This reality makes it difficult for LNG producers to use smaller, isolated reserves or serve smaller commercial markets. Thus, small volumes of intermittent APG are not economically attractive for LNG facilities. Nonetheless, where LNG facilities have been constructed, particularly in West Africa, producers have found that such projects not only reduce economic and institutional barriers to APG, but also create opportunities for the development of non-associated gas.[136] In particular, when development projects are backed by the promise of oil revenues, they are, to a certain extent, incremental to the original development investment decision of oil exploitation. In turn, such projects can be supplemented by developments in non-associated gas fields, which benefit from facilities developed for APG use. The LNG projects in Nigeria and Equatorial Guinea are an example of such an economic dynamic.

The LNG value chain is comprised of several components, including LNG liquefaction plants, LNG shipping, and LNG receiving terminals. The first barrier to liquefaction in relation to producers of APG is access to liquefaction plants, The commercial structure used to finance such projects does not conform to a 'global' standard, but varies based on various factors, including governance, applicable legal frameworks, and operational efficiencies (See Box 9).

Box 9: LNG commercial structures

Broadly, there are three major types of LNG commercial structures. First, a project can operate under an integrated structure in which the upstream operator owns the liquefaction plant and sells the produced LNG free on board. Second, the project can operate under a merchant structure in which the liquefaction plant is owned separately from the upstream operator and shares the market value of the produced gas. In both cases, the title to the gas passes to the LNG plant, which is not the case with the third type of commercial structure whereby the liquefaction plant can be operated separately and provide service for a fee without transfer of property.[137] To provide a picture of the complicated contractual issues that may arise in a liquefaction project, the various project agreements that are typical to complete an LNG contract are discussed below.

Shareholders Agreement – Entails the establishment of a separate company by the project sponsors to develop and own the LNG plant facilities. Shareholders in the project company may, depending on the specific needs of the sponsors, include participating gas owners, LNG buyers,

[134] U.S. Department of Energy, "Liquid Natural Gas: Understanding the Basic Facts" (April 2013), pp. 8, available at: http://energy.gov/sites/prod/files/2013/04/f0/LNG_primerupd.pdf

[135] International Human Resources Development Corporation, "LNG Value Chain," available at: https://www.ihrdc.com/els/po-demo/module15/mod_015_02.htm

[136] CCSI, Equatorial Guinea APG Utilization Study, May 2014

[137] S.R. Miles, "Legal Structures and Commercial Issues for LNG Export Project – North America & Beyond," Baker Botts LLP (Jan. 2013), pp. 7.

the Government, and other third parties.[138]

Gas Sales Agreement – In a merchant structure, this agreement binds the upstream owners to sell gas to the project company established in the shareholder agreement. The gas sales agreement typically specifies the quality of the natural gas that will be produced and allocates shortfall liability to either the upstream operator of the project company.[139]

Liquefaction Agreement – In a tolling structure, this agreement obliges the project company to render the liquefaction service at the request of the operator up to the contracted volumes. While gas sales agreements generally are tied to take-or-pay agreements, tolling plants are less willing to cover damages in their contracts. Since tolling fees are not usually indexed to the price of LNG, project companies risk facing liabilities that far exceed anticipated commercial margins.[140]

Shared Facilities Agreement – Depending on the ownership interests involved, this agreement establishes governance arrangements for defined facilities that are shared across the project to ensure all project participants have reasonable access to facilities required to enable liquefaction and delivery.[141] The shared facilities will vary from project to project.

Sale and Purchase Agreement or Sell or Pay Agreement (SPA) – given the high capital expenditure involved in a LNG project and given the regional fragmentation of the spot market, the development of an LNG project will generally not start without a long term off take agreement between gas producers and buyers. For example, Punta Europa, an ongoing LNG project in **Equatorial Guinea,** took off under a 17 year SPA with BG group for 3.4 MTPA of LNG.[142] Similarly, **Nigeria** LNG currently manages 16 SPA contracts and produces 22 MTPA as of 2011.[143]

For the reasons stated above, potential participants in a liquefaction project must negotiate project agreements with diligence and caution. Successful liquefaction projects in developing countries have typically involved joint arrangements between upstream blocks or public-private partnerships. Such arrangements minimize the liability risk and financial commitment of individual project participants while also leveraging a more diverse legal and technical expertise. As stated previously, however, in such cases it is necessary for all project participants, particularly government sponsors, to remain credible investors for the life of the project, or there is a disenabling risk that the project will be delayed or aborted.

---

[138] S.R. Miles, "Legal Structures and Commercial Issues for LNG Export Project – North America & Beyond," op. cit., pp. 5.
[139] S.R. Miles, "Legal Structures and Commercial Issues for LNG Export Project – North America & Beyond," op. cit., pp. 5.
[140] J.L. Valuera, "LNG Contracts Require Diligence, Caution," 239 Pipeline & Gas Journal 11 (nov. 2012), available at: http://pgjonline.com/2012/11/26/lng-contracts-require-require-diligence-caution/
[141] Law360, "Shared Common Facilities in LNG Project" (April 17, 2015), available at: http://www.law360.com/articles/643065/shared-common-facilities-in-lng-projects.
[142] CCSI, Equatorial Guinea APG Utilization Study, May 2014
[143] CCSI, Nigeria APG Utilization Study, May 2014

It should also be noted that some of same issues related to investor credibility and shared use that apply in high-pressure pipelines contexts also apply to the development of LNG facilities, and as such may justify active state involvement. In **Angola,** where the Soyo LNG project is seen as one of the most successful APG-based infrastructural developments in recent decades, upstream blocks to the project agreement were required to pay all capital costs for developing the gathering infrastructure necessary to transport APG to the new facility. Furthermore, these companies were allowed to include the costs in their PSA cost recovery, shared operating costs after completion of the project, and also jointly participate in management of the facility. That said, full title to the facility and gathering infrastructure was transferred to the NOC, Sonangol, on completion, a step seen as necessary to enable new fields to access the LNG plant in the future.

In a similar process to LNG, the dry gas components of APG can also be transported as compressed natural gas ("CNG") through ship or vehicular transport. Although commonly confused with LNG, the distinction is that CNG is stored as a gas at high pressure – generally at around 3,600 psi[144] – whereas LNG is stored as a liquid at low temperature. The primary advantage of CNG relative to LNG is generally thought to be its faster deployment, much lower capital investment costs, and lower environmental impact. CNG projects do not require massively expensive liquefaction and regasification plants, making the overall supply chain an order of magnitude less expensive than LNG. Furthermore, since CNG does not experience "boil off,"[145] gas emissions from ships and storage facilities, they are thought to have a more modest greenhouse footprint.[146] Still, since CNG exists in gaseous forms, storage is necessarily more expensive. CNG as an APG utilization option is thus most suitable for small-to-medium regional markets, while LNG is better geared for large scale, long haul projects.[147]

A final related process is known as "gas-to-liquids," which involves converting APG into liquid fuels such as gasoline, jet fuel, and diesel.[148] The most common technique to achieve this objective is Fischer-Tropsch synthesis, which has gained recent interest because of the growing spread between the value of petroleum and the cost of producing natural gas, and involves converting the methane into a mixture of hydrogen, carbon dioxide and carbon monoxide known as syngas.[149] The syngas is then cleaned to remove sulfur, water, and carbon dioxide. Prior to 2016, there were five GTL plants operating globally, as well as one in Nigeria that is under construction. Thus, less in the way of policy can be deduced from the GTL experience thus far than perhaps is desirable, though as a general matter it is most viable when gas volume is large, domestic demand for liquid fuels is strong, and large financing is available.

---

144 Agility Fuel Systems, "Natural Gas Fuels: CNG & LNG," available at: http://www.agilityfuelsystems.com/lng-vs-cng.html.

145 LNG must be kept cold to remain a liquid, making heat leakage inevitable. Boil-off gas acts to keep the LNG cold.

146 EnerSea Transport LLC, "Understanding CNG," available at: http://enersea.com/understanding-cng/.

147 EnerSea Transport LLC, "Understanding CNG," op. cit.

148 U.S. Energy Information Administration, "Gas-to-liquids plants face challenges in the U.S. market" (Feb. 19, 2014), available at: http://www.eia.gov/todayinenergy/detail.cfm?id=15071

149 U.S. Energy Information Administration, "Gas-to-liquids plants face challenges in the U.S. market," op. cit.

Nonetheless, it is plausible that gas-to-liquids technology will take on a more prominent role in flaring abatement efforts in the years that follow. In 2016, Greyrock Equity Partners, LLC, an American company that specializes in converting natural gas, partnered with Compañia Petrolera Perseus, a leading Mexican energy company, in a joint venture to convert otherwise flared natural gas in Mexico into liquid fuels including clean, premium diesel.[150] According to its website, Greyrock's "flare to fuels" systems "are modular, easily transportable and remotely controlled for the production of 5 to 10 barrels per day of clean fuels from flare gas."[151] Furthermore, although the systems are designed to operate on a small-scale, multiple "systems can be deployed as needed to process larger flare gas volumes."

The systems that Greyrock intends to build are to be located at the well pad. The fuels produced can either be blended with the oil at the well pad or processed further. The diesel that is produced "features high cetane, no sulfur, and good lubricity." According to Greyrock, these fuels do not require further refining and upgrading as opposed to those coming from Fischer-Tropsh based technologies. In this way, Greyrock argues that its system reduces "the complexity and costs associated with traditional natural gas-to-liquids processes by bypassing the intermediate hydrocarbon wax that normally needs to be refined into finished products."[152]

Whether the Greyrock-Perseus joint venture will be successful in converting substantial flaring to gas utilization is still unclear, however, though there multiple deployments scheduled for 2017. Greyrock has not disclosed financial terms of the deal, but from past experience the typical cost of a single Greyrock deployment should fall somewhere in the (admittedly quite broad) range of $10 million to $250 million.[153] Some reasons for optimism include the World Bank's recognition through its Global Gas Flare Reduction Partnership of Greyrock technology as the "top solution for the elimination of flare gas worldwide,"[154] Greyrock's successful solicitation of large investments by major natural resources players,[155] and its successful deployments in other natural gas contexts, particularly in the United States.[156] Whether modular-based gas plants will be able to achieve the same scale of flaring reduction as has been seen in large LNG plants remains to be seen, however, and will depend on the companies' abilities to effectively identify reservoir candidates suitable for gas-to-liquids conversion.

---

[150] PR Newswire, "Perseus and Greyrock announce Joint Venture to Monetize Flare Gas in Mexico," May 31, 2016

[151] Greyrock, http://www.greyrock.com.

[152] Greyrock, op. cit.

[153] Sacramento Business Journal, "Sacramento Energy Technology Company Greyrock Pursues Mexican Clients with Partnership," May 31, 2016.

[154] Oil & Gas News, "Greyrock Direct Fuel Production(TM) recognized by World Bank as most advanced technology for Gas-to-Liquids," Aug. 29, 2016, http://www.youroilandgasnews.com/greyrock+direct+fuel+production(tm)+recognized+by+the+world+bank+as+most+advanced+technology+for+gas-to-liquids_136333.html

[155] Oil & Gas News, "Anglo American Platinum Invests in Greyrock Energy," Sep. 19, 2016, http://www.youroilandgasnews.com/anglo+american+platinum+invests+in+greyrock+energy_136836.html.

[156] Gas Processing News, "Greyrock Energy Grants Final Approval on Houston Small-Scale GTL Plant," http://gasprocessingnews.com/news/greyrock-energy-grants-final-approval-on-houston-small-scale-gtl-plant.aspx

Key Takeaways from Recommendation Four

- Under a strongly enforced no-flare policy, operators may choose to utilize APG on-site through reinjection or to provide power to on-site facilities, which will both limit flaring and contribute to the bottom-line of the company. However, experience with using on-site utilization technologies indicates that they do not constitute a fully comprehensive solution to flaring at most fields.
- Depending on the quantity of APG, the country's level of infrastructural development and demand for energy, a strongly enforced no-flare policy that also deploys the right compensation framework will encourage operators to monetize APG either to satisfy the domestic demand in power, fuel and feedstock for petrochemical industries or for exports. This compensation framework is needed because such strategies require substantial *ex ante* capital investment in high-compression pipelines or liquefaction facilities.
- The best solution for APG use will be country-specific and conceiving this solution will require a sharp understanding of the issues at stake; an expert panel composed of representatives of the industry, flaring experts and regulators could be in charge of development this understanding and informing policy-makers.

Conclusion

Although APG utilization is economically viable and socially necessary as a solution to harmful flaring operations, oil companies are unlikely to commit financial resources to utilization projects in the absence of regulatory institutions that adequately incentivize the conversion of the necessary facilities, foster an investor-enabling environment for the construction of new infrastructure, and facilitate operators in overcoming a varied set of financial and technical constraints. Here, we have provided a basic overview of the APG value chain, outlined the barriers that stand in the way of effective utilization, and analyzed a multitude of strategies that we have found through our case studies.

The policy solution at which we arrive centers around the decoupling of regulatory authority for production operations, a stringent penalty approach to combat the microeconomic incentives powering flaring activities, and a multi-faceted utilization strategy that requires a broad-based understanding of available tactics at each point in the value chain. Although there has been considerable progress on the part of many host countries to achieve this basic model, there remain lingering institutional issues and regulatory uncertainties that stand in the way of total conversion of flaring operations to APG utilization. Nonetheless, the successful implementation of a clear, transparent, and sound policy regime has the potential to produce rapid APG-driven growth across world economies, hopefully reducing the need to burn more reserves, which would enable the world to respect the Paris Agreement.

III. Annexes

Annex 1: Using gas for on-site generation – Prevalent approaches

- ***Fuel cells*** – Fuel cells generate electricity through an electrochemical reaction, known as reverse electrolysis, in which hydrogen and oxygen combined to form water vapor, heat and electricity. Theoretically, any fossil fuel can produce the hydrogen necessary for a fuel cell, but natural gas is generally considered the most cost-effective. Fuel cells can operate as high as 90% efficiency if full heat recovery is included.[157] A recent study found that a natural gas fuel cell system would produce 15 percent less carbon dioxide per kW than a modern natural gas combined cycle power plant.[158] Still, fuel cells are costly to produce, only store a relatively small amount of power, are highly flammable, and wear down quickly.[159]

- ***Gas-fired reciprocating engines*** – These engines convert the energy contained in natural gas into mechanical energy, which rotates a piston to generate electricity.[160] Reciprocating engines offer efficiencies from 25 percent to 45 percent and are also more suitable for small-scale generation, producing approximately 5-7 MW of power.

- ***Industrial gas-fired turbines*** – Operating in much the same manner as centralized gas turbines, this equipment produces electricity by using hot gases from burning natural gas to turn a turbine that generates a current.[161] Industrial turbines are relatively simple to operate and can achieve an efficiency up to 58 percent. ***Microturbines*** are scaled

[157] GP Renewables & Trading, "Clean Distributed Power Generation at Natural Gas Wellheads," available at: http://www.gprenew.com/files/documents/GP%20Clean%20Distributed%20Power%20for%20Natural%20Gas%20Drilling%20Brochure.pdf

[158] L. Chick, M. Weimer, G. Whyatt and M. Powell, "The Case for Natural Gase Fueled Solid Oxide Fuel Cell Power Systems for Distributed Generation," *Fuel Cells* (2015), pp. 49-60.

[159] Naveena Sadasivam, "Hydrogen Fuel Set to Take Off, But Safety Concerns Remain," *ProPublica* (Feb. 18, 2014), available at: https://www.propublica.org/article/a-new-road-rage

[160] NaturalGas.org, "Electrical Uses," available at: http://naturalgas.org/overview/uses-electrical/

[161] NaturalGas.org, "Electrical Uses," op. cit.

down versions of industrial turbines that are able to produce from 25 to 500 kW of power.[162]

Annex 2: Representative molecule (MOL) compositions of various produced petroleum after separation at the surface

		MOL Percent			
Component	Symbol	Crude Oil	Associated Gas	Wet Gas	Dry Gas
Methane	C_1	37.54	67.32	59.52	97.17
Ethane	C_2	9.67	17.66	5.36	1.89
Propane	C_3	6.95	8.95	4.71	0.29
i-Butane	i-C_4	1.44	1.29	2.03	0.13
n-Butane	n-C_4	3.93	2.91	2.39	0.12
i-Pentane	i-C_5	1.44	0.53	1.80	0.07
n-Pentane	n-C_5	1.41	0.41	1.61	0.05
Hexane	C_6	4.33	0.44	2.60	0.04
Heptanes Plus	C_7+	33.29	0.49	19.98	0.24
		100.00	100.00	100.00	100.00

Source: IRDC, op.cit.

[162] NaturalGas.org, "Electrical Uses," op. cit.