Appendix: Case studies

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ENI CONGO: GAS-TO-POWER PROJECT

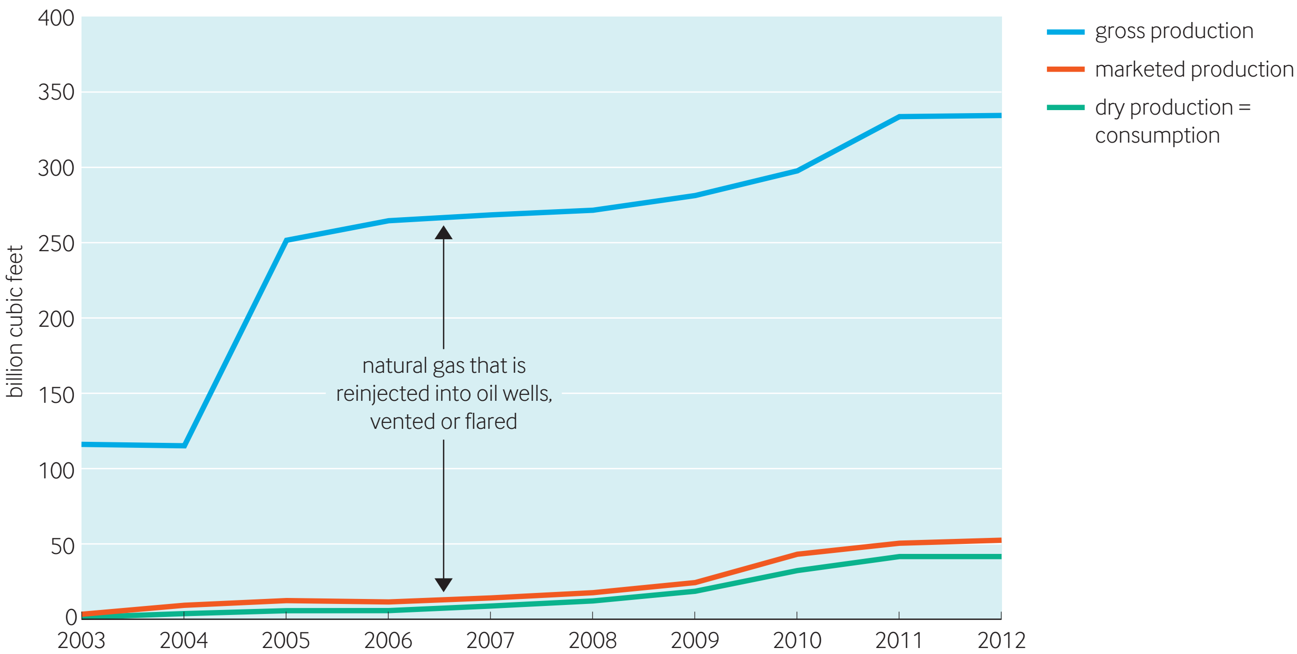
In 2007 Eni signed an agreement with the government in the Republic of Congo to develop two electricity power stations in order to eliminate gas flaring. The agreement included the construction of the new Centrale Electrique du Congo (CEC) power station and the revamping of the existing Centrale Electrique de Djéno (CED) power station. By utilizing more than 70 million scf/day of gas (1.98 million cubic meters per day) that was previously flared, the power stations provide 60% of the country's installed capacity and expand access to electricity for approximately 700,000 people.

Background

Historically, the vast majority of gross gas production in the Republic of Congo was not monetized, as shown in Figure A1.

While flaring and venting of gas decreased by around 30% from its peak of 2.2 bcm in 2005 to 1.56 bcm in 2012,[18] this trend was reversed in 2017, as shown in Figure A2 on page 101.

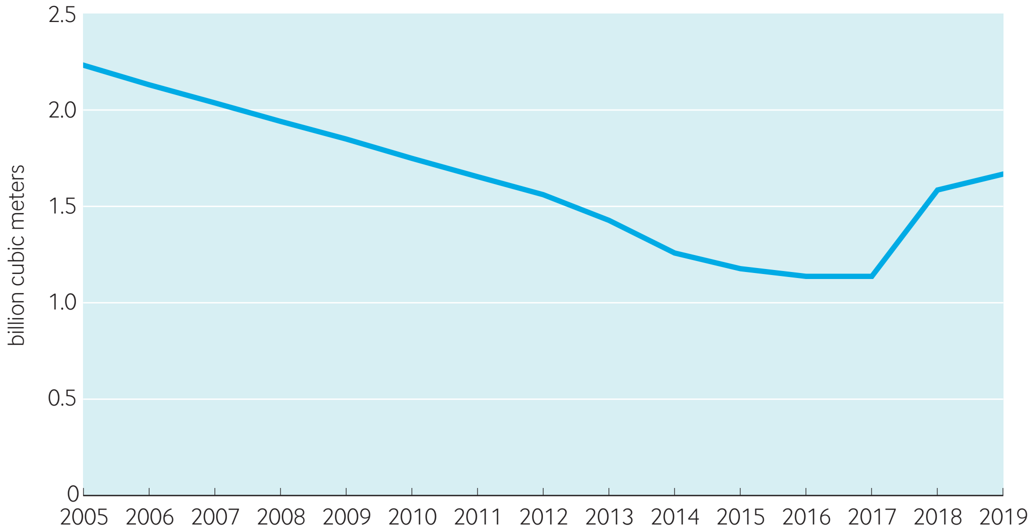
Figure A1 Natural gas production and consumption in the Republic of Congo, 2003–2012[19]



[18] Equivalent to 79 bcf in 2005, and 55 bcf in 2012.

[19] https://www.eia.gov/international/analysis/country/COG

Figure A2 Gas flaring in the Republic of Congo, 2005–2019[20]



The oil and gas industry is overseen by the Ministry of Hydrocarbons with resources managed by the state-owned company, Société Nationale des Pétroles du Congo (SNPC). A new hydrocarbons code enacted in 2016 represents the Ministry of Hydrocarbons' strategy for the country. It encourages exploration and production activities by introducing provisions conducive to the recovery of investment by private companies, as well as more favorable fiscal and customs regimes. Certain taxes and fees are imposed for gas flaring. With respect to associated gas utilization, an earlier code, Decree 2007/294, prohibits systematic flaring by operating companies. Any flaring must be reported to the government. The Republic of Congo recently endorsed the 'Zero Routine Flaring by 2030' initiative.

In 2019, Congo held 284 bcm of proven natural gas reserves, and the market production was 0.58 bcm.[21] All of the marketed production was consumed domestically. A significant portion of the natural gas produced in Congo is reinjected into oil wells to assist recovery.

Société Nationale d'Electricité (SNE), the national electricity company, controls the electricity generation, transmission and distribution sectors. Power consumption is low in Congo because of the limited transmission system that mainly serves the country's principal cities, Brazzaville and Point-Noire. In urban areas, the demand for electricity has increased over the past decade, and Congo has had to rely on power imports to satisfy domestic consumption. Hydropower accounts for a substantial portion of the country's power generation.

Honoring its public commitment to eliminate flaring, maintaining compliance with all applicable regulations and working as a trusted partner with resource owners are key drivers for Eni's comprehensive approach to implementing flaring reduction projects. As an endorser of the 'Zero Routine Flaring by 2030' initiative, the company has established an internal policy and process to identify flare reduction and gas monetization/utilization projects.

[20] Sources include:

- http://pubdocs.worldbank.org/en/503141595343850009/WB-GGFR-Report-July2020.pdf
- https://www.worldbank.org/en/programs/gasflaringreduction/global-flaring-data
- https://www.researchgate.net/publication/265335324
- https://www.eia.gov/international/analysis/country/COG

[21] https://www.opec.org/opec_web/en/about_us/5090.htm

Operational enhancements in the company's program to reduce associated gas flaring include: adding compression to move the gas to market; in-field generation of electricity using associated gas; direct measurement of the volumes of gas flared; managing process/equipment start-ups to reduce flaring; and enhancing the maintenance of equipment to improve reliability.

Project description

Following the acquisition of the existing M'Boundi onshore oilfield in 2007, Eni developed a large-scale energy access model in the country. In the same year the company launched an integrated project with the dual purpose of increasing electricity capacity and reducing gas flaring. In 2008, Eni began constructing two gas-fired power plants (CEC and CED), upgrading the energy transport infrastructure between Pointe-Noire and Brazzaville, and extending the electricity distribution network in the city of Pointe-Noire. In the first phase of this project, a 300 MW electricity production plant was built which started operating in March 2010. It supplies the town of Point Noire which has a population of approximately 700,000 people. At the end of 2011, the high voltage electricity line between Punta Nera and Brazzaville was put into operation. The project was designed to promote the country's energy resources, maximize the use of gas for electricity production, improve the energy distribution system in the area and enhance the development of local markets.

Prior to the project, the M'Boundi oilfield produced approximately 1.98 million cubic meters of associated gas per day, all of which was flared. The API gravity of oil produced (some by hydraulic fracturing) in the field is 34–49 and has a GOR of 86 cubic meters/bbl. The gas is approximately 75% methane and contains less than 3% pentanes plus higher carbon hydrocarbons (C_5+) and less than 0.5% CO_2, nitrogen and H_2S.

The integrated M'Boundi gas valorization project, with a total cost of approximately USD 300 million, included the implementation of the following sub-projects aimed at recovering and utilizing the associated gas that was previously flared at the M'Boundi oilfield:

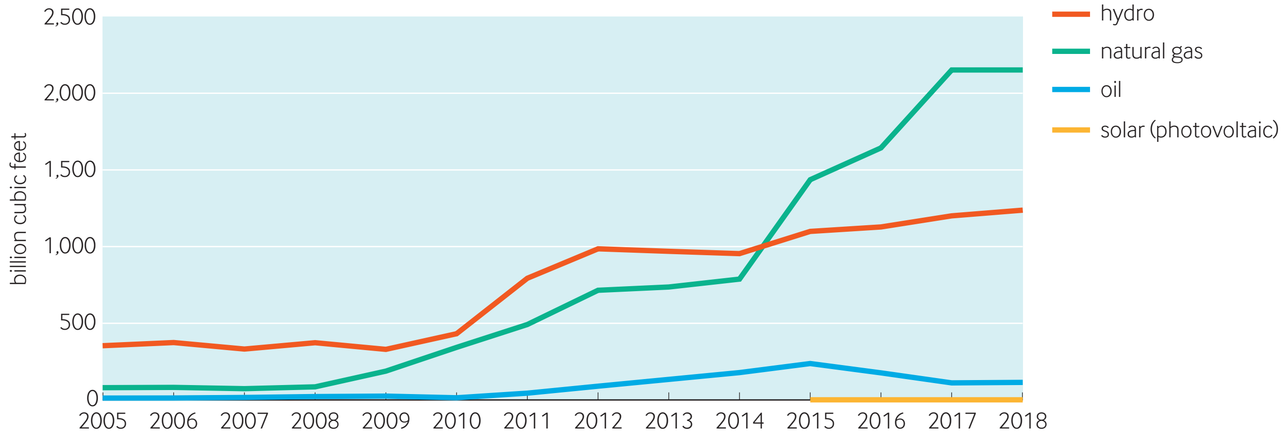
- **M'Boundi gas gathering:** a pipeline was constructed to transport recovered gas from M'Boundi to the Djéno area, where the power plants are located. Eni installed the necessary gas capture, treatment, compression and pipeline infrastructure, along with facilities for condensate recovery.
- **CED re-powering:** the capacity of the existing CED power plant was doubled to 50 MW via the installation of a second simple-cycle gas turbine.
- **CEC construction:** this involved the development of a new 300 MW power plant (open-cycle gas turbine) in the Djéno area near the CED facility. The power plant was commissioned in 2010. A third gas turbine, adding 170 MW, was commissioned in 2020. The CEC power station supplies energy to the entire municipality of Pointe-Noire, and the excess electricity is transmitted to the city of Brazzaville via a recently upgraded high-voltage network.
- **Gas reinjection program:** a program was developed to reinject excess gas while optimizing reserve recovery from the oilfield.

Outcomes

Flare reduction

The flaring reduction project of the M'Boundi field was completed during 2015, achieving the zero routine flaring target in the area. The key objective of the project was gas valorization through power generation and access to energy. In particular, the associated gas was fully monetized through a program of gas injection in order to optimize reserve recovery, and a long-term supply contract with power plants in the area including the CEC plant (Eni's interest is 20%). The M'Boundi integrated project was a key part of Eni's strategic objectives to reduce its gas flaring worldwide by 80% by 2015 with respect to a 2007 baseline.

Figure A3 Electricity generation by source in the Republic of Congo, 2005–2018 [22]



Other benefits

When power generation is based on associated gas that had previously been flared on a routine basis, the project creates social value as well as an environmental benefit. Unwanted flaring is reduced, and the additional electricity supply contributes to the economic development of the country. Integrated access to the energy project is ensuring access to affordable, reliable, sustainable and modern energy (SDG 7), and helping to build resilient infrastructure, foster innovation and promote inclusive and sustainable industrialization (SDG 9). Figure A3 shows the growth in electricity generation by source, reflecting, in part, the impact of the CEC and CED projects. As well as providing environmental benefits by reducing gas emissions, the energy program has enabled the success of the Hinda Project, which supplies electricity generated by solar panels to 33 community facilities (11 health centers and 22 drinking water wells).

Eni collaborated with the Politecnico di Milano to develop and validate the Eni Impact Tool[23] to measure the impact of the CEC project and its direct and indirect effects. The analysis concluded that the project improved the living conditions of the local population. The survey involved families, schools, hospitals and manufacturing and commercial activities in 38 neighborhoods. The CEC plant has been active for 10 years and the city of Pointe-Noire has benefited from the electricity supply, ensuring greater access to energy for its inhabitants.

[22] Source: IEA Electricity Information, 2020. https://www.iea.org/subscribe-to-data-services/electricity-statistics

[23] The Eni Impact Tool is used to evaluate the overall quality of the project (such as continuity of supply and voltage stability) and how it impacts the quality of life of the community through specific metrics

PETRONAS: FLARING REDUCTION PROJECT

Summary

In an existing offshore legacy field producing low-pressure associated gas, PETRONAS has implemented novel, low-cost surface jet pump (SJP) technology to recover flare gas, where the use of a conventional booster compressor had been commercially challenging due to limited deck space. The first-ever application of the SJP technology by PETRONAS began in 2019. Since then, it has been successfully tested for capturing 5–7 million scf/day of associated gas (100%) that had been flared routinely from the source wells.

Background

The gas industry in Malaysia incorporates all components of the complete value chain. Offshore, gas is produced by upstream companies under production-sharing arrangements with PETRONAS, the national oil and gas company. The downstream sector of Malaysia's natural gas industry consists primarily of domestic consumption and exports of LNG.

A Gas Master Plan Study commissioned by PETRONAS in 1981 set the roadmap for the development of a natural gas-based economy. It led to the implementation of the Peninsular Gas Utilization (PGU) transmission grid, which has facilitated the construction of more than 10,000 MW of installed power generating capacity, and enabled PETRONAS Chemicals to become one of South East Asia's largest integrated gas-based chemicals producers. Further downstream, the PGU grid feeds into the Natural Gas Distribution System, where gas is piped to retail (mostly industrial) customers. Gas exports to Singapore also flow through the PGU grid.

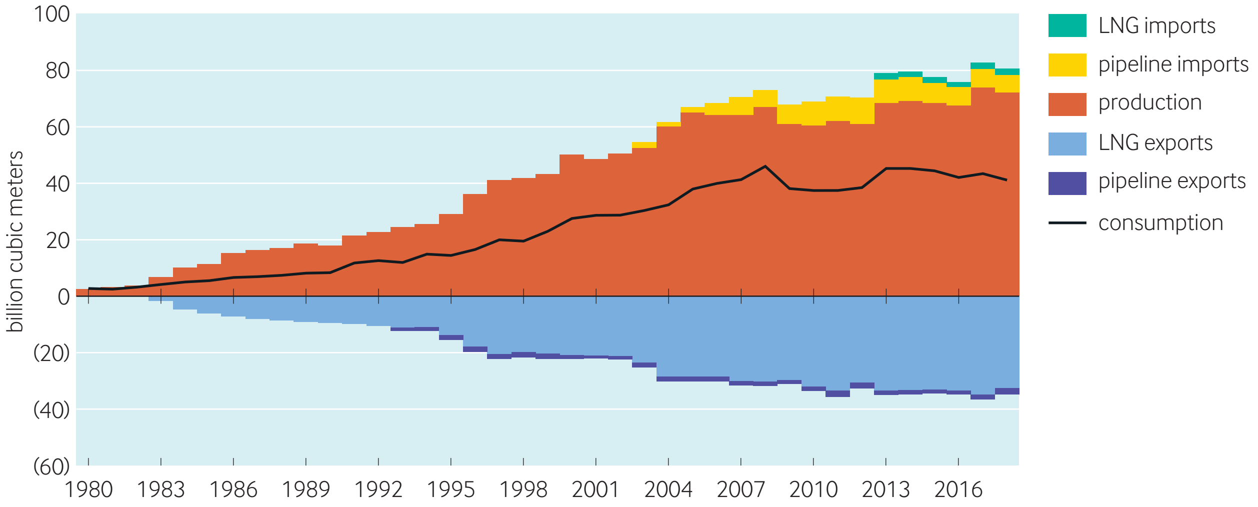
Embedded in the Malaysian government's energy and economic policies is the view that the natural gas infrastructure and gas-based industries enable national growth and sustainable development. The Petroleum Development Act, 1974 vested in PETRONAS the ownership and exclusive rights of exploring petroleum in Malaysia, and provides PETRONAS with the rights to issue licenses for contractors to commence and continue any business or service pertaining to upstream activities.

Recently, as gas production has declined to a level that is unable to satisfy domestic demand in Peninsular Malaysia, steps have been taken to open the gas market in Malaysia. The government, via the New Energy Policy 2010, the 10th Malaysia Plan and the Economic Transformation Programme, introduced the concept of the 'third-party access' system. Aimed at enhancing the security, reliability and sustainability of the gas supply in Malaysia, the goal is to have gas consumers benefit from competitive prices, better services and enhanced sustainability that comes from third-party access to the gas infrastructure and from market competition.

PETRONAS acts as the national regulatory body through Malaysia Petroleum Management, which is entrusted as the governing body for upstream activities in Malaysia. All operators must comply with the requirements stipulated by PETRONAS. Although there is no specific regulation by the national government on flare reduction, PETRONAS has imposed certain requirements. All new projects are required to operate a policy of zero continuous flaring and venting. For existing facilities, flaring and venting limits are applicable, and efforts to eliminate such activities must be pursued to achieve emissions targets. For both new and legacy operations, routine flaring is allowed temporarily (one day) and all flaring of associated gas must be reported to the government at a regular frequency, with volumes measured by flow meters.

Natural gas plays an important role in Malaysia's energy mix, accounting for more than 40% of the primary energy supply in 2018. However, Malaysia is among a small number of countries that both import and export LNG (see Figure A4 on page 105).

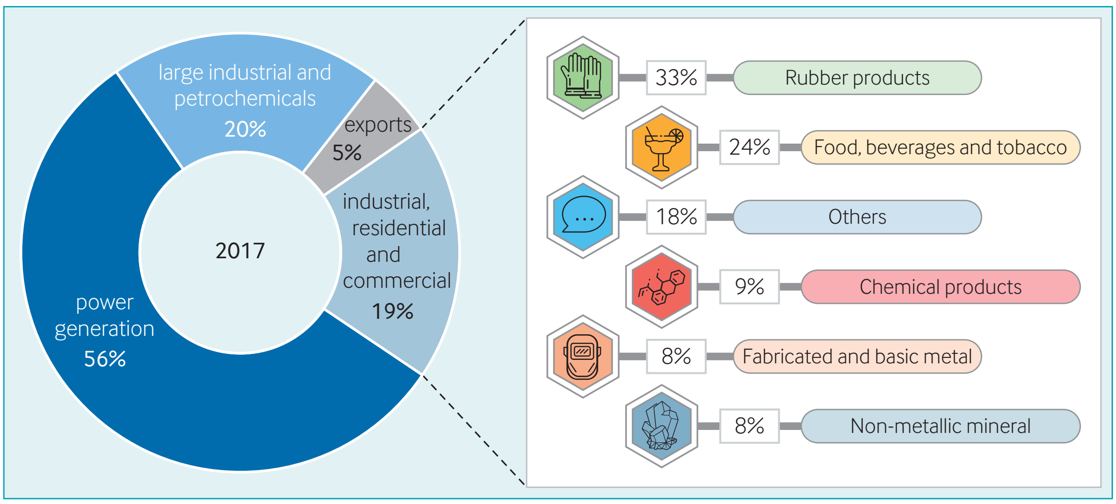
Figure A4 Supply and demand trend for LNG and pipeline gas in Malaysia, 1980–2016 [24]



In 2019 Malaysia exported 32.8 bcm from facilities located on the island of Borneo. It also imported 3.74 bcm of LNG to balance declining production from the gas fields around Peninsular Malaysia. This situation is the result of a geographical barrier; there is no pipeline connection between the LNG producing facilities and the regional demand markets.

Consumption of natural gas in Malaysia is spread across several sectors, with power generation being the largest (Figure A5, below).

Figure A5 Gas consumption in Malaysia in 2017 [25]



[24] Source: Gomes, I. (2020). *The dilemma of gas importing and exporting countries.* OIES Paper: NG 161. Oxford Institute for Energy Studies. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2020/08/The-dilemma-of-gas-importing-and-exporting-countries-NG-161.pdf

[25] Source: Malaysian Gas Association. https://malaysiangas.com/article-of-natural-gas

PETRONAS has deployed a broad spectrum of technologies to manage, recover and monetize gas resources, including in-field use within upstream operations, compression and distribution to gas consumers, power generation, and NGLs and gas-to-chemicals production. Despite a high level of awareness of such technologies, PETRONAS continues to seek new advances in associated gas utilization. This pursuit includes gathering outside (e.g. crowd-sourced) ideas for potential new solutions. For example, through a 2017 Technology Challenge presented to the global community, PETRONAS solicited ideas for the best economic solutions to monetize associated gas from offshore flaring facilities, and to reduce carbon footprint and intensity. More than 30 proposals were received.

Project description

Inevitably, as oilfields age, they experience a steady drop in reservoir pressure. This results in a reduced flow at the well head and, consequently, reduced production. In one particular offshore situation, the gas pressure was below the suction pressure of the existing compressor. To sustain production, the conventional approach would have been to lower the separator pressures, with the consequence of high flaring because of the compressor suction pressure limitation. Instead, PETRONAS implemented low-cost SJP technology to capture the produced gas.

SJP technology can be both a low-cost and high-reliability solution, with a better value proposition and greater potential for carbon footprint reduction compared with a conventional booster compressor. Based on Bernoulli's principle, SJPs use high-pressure fluid as the motive force to boost the pressure of produced gas. The high-pressure fluid passes through a nozzle, where part of the potential energy (pressure) is converted to kinetic energy (high velocity). The pressure of the fluid drops in front of the nozzle, and it is at this point where the low-pressure gas source connection is made.[26]

The project involved multiple offshore wells producing oil with an API gravity of 55–60 at a GOR above 10,000 scf/bbl. Total gas throughput was 5–7 million scf/day, with variations of up to 25%, as measured by a flow meter on the flared gas line. The gas was primarily methane, with < 2% higher-carbon hydrocarbons (C_5+), low concentrations of inert components and no H_2S.

Commercial use of the first-ever application of the SJP solution began in 2019. It achieved a 100% reduction in flaring. Nearly all (99%) of the gas captured by the SJP is recycled back to main gas compressor suction from where it is then sent off-site as pipeline quality gas for sale to third parties. The remainder is used as fuel to provide field power.

From inception to start-up, the project was implemented within 12 months, with half of that time being allocated to construction on the offshore platform. The total project commitment was less than USD 1 million, mostly capital, and was financed internally. Ongoing maintenance is expected to be minimal because no rotating machinery is involved. The company expected to achieve payback within one year.

The project was driven by PETRONAS' policy that seeks to eliminate all routine flaring and reduce overall GHG emissions. The first step in the project was the formation of a multidisciplinary working-level team of asset and subject matter experts within the organization for reviewing/studying present system performance with available offshore infrastructure. A key requirement was maintaining the capacity of the existing compressor on the platform. The team began by brainstorming, 'solutioning', simulating and evaluating various options. Those that were deemed to be infeasible included reinjection into the reservoir and greater in-field gas usage. After selecting the SJP solution, the project was sanctioned, and detailed design, installation and commissioning took place. Major project risks and mitigation strategies associated with the project were the availability of the motive gas pressure sourced from the compressor, uncertainty of the oil and gas sales price, and the suitability of the compressor performance curve.

[26] Carpenter, C. (2014). *Surface Jet Pumps Enhance Production and Processing.* Article published on the Journal of Petroleum Technology website on 31 October 2014. https://jpt.spe.org/surface-jet-pumps-enhance-production-and-processing

Outcomes

PETRONAS views this project as one that represents a breakthrough achievement. It is the first experience of using an SJP to recover the low-pressure gas into the main compressor suction and reduce flaring. It sets an example of how low-cost, high-reliability technology can be used to enhance oil production and facilitate the monetization of flared gas. The project is a testimony on sustainable development, where positive economic returns and beneficial environmental outcome (reduced carbon footprint as well as lower NO_x and other emissions) go hand in hand. It supports SDG 12 (Responsible consumption and production), SDG 13 (Climate action) and SDG 9 (Industry, innovation and infrastructure).

QATARGAS: JETTY BOIL-OFF GAS PROJECT

Summary

In 2014, Qatargas commenced operations at the Jetty Boil-Off Gas (JBOG) Recovery Facility at Ras Laffan Port in Qatar. This facility collects BOG from LNG ship loading operations and compresses it at a central facility. The compressed gas is then sent to Qatargas LNG trains to be consumed as fuel or converted into LNG. As a result of the JBOG recovery facility, flaring at the Qatargas LNG loading berths was reduced by more than 90%, saving approximately 29 bcf of gas per year.

Background

Qatar has about 12% of the world's proven reserves of natural gas. With the third largest reserves in the world, Qatar is committed to developing its natural gas resources for export markets. At the same time, the government, through the Qatar National Vision 2030, is pursuing economic diversification, renewable energy and environmental protection, among other significant initiatives.

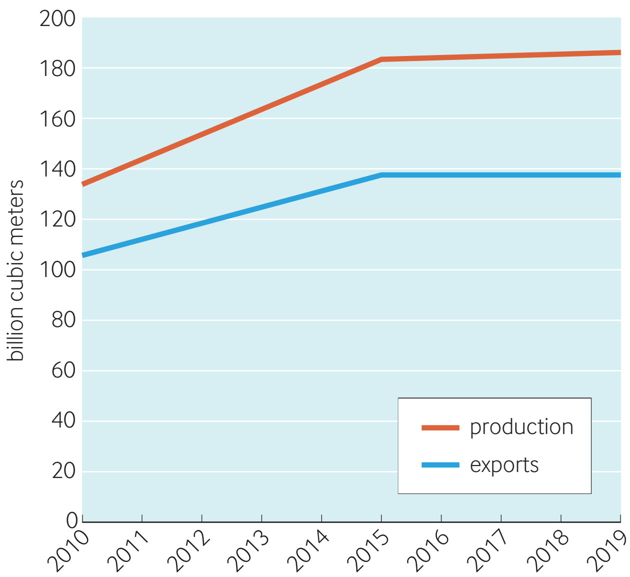
The Ministry of Energy Affairs exercises regulatory administration of the energy sector, covering both oil and gas production, operations and distribution. Qatar Petroleum (QP) is Qatar's national oil company. QP's affiliated gas operating company, Qatargas, manages all of Qatar's 14 LNG trains with a total annual production capacity of 77 million tonnes. Qatargas is the largest LNG producer in the world.

Article 29 of the 2003 Constitution provides that all natural wealth and resources, including oil and gas, belong to the state. The Ministry of Energy Affairs is the primary regulator of the oil and gas sector. Qatar has put into place numerous laws regulating its natural resources. Law No. 10 of 1974 (as amended by Law No. 15 of 1988) established QP as the national oil and gas company.

QP acts as the commercial arm of the government with respect to its rights in exploration, development, production and transport agreements. Other important laws governing oil and gas and environmental protection are summarized below.[27]

- Law No. 4 of 1977 on the conservation of petroleum resources and the conduct of petroleum operations within Qatar (Preservation of Petroleum Wealth Law).
- Law No. 3 of 2007 addressing the exploitation of natural wealth and resources, which includes not only mining but also oil and gas, and any associated operations (Exploitation of Natural Resources Law).
- Decree Law No. 30 of 2002 for the protection of the environment (EP Law) addresses conservation of the environment, pollution prevention, and protection of biodiversity and human health. The EP Law is further supplemented by its Executive Regulations of 2005. The Ministry of Municipality and Environment (MME) is the regulator for the oil and gas sector and other industrial sectors in the State of Qatar. It is a regulatory requirement for Qatargas' LNG jetty operations to recover a minimum of 90% of BOG flared during ship loading.

Figure A6 Gas production and export trends for Qatar, 2010–2019[28]



Natural gas plays an important role in Qatar's energy mix, accounting for approximately 90% of the primary energy supply. Qatar produced more than 185 bcm of natural gas in 2019 and exported more than 135 bcm via LNG shipments and the Dolphin pipeline, which connects Qatar to demand markets in the UAE (see Figure A6). In addition to LNG and gas exports, Qatar has a well-integrated supply chain of gas processing facilities, which provide domestic gas for in-country industry and production of fuel additives, chemicals, fertilizers and petrochemicals. It has world-scale GTL facilities, as well as facilities for ammonia and urea production.

The Qatargas Flare Reduction Programme is an over-arching program that governs flare reduction activities at Qatargas. It allows for the implementation of measures to keep flaring to a minimum while maintaining process safety. The main drivers in flare reduction stem from the company's commitment to the Qatar National Vision 2030 and its Direction Statement. Multidisciplinary flare management teams have various roles, including: managing flaring data; conducting surveillance of 'bad actors', and raising, tracking and mitigating action items as necessary; revising and optimizing operational and reporting procedures where applicable; progressing operational reliability and maintenance-related initiatives where applicable; and assessing flare meter performance. Qatargas has invested in new projects utilizing existing systems, applied process and operational controls, and reduced flaring during turnarounds and trips. Some of the company's major flare reduction initiatives include the JBOG recovery facility, purge gas reduction at LNG mega-trains, passing valves monitoring programs, and the installation of gas interconnections at some of the LNG mega-trains to help divert gas to other operating trains instead of allowing it to be flared.

The above operational and engineering projects, including the JBOG recovery facility, implemented as part of the Qatargas Flare Reduction Programme, have resulted in a 76% reduction in flaring since 2011; this has resulted in annual gas savings of 55,000 million scf or the power consumption potential of more than 560,000 homes.

[27] Mahmood, S. and Early, M. (2019). *Oil and gas regulation in Qatar: overview.* Thompson Reuters Practical Law Country Q&A 5-525-5499 https://uk.practicallaw.thomsonreuters.com/5-525-5499?transitionType=Default&contextData=(sc.Default)&firstPage=true

[28] Source: IEA. https://www.iea.org/countries/qatar

Project description

Flaring during LNG operations is due to the fact that LNG evaporates when it encounters warm spaces or surfaces, generating BOG. At the Qatargas LNG loading berths, BOG is generated through vapor displacement from ship loading and vaporization. During the loading of an LNG cargo, a portion of the -160°C liquid vaporizes as it comes into contact with the warmer ship tank. Previously, this gas would be flared at the ship's berth because there was no outlet for the low-pressure gas.

Guided by Qatar's National Vision to produce and supply clean energy to the world, Qatargas introduced the JBOG Recovery Project to recover the flared BOG. Front-end engineering design (FEED) work was awarded in late 2007. Following detailed engineering, a 55-month construction phase and subsequent commissioning, Qatargas commenced operations at the JBOG recovery facility in 2014.

During the loading of LNG tankers, around 1% of the -160°C LNG evaporates due to the difference in the temperature of the LNG and the ship's tanks. The BOG, which is discharged from the ships at temperatures ranging between -80°C to -100°C, is collected via a large-diameter (34–60 inch) stainless steel header system. The gas is then routed to the heart of the JBOG facility — the central compression area (CCA). At the CCA, collected gas is compressed from 0.03 barg to 47.5 barg in two compressor trains (each with low-, medium- and high-pressure compressors) sized for 50% of the rated capacity of 163 tonnes of JBOG per hour. This is equivalent to the maximum amount of BOG generated by three ship loadings simultaneously. Low-pressure BOG collected from LNG ships is compressed at a central facility and then sent to LNG producers to be consumed as fuel or converted into LNG. With this installed capacity, the CCA can recover more than 90% of the total flared gases at LNG berths.

One of the significant challenges was that the original design of the LNG terminal had not included sufficient space to install a compressor, driver and associated equipment. This constraint led to a change in the design of the plant, which involved relocating all of the compressors to a central location, some 5 km away. The new concept relied heavily on the ships' BOG compressors to deliver the gas at a pressure high enough to enable the gas to be transported from the ships to the CCA.

Because the project was to be located in brownfield areas, construction logistics were difficult. About 1,500 piles had to be drilled to carry the load of the facilities. A laser scan survey of each area produced high resolution digital images, which were later incorporated into a 3D computer design model. This identified potential conflicts (especially those in the subsurface) and helped to streamline the project's timeline, generating cost savings.

Several other technical design innovations were implemented, as follows:

- Ultra-low differential pressure check valves: due to the considerable drop in pressure between the ship and the compressor, no existing check valve design was available that could handle the very low inlet pressures at temperatures ranging from -140°C to ambient temperature. A special tilting disk check valve was developed, which uses an ultra-light titanium disk shaped like an airfoil.
- Largest BOG compressor: the first stage BOG compressors, designed and built by GE Nuovo Pignone, are some of the largest in the world, and are capable of handling 163 tonnes per hour at very low suction pressures.
- Ultra-low temperature buckling pins: buckling pins are special pressure relieving devices used in applications where quick pressure relief is required. To protect the ship's LNG tanks from an overpressure scenario, the JBOG design incorporated buckling pin valves capable of operating in cryogenic conditions, with special seals and mechanisms to ensure their reliability.

Outcomes

The JBOG facility is a landmark project for the State of Qatar, representing one of the cornerstones of Qatargas' overall flare management strategy. Flaring due to JBOG operations was reduced by more than 90%, producing a net reduction of approximately 1.6 million tonnes of CO_2 per year. In total, the facility saves 29 bcf/year which is enough to generate ~750 MW of energy, or the amount needed to power approximately 300,000 homes. As the largest environmental project of its kind in Qatar, with an investment of approximately USD 1 billion, the project is a tangible demonstration of progress on Qatar's National Vision and National Development Strategy, and in achieving the expectations of SDG 13 (Climate action).

SHELL: OXYGEN REDUCTION CATALYST TO OPTIMIZE FLASH GAS RECOVERY

Summary

SWEPI LP, an affiliate of the Shell group of companies operating in the Permian Basin, installed technology to reduce oxygen concentrations found in oil tank vapors, thereby upgrading the gas to a level that met pipeline quality specifications for off-site sales. This allowed the gas to be monetized, reducing the volume of gas flared by 40% compared to prior operations. Due to its field-proven performance, high reliability, low maintenance, modularity and attractive economics, Shell[29] has continued to expand deployments of this technology.

Background

The Permian Basin is an oil and gas producing area located in West Texas and the adjoining area of south-eastern New Mexico. It covers an area that is approximately 250 miles wide and 300 miles long, and is composed of more than 7,000 fields in West Texas. Oil and natural gas is produced from depths ranging from a few hundred feet to five miles below the surface.

The greater Permian Basin accounts for nearly 40% of all oil production in the United States, and nearly 15% of its natural gas production. The basin has historically experienced two significant increases in unconventional (horizontal) drilling activities, first in the 2011–2014 period and secondly during the oil price recovery in 2016–2018.

During late 2019, activity levels began to fall as fundamentals weakened and investor pressure led to operators shifting focus away from production growth.[30] Oil and gas production rates and drilling activity began to recover in 2020 and the trend has continued into 2021.

The Permian Basin has experienced a significant increase in natural gas flaring and venting in recent years, driven by a combination of higher activity levels, more production from areas with less-developed gas gathering infrastructure, and basin-wide take-away capacity bottlenecks. Flaring in the Permian Basin in Texas and New Mexico peaked in 2019, averaging more than 0.75 bcf/day.[31] Flaring volumes subsequently declined as the effects of a global supply-demand imbalance worked their way through the oil markets.

Within the Texas portion of the Permian Basin, event-driven flaring makes up more than 56% of total flaring. Temporary (< 1 year duration) routine flaring contributes 26%, long-term (> 1 year duration) routine flaring comprises 11%, and operational flaring from best-in-class operations accounts for the remaining 7%.[32] This means that most flaring is the result of issues at the well site or in midstream facilities, and these events and the subsequent flaring multiply when the overall gas infrastructure is running at or near maximum capacity. Variations in flaring have been driven by a number of factors including operator economic considerations, insufficient midstream infrastructure capacity, and varying regulations.

[29] In this case study, 'Shell' refers to SWEPI LP, an affiliate of the Shell group of companies operating in the Permian Basin.

[30] Rystad Energy and EDF (2021). *Permian Basin Flaring Outlook. Condensed Report.* January 2021. http://blogs.edf.org/energyexchange/files/2021/01/20210120-Permian-flaring-report.pdf

[31] https://www.houstonchronicle.com/business/energy/article/Permian-natural-gas-flaring-lowest-in-a-decade-as-15873536.php

[32] Rystad Energy and EDF (2021). *Permian Basin Flaring Outlook. Condensed Report.* January 2021. http://blogs.edf.org/energyexchange/files/2021/01/20210120-Permian-flaring-report.pdf

There have been a variety of US federal agency regulatory initiatives, legal challenges and court decisions regarding national-level control of venting and flaring during the 2016–2020 period.[33,34] The net result is that the primary regulations covering flaring of associated gas are those that exist at the state level.

In Texas, the Texas Railroad Commission (RRC) has jurisdiction over venting and flaring with respect to the prevention of waste of natural resources, and is the authority for granting requests by operators to flare associated gas.[35] The Texas Commission on Environmental Quality holds the authority to issue permits[36] for air emissions produced by flaring, and to establish technology requirements[37] and options for new flares and vapor combustion operations.

The RRC's Statewide Rule 32[38] allows an operator to flare gas while drilling a well, and to flare for up to 10 days after a well's completion to conduct well-potential testing. Rule 32 also allows an operator to request an exception to flare gas in certain circumstances. The majority of requests for exceptions received by the Commission are for flaring associated with casinghead gas from oil wells. Flaring of casinghead gas for extended periods of time may be necessary if the well is drilled in areas new to exploration where pipeline connections are not typically constructed until after a well is completed and a determination is made about the well's productive capability. Other reasons for flaring include gas plant shutdowns, compressor repairs, or maintenance being carried out on gas lines, wells or other facilities. In existing production areas, flaring may also be necessary because existing pipelines have reached capacity.

RRC staff issue flare exceptions for 45 days at a time, for a maximum limit of 180 days. Extensions beyond 180 days must be granted through an RRC Final Order. In 2019, 6,972 venting and flaring exceptions were issued statewide by the RRC, compared to 651 in 2011, which was before the widespread use of horizontal drilling and hydraulic fracturing began in the Permian Basin. Shell requested fewer than 50 short-term exceptions (< 60 days duration) in the 2018–2020 period; these were due to extended flowback operations or to complete mechanical repairs on vapor recovery systems.

State agencies in Texas have adopted regulatory requirements to drive gas utilization, and are working with oil producers to limit the need for flaring without shutting down or affecting crude oil production. In February 2021, the Texas Methane & Flaring Coalition (TMFC)[39] issued a report detailing a statement supporting a goal to eliminate routine flaring by 2030. Shell is a member of the TMFC and is supportive of the goal to eliminate routine flaring by 2030. Shell is also committed to the 'Zero Routine Flaring by 2030' initiative.

The Permian Basin has experienced steady growth in gas production since the onset of the unconventional/ tight oil era (see Figure A7 on page 112).

33 US EPA. Actions and Notices about Oil and Natural Gas Air Pollution Standards. https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/actions-and-notices-about-oil-and-natural-gas

34 US Department of the Interior, Bureau of Land Management. Methane and Waste Prevention Rule. https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/operations-and-production/methane-and-waste-prevention-rule

35 https://www.rrc.texas.gov/about-us/faqs/oil-gas-faqs/flaring-regulation/

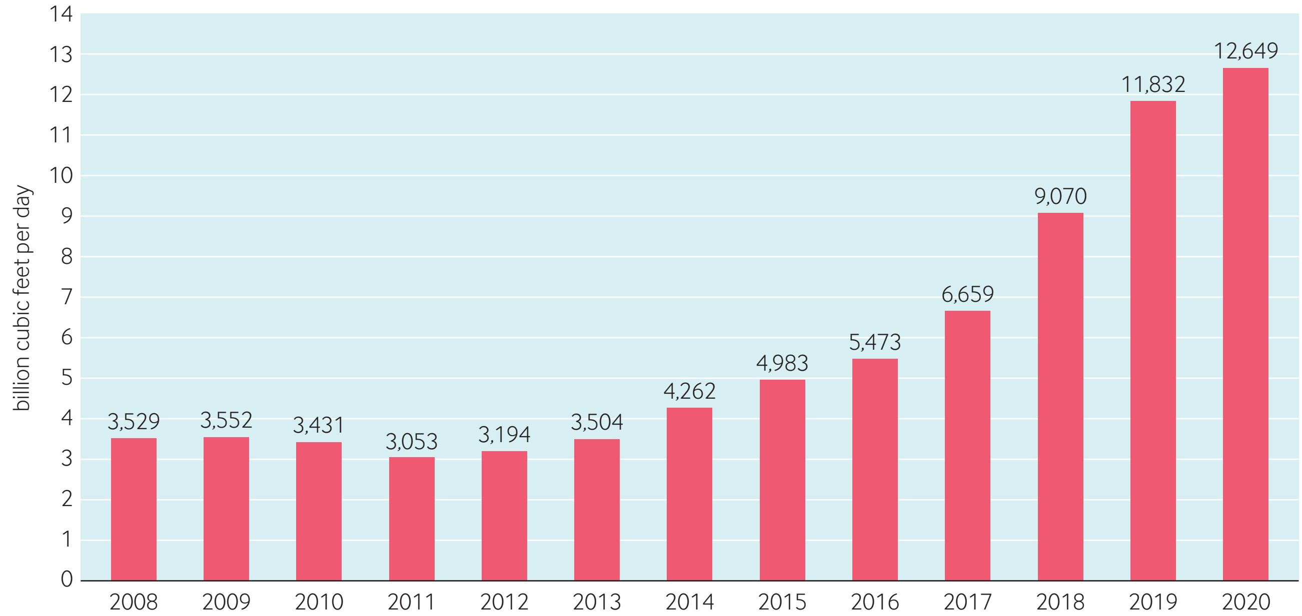
36 https://www.tceq.texas.gov/permitting/air/guidance/newsourcereview/flares/nsrauth_flares.html

37 https://www.tceq.texas.gov/permitting/air/guidance/newsourcereview/flares/nsr_fac_flares.html

38 Texas Administrative Code, Title 16, Part 1, Chapter 3, Rule §3.32. https://www.law.cornell.edu/regulations/texas/16-Tex-Admin-Code-3-32

39 The Texas Methane & Flaring Coalition, which includes seven trade associations and more than 40 Texas operators, was formed to develop industry-led solutions designed to mitigate and reduce methane emissions and flaring. www.texasmethaneflaringcoalition.org

Figure A7 Historical gross gas production in the Permian Basin[40]



Gas production has grown significantly during the past 8 years, with average production volumes rising from approximately 3.2 bcf/day in 2012 to more than 12.6 bcf/day through 2020. Much of the growth is attributable to associated gas.

Consumption of natural gas in Texas is spread across several sectors, with delivery to other states representing about 30%, industrial uses and power generation each representing about 21%, international exports 18% (and growing), and residential, commercial and other uses covering the remaining 10%.

Shell employs a comprehensive approach to environmental protection. It operates its shale oil and gas assets with the goal of eliminating routine venting or flaring of associated gas that takes place due to limited market capacity, and minimizing the volume of gas flared for safety, environmental or emergency situations.

Based on corporate standards, sites are advised to provide equipment and facilities to export, reinject or use the associated gas to eliminate continuous flaring. All potential options for gas utilization are considered, including the direct measurement of flare or vent gas flows, compressor optimization, gas-to-electricity conversion, gas to NGLs, and LNG production where appropriate. Operational best practices such as reduced facility start-ups to reduce flaring, leak detection, enhanced maintenance, and improvements in flare headers are also pursued. While some flaring may still occur for safety or emergency purposes, or due to lack of pipeline capacity, sites follow a flaring and venting management action plan when such activities are necessary.

Shell is part of the World Bank's GGFR and has endorsed the 'Zero Routine Flaring by 2030' initiative. This commitment to end the disposal of gas by flaring informs Shell's approach to identify ways to use associated gas from oil production to achieve positive outcomes for local communities.

[40] Source: Texas Railroad Commission Production Data Query System https://www.rrc.state.tx.us/resource-center/research/research-queries/

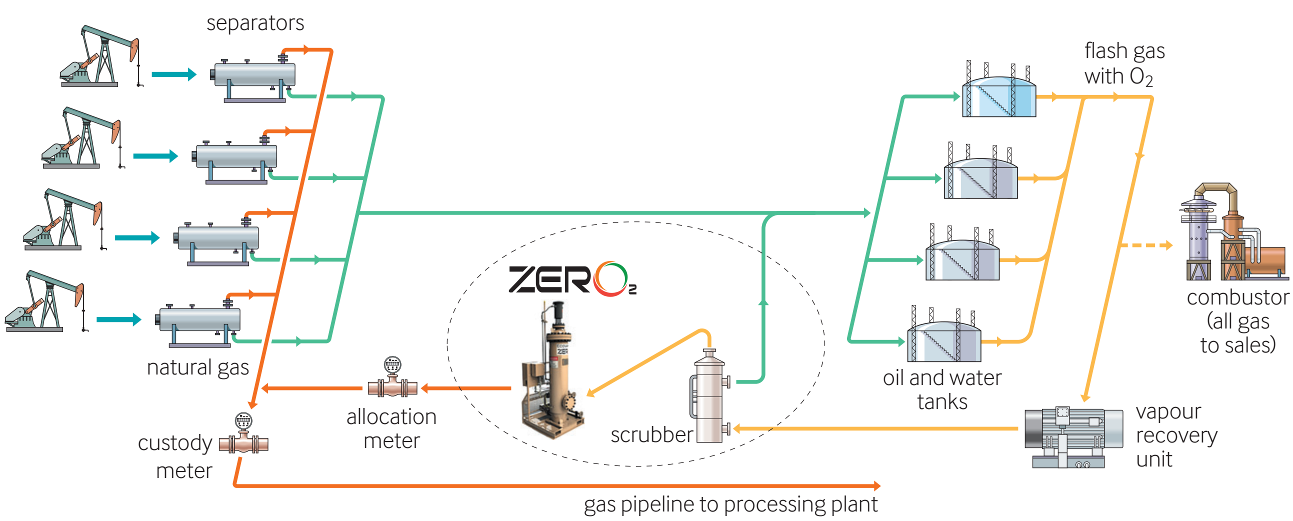
Project description

For operations in the Permian Basin, tank storage of produced oil prior to sale can be found at multi-well pads, gathering facilities or central processing facilities. Many oil and gas producers have adopted the use of oil storage tanks with sealed hatches to help prevent the venting of emissions. In a sealed tank, vapors accumulate between the liquid surface and the top of the vessel, causing tank pressures to increase. This pressure presents a potential safety risk when hatches are opened and can also cause fugitive emissions from thief hatches, seals or connectors. Since the tank vapor is rich in hydrocarbons, it is often profitable to implement recovery options and sell the gas to market. Doing so enables the tank pressures to be reduced and mitigates safety risks. However, if the oxygen content of the tank vapor gas exceeds pipeline specifications, the gas must be flared.

Collecting the hydrocarbon-rich vapor from the tank headspace and sending it to a flare or vapor combustion unit destroys the potential value of the gas and results in GHG and other emissions to the air. A commonly used alternative method is to recover a portion of the flash vapor in a low-pressure vapor recovery tower combined with a VRU. This system partially de-gases the produced oil prior to entering the storage tanks, and can reduce flaring but may not consistently produce gas that meets the pipeline specifications for oxygen (typically a maximum of 10 ppm).

As part of its commitment to flare minimization, Shell sought a more reliable and effective solution to reduce flaring and improve vapor recovery performance. It selected the EcoVapor ZerO_2 technology to operate along with VRUs. The intent was to help reduce flaring and GHG emissions by capturing and monetizing the tank and loading truck flash gas. When added to a typical oil gathering and tank storage site, the ZerO_2 system (see Figure A8) enables a low vapor pressure to be maintained in the storage tank systems without the need for a continuous flare. Using a precious metal catalyst in a reactor vessel, oxygen is converted to approximately equal parts of CO_2 and H_2O, which remain in the gas stream. The resulting low-oxygen, high-Btu gas can be injected into the gas sales line. EcoVapor estimates that, for a typical 2,800-Btu gas stream, the ZerO_2 system results in 0.169 tonnes of CO_2e captured per thousand scf processed at a cost of USD 0.81 per tonne. This nominal cost is offset by the increased sale of hydrocarbons (primarily NGLs), which are diverted from the flare and injected into the sales line.

Figure A8 Typical application of the EcoVapor ZerO_2 technology[41]



[41] Source: adapted from CEMS presentation: https://coems.org/wp-content/uploads/2021/01/2021-February-CEMS-Presentation-Notes.pdf

Features of the $ZerO_2$ units that Shell found attractive include:

- a significant reduction in oxygen concentration (from 3.5–5.0% inlet to 0–5 ppm outlet);
- the elimination of a continuous flare operation;
- a good (one-year) catalyst life, with a catalyst that can be regenerated;
- a 4:1 turndown ratio;
- a low pressure drop across the reactor unit, and low power consumption;
- a small footprint and quick installation; and
- simple maintenance (no moving parts) and high availability (a runtime of more than 99.5%).

In its initial work with EcoVapor in 2019, Shell chose operations with wells in the Delaware Basin portion of the Permian Basin. Oil produced from hydraulically fractured wells had an API gravity in the range of 42–52, with a GOR of approximately 100. The methane concentration of the associated gas was 15–30 mol%, and pentanes plus higher-carbon hydrocarbons (C_5+) were in the range of 7–13%. Production in the asset was growing — the gas volume captured during the project was 3 million scf/day on an annualized basis.

EcoVapor $ZerO_2$ units were installed at multiple facilities over a two-year period. The total project commitment was approximately USD 10 million. Based on the success of the initial test, which included a 40+% incremental reduction in the volume of gas flared, Shell deployed additional units. By the end of 2019, a total of 32 $ZerO_2$ units were in service, comprising a combination of small-capacity (0.3 million scf/day) and large-capacity (1.2 million scf/day) units.

Outcomes

At the Permian unconventional oil asset, Shell has carried out operational upgrades that remove flares from well pad design, and has invested in new technologies to improve the reliability of vapor recovery systems. Due to the field-proven performance, high reliability, low maintenance, modularity and attractive economics associated with the EcoVapor $ZerO_2$ technology, Shell has continued to expand deployment of these units, incorporating the technology as a component of the standard design for central processing facilities in the Permian Basin. The solution gave Shell a scalable, efficient and reliable method for processing increasing volumes of flash gas generated from the continued development of its Permian Basin asset.

By adopting this technology, Shell's operations eliminate the flaring (or incineration) of flash gas by capturing 100% of tank vapors, compared to typical efficiency levels of 60–80% for competing solutions. As a result, field facilities are more easily able to meet federal and state air emission requirements; this allows more wells per pad to be completed under existing permits, and yields a better environmental outcome. Other benefits have also been realized, including:

- increased gas sales volumes and enhanced sales of liquids (due to the incorporation of high-value tank vapor), which were previously lost by flaring; and
- the active management of tank battery pressure, which yields safety benefits.

WINTERSHALL DEA: WELL TESTING GAS CAPTURE PROJECT

Summary

In Argentina, Wintershall Dea has successfully conducted production pilot projects in the Aguada Federal and Bandurria Norte blocks, which are part of the onshore Vaca Muerta shale play in the central Argentine province of Neuquén. The initial program began in mid-2015 with the drilling of eight wells. As part of the field development, the company implemented a project to connect the extended (i.e. long-term) well-test facility in Aguada Federal to a third-party gas treatment plant, requiring the construction of gas compression facilities and new pipeline capacity to completely eliminate routine gas flaring. Wintershall Dea has a long presence in Argentina, where it produces gas and oil from about 20 onshore and offshore fields.

Background

Figure A9 shows the production trend for natural gas in Argentina. By the end of 2020, Argentina's production of natural gas was 0.131 bcm/day, or 4.63 bcf/day. Shale gas production accounted for 0.0325 bcm/day (1.14 bcf/day) of the total and is growing. However, Argentina has relied on LNG imports to help satisfy the demand for natural gas in the winter season.

The government of Argentina follows a federal structure with national-level ministries and independent provincial-level jurisdictions (provinces plus the autonomous city of Buenos Aires). Each jurisdiction has its own constitution and laws. For oil and natural gas, the federal regulatory authority is part of the Secretariat of Energy (Secretaría de Energía). Each province has authority to administer hydrocarbon resources within its boundaries.

Law No. 17.319 (1967), Law No. 26,197 (2006) and Law No. 27.007 (2014) contain the basic framework applicable to oil and gas exploration and production in Argentina. Due to declining production and increasing imports, Law No. 27.007 aimed to incentivize long-term foreign oil and gas investment, especially in shale oil and gas areas, such as the large Vaca Muerta reservoir in the Neuquén Province. Oil pricing is market-based, but there are provisions for reduced royalties when the business forecast for a given project indicates that production would not occur with standard royalties.

Through Decree 892/2020, Argentina formalized a new 'Gas Plan 2020–2024' to increase domestic natural gas production to 30 bcm by 2024. Other expected benefits include substantial fiscal savings, reducing or eliminating LNG and liquid fuel imports in winter, achieving an energy balance surplus and establishing a transparent, competitive system with market-based pricing.

Figure A9 Production of natural gas in Argentina, 2006–2020[42]

[42] Source: IAE (Argentine Energy Institute) Secretariat

Prior to the new Gas Plan, the government of Argentina set out the gas venting limits and requirements in Energy Secretariat Resolutions No. 236/1996 and No. 143/1998. The national rules encourage the utilization of associated gas, setting specific conditions on the allowable use of flares. Some provinces have issued other specific flare and vent rules. In Neuquén province, regulations prohibit gas venting in exploration wells and during production operations at gas wells, as well as limit emissions to air at oil wells. Flaring and venting activities are addressed by Provincial Law No. 2.175. For new fields, flaring and venting during the well testing and appraisal period is limited to three months. After that, wells with routine gas flaring must be shut in, unless specific permits are issued. Short-term exceptions are permitted under certain circumstances, and released gas must be incinerated. Longer exceptions are allowed for lower-pressure wells where operators have prepared a feasibility study with a schedule for abatement investments and made a financial commitment for those projects. The government imposes taxes/fees for routine and non-routine gas flaring.

The government of Argentina requires operators to report gas flaring volumes based on measured flows. It also publishes statistical data on oil and gas production, GHG emissions and flares. The flare data are derived mainly from thermal satellite imagery, and are used to provide information related to undeclared (i.e. not authorized) flare points.

Argentina is predominantly a natural gas-based economy; it is the leading source of energy, representing more than 50% of the total supply, and provides the majority of fuel used by power generation facilities. Well-developed electricity and oil and gas transportation systems cover the country. A specialized regulatory body — ENARGAS — is responsible for the transportation and distribution of natural gas. Under the new Gas Plan, the regulatory structure has been modernized. At the same time, and supported by the success of the Vaca Muerta play, Argentina has seen natural gas surpluses during the summer, which are mostly exported by pipelines.

In view of Argentina's existing gas transportation infrastructure and a growing demand for pipeline quality gas, monetization via compression and pipeline transport was the most logical alternative to flaring. Other options (NGLs, direct power generation, LNG, etc.) entailed higher costs, more challenging logistics or unattractive business cases.

Project description

As part of the field development at the Vaca Muerta shale play, Wintershall Dea implemented a project to connect an extended (i.e. long-term) well-test facility to a third-party gas treatment plant to completely eliminate routine gas flaring. The testing facility handles multiple hydraulically fractured oil wells (API gravity = 45) at an average GOR of 140. Approximately 2.5 million scf/day of associated natural gas (70% CH_4 with less than 5% C_5+) is produced at ~45 psig.

Prior to implementing the flare reduction project, no infrastructure (i.e. gathering system, compressors, pipeline, etc.) was in place to route the associated gas to a distribution pipeline system. Wintershall Dea constructed a new gas compressor and export pipeline to facilitate gas take-away. The project took 18 months from inception to start-up, with approximately half of that time used for construction of facilities and pipelines. The total project investment was between USD 10–15 million. More than 90% of the captured gas is eventually sold into the regional gas market. The remainder is used within the field. The new facilities are expected to have a long operational life; ongoing costs for routine compressor maintenance and pipeline pigging are expected to be minor.

The project is an example of the company's public commitment to end routine flaring and to the 'Zero Routine Flaring by 2030' initiative. Backed by an internal policy, and a specific process to identify flare reduction and gas monetization and utilization projects, Wintershall Dea has implemented flare reduction projects in its other operating locations, including gas to power for both captive use and for export, production of pipeline quality gas, and NGL production.

Worldwide, the company has also undertaken steps to enhance operating practices, including direct measurement of flare or vent gas flows, balancing production and reducing start-up time to reduce flaring, adding compression and improving compressor reliability, reduced pilot or ignitor gas consumption, and optimized vent systems and flare headers.

Outcomes

With operators increasingly targeting oil production at the Vaca Muerta play, the production of associated gas is growing, creating a risk that gas volumes may surpass regional pipeline and midstream capacity. The Wintershall Dea early well testing gas-capture project is an exceptional example of how private companies can implement practical solutions that provide commercial and environmental benefits.