Overview
Associated Petroleum Gas (APG)

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Thanks to Tom Mitro and Tom Wairegi for their thoughtful review
Outline of Presentation

- Definition of APG and gas flaring
- Impacts of gas flaring
- Barriers to effective APG utilization
- APG utilization options overview
- Potential fiscal and institutional frameworks for APG use
Associated Petroleum Gas (APG), also known as flare gas or associated gas, is natural gas that is dissolved in oil from the reservoir. It is a by-product in oil extraction.

APG is also found in condensate or “wet gas” fields when the operator is interested in liquids (with the APG being dry gas that is not collected).

APG is composed mainly of light hydrocarbons such as methane (up to 81%) and heavier components including ethane ($C_2H_6$), propane ($C_3H_8$), butane ($C_4H_{10}$) and others.

APG is vented or flared (intentional burning) when it is not used on other applications. Flaring is preferable to venting because the latter can release larger quantities of methane and volatile organic compounds into the atmosphere. However, both venting and flaring are harmful to the environment.
The negative impacts of APG flaring

- The negative environmental effects of gas flaring are well documented with the World Bank’s Global Gas Flaring Reduction Partnership (GGFR) stating that flaring produces about 400 million tons of greenhouse gas emissions globally each year.

- The negative health effects of exposure to hazardous air pollutants released during incomplete combustion of gas flaring have also been well studied.

- Flaring can also be assessed in terms of foregone revenues which were as high as $2.5 billion per year in Nigeria alone between 1970-2006.

Methane is a much more intensive greenhouse gas than carbon dioxide
<table>
<thead>
<tr>
<th>Economic (cost issues) barriers</th>
<th>Institutional and regulatory barriers</th>
<th>Geology</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Distance from major gas markets</td>
<td>• Limited institutional, legal and regulatory framework for gas flaring and use</td>
<td>If barriers are lifted, the quantity, quality and pressure of the gas in the reservoir will determine the best use (between reinjection and gas processing method)</td>
</tr>
<tr>
<td>• Underdeveloped domestic market for dry gas/products (NGL, LPG, CNG, methanol, power, etc.)</td>
<td>• Ineffective fiscal terms (gas price, equity share, tax structure, etc.)</td>
<td></td>
</tr>
<tr>
<td>• Reliability of supply</td>
<td>• Funding constraints and the need for coordinated actions by several stakeholders</td>
<td></td>
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<tr>
<td>• Gas infrastructure constraints</td>
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Despite knowledge of the negative environmental, economic and health impacts of gas flaring, there remain economic and institutional barriers to APG utilization.
Unlocking economic and institutional barriers opens a wealth of opportunity not only for APG but also for Non-Associated Gas (NAG).

The case of the West Africa Region has demonstrated that APG use via capital intensive projects such as LNG plants is possible because it is backed by oil revenues. Such projects, to a certain extent, are incremental to the original development investment decision of oil exploitation.

In turn, those projects using APG can be supplemented by developments in NAG fields which benefit from facilities developed for APG use.

Simply put, in these regions, APG makes NAG exploitation cheaper.
As depicted above, there are four options commonly used in monetizing APG: reinjection, power generation, compression and liquefaction.

Those options depend on the quantity of APG, the pressure and the quality of APG, the relative market price of oil versus gas, the tariff being charged by the gas owner, the purchasing price of the gas and the distance to the processing plant or consumers (see next slide).

The existence of a wide and integrated network of pipelines around the scattered oil and gas fields will accelerate the use of APG. Pipelines can be costly when the volume of the gas is small, the customers are far and the pipeline is used for a single source and destination.
### Economics of key APG use options

#### Main factors determining the economic attractiveness of key gas use options are broadly related to APG supply, geographical factors like distance to gas infrastructure and market related factors like the local electricity price.

#### An overview of APG utilization options

#### Comparing APG utilization options

#### Fiscal and institutional frameworks

#### Source: Carbon Limits Report
APG utilization options: Reinjection

Option | Advantages | Disadvantages
--- | --- | ---
Re-inject for future use | Reservoir preservation | Not all formations are suited for reinjection because of high capital cost for local processing and compression
Re-inject for Enhanced Oil/Gas Recovery (EOR/EGR) | Provides revenue through increased oil production, may allow future recovery of re-injected gas | Not all formations are suitable for gas EOR/EGR because of high capital cost for local processing and compression

- With no regulation, it might still be cheaper to flare.
- When reducing flaring is the objective, projects to re-inject associated gas can create attractive returns and utilize some, but not all, of the associated gas production. To completely eliminate flaring, investments must also be made in projects to export the associated gas or sell to local markets. But due to the downstream disruption risks to upstream oil production, export projects rarely can rely on associated gas as their primary source of feedstock.
- For old and heavy oil fields, reinjection is not effective nor economic. Gas-lift is then more appropriate but uses less APG. Gas-lift, as opposed to reinjection, injects gas into “the annulus” of the the well and not in the reservoir. The annulus is the void between any piping, drill string and the formation being piped, drilled.
## APG utilization options: Gas reinjection types

<table>
<thead>
<tr>
<th>Gas types used in reinjection</th>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural gas (dry, mostly methane)</td>
<td>No harmful effects on the field</td>
<td>Too expensive for reinjection, used only when no economical way to recover for sales to the market</td>
</tr>
<tr>
<td>Associated Petroleum Gas (methane + saturated hydrocarbons: ethane, propane, butane + some CO2 and N2)</td>
<td>Readily available after separation from oil</td>
<td>Sometimes not enough of it produced to cover reinjection needs. Gas sales might be more profitable than reinjection</td>
</tr>
<tr>
<td>Carbon dioxide (CO2)</td>
<td>Used in the US because of tax subsidies and significant natural reserves</td>
<td>Only means of producing it is to remove it from turbine exhaust or flue gas sources; a very expensive, complicated procedure</td>
</tr>
<tr>
<td>Flue gas (exhaust from gas turbines, power plants, etc.) – (made of 88% N2, 12% CO2)</td>
<td>Cheaper than hydrocarbon gas, especially if can be easily extracted from sources of combustion like power plants and gas turbines</td>
<td>Can be very corrosive to production equipment</td>
</tr>
<tr>
<td>Nitrogen (N2)</td>
<td>Noncorrosive, doesn’t contribute to greenhouse effect, lowest volume requirement for pressure maintenance</td>
<td>Can contaminate natural gas and be expensive to remove</td>
</tr>
</tbody>
</table>

Source: Adapted from Vincent, OGJ 2001

*APG, along with Nitrogen, is often a dominant strategy among reinjection options for producers.*
### APG utilization options: Power generation

<table>
<thead>
<tr>
<th>Option</th>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Local electricity generation</strong>: using on-site power generators</td>
<td>Savings in purchased electricity or purchased diesel for power generation (lower opex for oil producers)</td>
<td>Capital cost; field typically requires only 30% of the power that APG could generate. Other local markets may be limited or nonexistent.</td>
</tr>
<tr>
<td><strong>Regional electricity generation</strong></td>
<td>Economic and environmental savings in purchased diesel to generate power – engine of regional integration</td>
<td>Capital cost of gathering and processing infrastructure; low domestic electricity prices limit price offered for gas</td>
</tr>
</tbody>
</table>

🔍 When gas prices are low and volume of gas is small, local generation will be more economic than regional electricity generation.
APG utilization options: Liquefaction

- Liquefaction = Processing APG into:
  - Liquefied Natural Gas (LNG),
  - Liquefied Petroleum Gas (LPG)
  - Gas-to-Liquids (GTL)

- In the case of condensate/wet gas, the dry gas is considered to be APG when only Natural Gas Liquids (NGL) are extracted.
### Definitions: LNG, LPG, GTL, NGL

<table>
<thead>
<tr>
<th>NGL</th>
<th>LPG</th>
<th>LNG</th>
<th>GTL</th>
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</thead>
<tbody>
<tr>
<td>Consists primarily of molecules heavier than methane (CH4) like ethane, propane and butane separated from gas as liquids through methods such as absorption, condensation in gas processing or cycling plants; exists as condensate at low pressure, LPG at high pressure, and natural gas at intermediate pressure</td>
<td>A mixture of primarily propane (C3) and butane (C4) that exists in a liquid state at room temperature</td>
<td>Natural gas that has been cooled to a liquid at a temperature of approximately -256 °F and atmospheric pressure; consists primarily of methane</td>
<td>Process of converting natural gas to liquid products like methanol, middle distillates (diesel and jet fuel), diethly ether (DME), specialty chemicals and waxes</td>
</tr>
</tbody>
</table>
Different chemical compositions among the liquefaction options

An overview of APG utilization options

Comparing APG utilization options

Fiscal and institutional frameworks

CNG is included for comparison purposes but is not a form of liquid gas (see slide before)

Source: University of Houston Institute for Energy, Law & Enterprise
The LNG industry is composed of several chains including LNG liquefaction plants, LNG shipping, LNG Receiving Terminals. LNG is very capital intensive but is justifiable if there is huge gas volume, demand is strong, distance to consumer is far (~5000km) and strong LNG sales purchase agreement (SPA) between gas producers and buyers exist.

CNG (Compressed Natural Gas) is often confused with LNG. CNG is stored as a gas at high pressure whereas LNG is stored as liquid at very low temperature. CNG’s cost of production is therefore lower than that of LNG, while requiring higher storage capacity. Thus, LNG is used for transporting gas over long distance and is re-gasified (CNG) for distribution.
For use at the local level, as compared to LNG, LPG presents the advantage of not necessitating a large demand and can serve small scale use in cooking, fertilizer plants and power generation. Its production cost is lower than LNG and is easy to use and transport. Its components (C3 and C4) are in small quantity in APG however, so the use of gas is rarely on dedicated for LPG; the LPG plant is usually developed in combination with other gas use options, such as pipeline development to deliver methane (CH4) or as a part of LNG development. The combination then enhances the project attractiveness.
The GTL technology is often called Fischer-Tropsch-Gas-to-Liquids (FT-GTL) technology because the Fischer-Tropsch chemical conversion is a process of converting gas into liquid hydrocarbons. GTL will only be competitive when 1) the gas volume is large, 2) demand for GTL is very strong, 3) the technology can be provided and 4) large financing is available.
Fiscal Stimuli - Incentives and Penalties are two types of fiscal stimuli typically used by host governments to promote investment in gas flaring and venting reduction projects. They can be introduced into production licenses or production sharing agreements as well as in fiscal laws.

- **Penalties** are imposed uniquely on flaring and venting of APG that occur during upstream operations. They stimulate the effective utilization of APG by making flaring economically infeasible.

- **Incentives** are required for stimulating investment in utilization of APG, particularly in conditions of underdeveloped domestic gas markets and limited export opportunities.
### Examples of fiscal incentives

The most common financial incentives used for APG projects are:

1. **lower royalty rates** (e.g. Nigeria, Tunisia, Vietnam);
2. **higher cost-recovery ceilings and/or profit shares** (e.g. Egypt, Indonesia, Malaysia);
3. **lower tax rates** (e.g. Nigeria, Tunisia, Papua New Guinea);
4. **reduction of existing oil taxes** (e.g. Trinidad and Tobago (Supplementary Petroleum Tax))
5. **Qualifying APG project as Clean Development Mechanisms (CDM)** enabling the company to gain carbon credits under a cap and trade system established in certain countries/regions upon ratification of Kyoto’s protocols.

### Framework for Penalties

Penalties usually take the form of a fine imposed on gas flared or vented. There are 3 important conditions for penalizing policy to address flaring and venting effectively:

1. **High Level**: The level of penalty should be high enough to make the options of effective utilization more attractive than paying.
   - **Carbon tax** - sets a price for a unit of emission – easy to administer and flexible for the polluter (investing in flaring reduction to the point where the cost of reducing one more unit of emissions is just equal to the tax per unit of emissions)
2. **Established regulatory framework**: The presence of a strong, independent regulatory body is necessary to measure and report requirements, monitor flare and vent volumes, enforce the regulations and pursue the penalties.
3. **Combination of approaches**: The combination of the penalty approach with other fiscal incentives has proved to be the most effective fiscal policy.
Challenges of taxation of LPG

- Liquids can be sold on the same price terms as oil. On this basis, policy makers often impose the same fiscal terms as oil. However, it generates disincentive for broader gas developments.

- High liquids content in a natural gas project significantly enhances its profitability and can enable producers to charge a lower price for gas. This can make the difference between a gas project being economically viable or not. When the liquids are liable to a high tax rate (e.g. oil tax rates), this economic benefit can be minimized for investors. Therefore, it is important to consider how condensate is treated under differentiated fiscal terms, as this can influence the pace of development of the gas industry.

- In the case of NGL and LPG produced from APG, the facilities used for liquids separation and export are the same as those established for the production and export of oil. As a result it is more difficult for investors to argue for better fiscal terms for the liquids and differentiated profits are more difficult to establish. Applying the same fiscal terms for both oil and LPG represents an issue when LPG prices fall below oil prices.
Institutional reform to encourage APG utilization

An overview of APG utilization options

• Clear guidelines and rules on gas utilization targets
• Effective fines and other penalties
• Regulatory clarity
• Support for state-private partnerships’ investments into APG projects, with main focus on the regions with a high flaring
• Subsidies for APG

Comparing APG utilization options

• Clear roles and objectives
• Autonomy
• Participation
• Accountability
• Transparency
• Predictability

Fiscal and institutional frameworks

• Enforcement based on step-wise penalties, including license revocation;
• Consistent and non-discriminatory enforcement.

Market mechanisms that create means and incentives for commercialization of PG (liberalized prices, regulated third-party network access, etc.)

Source: PFC, World Bank
### Annex: Energy conversion table

<table>
<thead>
<tr>
<th>From</th>
<th>To</th>
<th>Billion cubic meters gas bcm</th>
<th>Billion cubic feet gas Bcf</th>
<th>Million barrels oil equivalent mmboe</th>
<th>Million tonnes oil equivalent mmtoe</th>
<th>Trillion / million tonnes LNG</th>
<th>British Thermal units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Billion cubic meters gas bcm</td>
<td>1</td>
<td>35.31</td>
<td>6.10</td>
<td>0.83</td>
<td>0.7</td>
<td>36.7</td>
<td></td>
</tr>
<tr>
<td>Billion cubic feet gas bcf</td>
<td>0.028</td>
<td>1</td>
<td>0.17</td>
<td>0.024</td>
<td>0.020</td>
<td>1.04</td>
<td></td>
</tr>
<tr>
<td>Million barrels oil equivalent mmboe</td>
<td>0.16</td>
<td>5.79 (one can use conversion factor of 6)</td>
<td>1</td>
<td>0.14</td>
<td>0.116</td>
<td>6.02</td>
<td></td>
</tr>
<tr>
<td>Million tonnes oil equivalent mmtoe</td>
<td>1.20</td>
<td>42.55</td>
<td>7.35</td>
<td>1</td>
<td>0.86</td>
<td>44.21</td>
<td></td>
</tr>
<tr>
<td>Million tonnes LNG</td>
<td>1.41</td>
<td>49.74</td>
<td>8.59</td>
<td>1.17</td>
<td>1</td>
<td>51.69</td>
<td></td>
</tr>
<tr>
<td>Trillion British Thermal units (tbtu)</td>
<td>0.027</td>
<td>0.96</td>
<td>0.17</td>
<td>0.023</td>
<td>0.019</td>
<td>1</td>
<td></td>
</tr>
</tbody>
</table>

1 tbtu = 1 bcf
1 mscfd = 0.01 bcm
1 therm = 100,000 btu
1 therm = 0.1 mmbtu
1 CF = 0.01 mmbtu

1000 cubic meters to mmbtu = divide 1000 by 35.315 to get price in mmbtu

trillion = one thousand billion

If one had the price of natural gas in therm and one wants to convert it to the price per mmbtu, one needs to multiply by then (50 cents per therm = 55 mmbtu)

Source: Energy dictionary
References


References


- "What is associated Petroleum Gas." Gazprom, Web. 04 May 2014