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Associated Petroleum Gas Flaring Study for Tunisia

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

APG  associated petroleum gas
BBT  Bin Ben Tartar
BCM  billion cubic meters
bbl/d barrels per day
boe/day barrels of oil equivalent per day
CAPEX capital expenditures
CNG  compressed natural gas
CPF  central processing facility
EBRD European Bank for Reconstruction and Development
ETAP L’Entreprise Tunisienne d’Activités Pétrolières
GGFR Global Gas Flaring Reduction Partnership
GPP  gas processing plant
GTP  gas treatment plant
HSE  health and safety environment
IEA  International Energy Agency
IRR  internal rate of return
ktoe thousand tons of oil equivalent
LPG  liquefied petroleum gas
MMscfd million standard cubic feet per day
Mscfd thousand standard cubic feet per day
MW(h) Megawatt (hour)
NGL  Natural gas liquids
NOAA National Oceanic and Atmospheric Administration
PSA  Project Sharing Agreement
STEG Société Tunisienne de l’Electricité et du Gaz
STGP South Tunisian Gas Project
US  United States
US$/USD US Dollar
VIIRS Visible Infrared Imaging Radiometer Suite
Executive Summary

This report presents the main results from a Study commissioned by the European Bank for Reconstruction and Development on flaring of associated gas in Tunisia. The oil and gas market situation and business practices relevant for associated gas utilization has been reviewed, as well as the existing regulatory environment. A high-level review of the most viable alternatives for associated gas utilization has been conducted based on information from an examination of the flare situation in the country and three specific case studies have been conducted of possible flare reduction investments. The case studies are presented separately but a brief summary are given at the end of this report. The main conclusions from the Study are:

✓ According to estimates from satellite data flaring in Tunisia was at about 0.55 billion cubic meters (BCM) in 2014, against 0.65 in 2012. Some 80% of the flaring is at oil fields in the south of the country.

✓ Most flare sites in the south are small in flare volumes but will have relatively good access to tie-in for the gas or power produced locally from gas, in particular with commissioning of Nawara gas infrastructure project.

✓ Three main categories of associated gas utilization are particularly relevant in the case of Tunisia: i) Separation of the liquid components of the gas since liquefied petroleum gas are products in short supply in the country ii) transport of gas to a tie-in point (trunk-line or gas processing plant) when there is a short distances to such tie-in locations iii) displacement of diesel currently used for local power production with associated gas, and with possible export to the grid of power not needed at the field.

✓ An investment analysis have been conducted for three case of associated gas utilization; Bin Ben Tartar and Laarich both located in the oil province in the south, and Chergui located on Kerkennah Island. A range of gas utilization alternatives have been considered for these three cases including tie-in to a gas trunk-line, CNG transport, power production on-site and NGL recovery. The cases studies have demonstrated that it was technically and economically feasible to eliminate flaring at two of the sites considered. For the third case, the assessment concluded that partial gas utilization is economically feasible, however incremental solutions for additional use of the remaining associated gas was not financially viable with current energy prices.

✓ A rough estimate has been made of capital required in order to eliminate all existing routine flaring in Tunisia. The cases referred to above¹ are estimated to cost 85 million USD, but this represent only 30% total flaring in 2014. Other flare sites consist primarily of 14 fields with medium flare volumes (> 0.01 bcm/year) and representing 60% of total flaring. In addition there are some 25 fields with low flare volumes (< 0.01 bcm/year), representing 10% of total flaring. which having less than 0.01 bcm in annual flare volumes. It is difficult to estimate the capital expenditures for requirements. Limited information has been available in order make good estimates of flare reduction capital expenditures for other fields that those covered by the case studies. Excluding the offshore gas flares, The range of estimates for capital expenditures to eliminate all routine flaring is from 170 to 270 million USD including the 85 million USD for the three investments of the case studies. Costs for fields in the south are considerably lower per unit of captured gas as compared to flare elimination from offshore fields.

¹ Plus Cercina located offshore of Kerkennah Island
1. Introduction

This report summarizes the main findings from a project assignment, “Associated Petroleum Gas Flaring Study for Tunisia” (the Study), conducted by Carbon Limits for the European Bank for Reconstruction and Development (EBRD). The objective of the Study has been to review the flaring situation in Tunisia in terms of business practises, mid-term evolution as well as existing regulatory environment. Further, a high-level review has been made of the most viable alternative options for associated gas utilization relevant for the conditions in Tunisia. This has been done primarily through a detailed analysis for three flare sites and production concessions in Tunisia; Bir Ben Tartar and Laarich in southern part of the country and Chergui located on the Kerkennah Island in the east of Tunisia.

Techno-economic analyses of gas utilization options have been conducted for all three, in close cooperation with L’Entreprise Tunisienne d’Activités Petrolières (ETAP) who is the Tunisian state’s partner in the concessions.

Each case is summarized in Chapter 5 of this report. Prior to that Chapter 2 presents and brief overview of relevant framework conditions and institutions involved in the oil and gas sector and flare reduction efforts. Chapter 3 includes an overview of oil and gas supply and demand in Tunisia followed by a review of flare estimates for the country and their location. The flare estimates are partly from data of satellite images of flares and partly from information compiled by ETAP. Based on information from the case study analysis and review of flare data for the country Chapter 4 presents an overview of gas utilization options and technologies considered to be suitable for the situation in Tunisia. The report is concluded (Chapter 6) by a rough estimate of capital expenditures required in order to reduce flaring in Tunisia.

The Study should be seen as part of the broader aim of EBRD to contribute to international reduction in flaring of associated gas. EBRD collaborates with the Global Gas Flaring Reduction Partnership (GGFR), managed by the World Bank, to help initiate flare reduction investments. An initiative for “Zero Routine Flaring by 2030” was formed in May of 2015 and is actively supported by the World Bank and EBRD. The initiative brings together governments, oil companies, and development institutions recognizing that routine flaring is unsustainable from a resource management and environmental perspective. ETAP is among the companies that have endorsed the initiative.

2. Framework conditions and institutional structure

Key institutions

The Minister of Industry and Technology is the authority in charge of petroleum operations in Tunisia. The Ministry supervises the Direction Générale de l’Energie which manages and controls petroleum operations. The Comité Consultatif des Hydrocarbures gives advice on the granting of title to hydrocarbon permits and/or concessions. A key role is played by L’Entreprise Tunisienne d’Activités Pétrolières (ETAP) which is a state owned company in charge of petroleum operations.

ETAP was created in 1972 to manage petroleum exploration and production activities on behalf of the Tunisian government. In 2014, ETAP managed 46 exploration permits representing an investment of 350 Million USD.

Another relevant state company for this Study is the Tunisian electricity and gas company (STEG). Since 1962 STEG is responsible for production and distribution of electricity and natural gas. It operates the majority of installed electrical generation, transmission and distribution, as well as gas distribution.

Licensing conditions and Project Sharing Agreements (PSAs)

Under the Law n°99-93 (“Hydrocarbon Code”, 1999) that governs hydrocarbon prospecting, exploration and production, the State owns petroleum reserves. The Hydrocarbon Code covers the following licenses: i) prospecting authorization, ii) prospecting permit, iii) exploration permit, and iv) exploitation concession.

Exploration permits are only granted for applicants acting in association with ETAP. The terms and conditions of related operations are specified in a provisional agreement between the Tunisian State, ETAP and the contractor. Exploration and exploitation conditions are further detailed in accordance with two contractual regimes:

- **Joint venture contract:** when ETAP and contractor(s) are co-holders of the exploration permit and exploitation concession.
- **Production sharing contract:** when ETAP is the sole holder of the exploration permit and exploitation concession, and the contractor acts as an operator.

Under the joint venture contract, ETAP can take participating interest in the exploitation concession and must reimburse an agreed percentage of the prospecting and exploration costs. A production sharing contract entitles ETAP to a share of hydrocarbon production as agreed in the contract.

International oil and gas companies

The major international companies operating in Tunisia include BG Group, ENI, OMV, and Perenco. Currently domestic gas supply is dominated by the offshore fields operated by BG Group, which started its operations in Tunisia in 1989. It now operates two gas fields: Miskar and Hasdrubal, since 1996 and 2009 respectively. Produced gas is delivered to the company’s processing or LPG

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3 Source: ETAP  
5 Source: BG group
production facilities and then sold to STEG. BG Group is also involved in exploration in the Amilcar area in the Gulf of Gabe.

Eni has been operating in Tunisia since 1960. It operates five concessions, acts as a partner in four others and has several exploration permits in the south of the country. In 2013, Eni’s production in Tunisia amounted to 13,000 boe/day.

OMV has been active in Tunisia since the early 1970s. OMV is an operator in three different concessions and owns share in seven others. OMV Tunisia produced 10 000 boe/day in 2013 and plans to expand productions in the next few years. OMV and ETAP each have 50% shares in Serept, which operates three onshore and the Ashtart offshore fields.

Perenco acquired Tunisian assets in 2002 and now operates three concessions in Central Tunisia. In 2015, operated production amounted to 4500 boe/day. Output is either transported to the company’s central processing facility or transferred further for export (condensate). Gas is delivered to the Gabes plant for domestic consumption.

Other actors include Winstar, Lundin, Ecumed (Candax Energy), Viking and Storm (Medco Energy).

Regulation and policies

Gas flaring in Tunisia is not prohibited, but operators must obtain a permit from the government to flare. According to ETAP, such a permit is not granted for wells with high gas-oil ratios.

More generally on environmental protection, the Hydrocarbon Code obliges license holders to perform an environmental assessment to receive approval for the exploration and exploitation phase, as well as take all necessary measures to protect the environment and fulfil commitments provided in the assessment. The extent to which the environmental studies address flaring vary.

In addition, the Hydrocarbons code authorizes the holder of an operating oil concession to enhance the value of the gas of their plant by production of electricity and its related sale to STEG. Owners of gas fields may (up to a total amount of 40 MW):

- use gas to cover their requirements and sell their surpluses to STEG
- use non-commercial gas to generate electricity and sell it to STEG

According to communication with ETAP, regulatory and legal issues as a whole do not prevent flare-out projects. There are, however, some potential issues related to ownership of gas in the older blocks and the right to sell gas (including CNG) to users outside the grid.

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6 Source: ETAP
7 Source: ENI
8 Source: ETAP
9 Source: OMV
10 http://www.perenco.com/tunisia
3. Oil and gas supply, demand and flare situation

3.1 Oil supply and demand

Tunisia is a relatively modest hydrocarbon producer: in 2014, crude oil production was at about 53,000 barrels per day (bbl/d), with a distinct decline from 97,000 bbl/d in the 1980’s\(^\text{12}\), and an overall peak level of 118,00 bbl/d in 1980. Oil consumption increased steadily until 2005 and has since then been stagnant. Except for three years with high oil production after 2006, Tunisia has been a net importer of oil since 2003.

\[\text{Figure 1: Oil production}^{13}\text{ and consumption (1975-2014)}^{14}\]

3.2 Gas supply and demand

Gas production has increased steadily since the mid-1980s to reach about 2,800 ktoe\(^\text{16}\) (about 3.1 bcm\(^\text{17}\)) in 2013\(^\text{18}\). BG group\(^\text{19}\) is the largest producer of gas in Tunisia with more than 60% of the domestic gas production. Gas demand in the country exceeds supply and the gap has steadily increased over the past 15 years (Figure 3). The power sector represents about 70% of the gas consumed in Tunisia (Figure 4), while industry and other sectors (transport & residential/commercial) comprise respectively 18% and 11% of total gas consumption.

\[\text{Figure 2: Oil consumption by sector (2013)}^{15}\]

\(^{12}\) Source: BP Statistical review 2015
\(^{13}\) Source: BP Statistical review 2015
\(^{14}\) Source: IEA energy balances
\(^{15}\) Source: IEA energy balances
\(^{16}\) thousand tons of oil equivalent
\(^{17}\) billion cubic meters
\(^{18}\) Source: IEA energy balances
\(^{19}\) Source: http://www.bg-group.com/databook/2014/24/where-we-work/tunisia/
3.3 Flare situation

Most of the fields in Tunisia are located in two areas: offshore west of Tunisia and south in the desert (see Figure 7 and Figure 6).

Two sources of information have been used to assess the magnitude and location of flaring activities in Tunisia: (i) recently published\(^\text{22}\) satellite data for 2012-2014 collected and analysed by the US National Oceanic and Atmospheric Administration (NOAA) and (ii) flaring volumes per field estimated by ETAP.

\(^{20}\) Source: IEA

\(^{21}\) Source: IEA

\(^{22}\) In March 2015: [http://www.ngdc.noaa.gov/eog/viirs/download_global_flare.html](http://www.ngdc.noaa.gov/eog/viirs/download_global_flare.html). Earlier estimates of gas flaring volumes based on VIIRS (Visible Infrared Imaging Radiometer Suite) technology are available at NOAA’s website: [http://www.ngdc.noaa.gov/eog/viirs/download_viirs_flares_only.html](http://www.ngdc.noaa.gov/eog/viirs/download_viirs_flares_only.html)
Estimates based on satellite images (quantified by US NOAA\(^{24}\)) suggest that Tunisia has been flaring between 0.65 and 0.56 bcm of gas per year in 2012-2014, of which flaring at upstream facilities comprises over 96%. Figures above present the location and magnitude of gas flaring events for 2012-2014 based on satellite data.

Flaring volume are estimated (only to a limited extent based on measurements) and hence uncertain, according to ETAP. Nevertheless, ETAP data together with NOAA estimations facilitate understanding of the scale and geographical distribution of the flaring issue in Tunisia. According to ETAP, the Bir Ben Tartar field represents the largest contributor to gas flaring, followed by the Chourouq and Laarich fields. In terms of regional contribution, South of Tunisia constitutes by far the largest share of the total flared gas volume (around 80% in 2012-2014).

\(^{23}\) Source: NOAA satellite data
\(^{24}\) Source: http://www.ngdc.noaa.gov/eog/viirs/download_global_flare.html
Figure 7: Location of oil and gas fields and identified locations with flaring in 2012-2014 (NOAA data)
4. Associated gas utilization in Tunisia

4.1 Applicability of technologies in Tunisia

There are a number of technologies and approaches available for flare reduction efforts. Those being technically feasible and economical relevant depends on local conditions. Important determinant factors are:

i. Distribution/location of production facilities (e.g. well pads) within a site/license and short term variability of production which are important for gathering costs and required processing capacity;

ii. Gas composition, which is a determinant of the market value of the gas. Large share of heavier components that can be separated as liquids represent a potential for higher revenues;

iii. Impurities such as H₂S and CO₂ which can drive up costs for equipment and gas treatment;

iv. Low gas pressure which requires compression capacity in order to have the gas gathered, transported and processed

v. Long distance to infrastructure or markets which drives up costs for compression, transportation and processing.

vi. Remaining field lifetime and projected volume of gas available.

As shown in Chapter 3 above flaring in Tunisia currently happens at some 15, but field specific data have only been collected for 3 fields (see next Chapter). It has therefore not been possible to assess the whole population of flare sites against the criteria listed above. Still some general observations can be made on the characteristics of flaring in Tunisia with relevance for gas utilization and technology solutions:

a) Flare volumes are relatively small, ranging from 10 MMscfd to 1 MMscfd

b) A large share of the flare sites are located in the vicinity of gas infrastructure. This situation will become even better with commissioning of Nawara project (see below).

c) The amount of impurities is generally low and the share of heavier component relatively high so that NGL separation often is an economically attractive proposition.

Based on this three main categories of associated gas utilization seems particularly relevant for Tunisia:

- NGL separation which can take different forms in terms of costs and technological options. The option is attractive because LPG generally is in short supply throughout Tunisia.
- Transport of gas (with or without NGL separation) to a gas tie-in (GPP or trunk-line).
- Use of associated gas for local power production being used locally to displace diesel and/or for export to a grid or nearby load center.

In cases with modest gas volumes and long distance to infrastructure (typically > 25 km) treatment and transportation of the associated gas from the production site as compression (CNG), normally by trucks, can also be an option (see discussion under Bir Ben Tartar case in the next chapter).

The following table presents, for each gas utilisation categories, an overview of the typical investment costs, potential barriers and benefits.
<table>
<thead>
<tr>
<th>Category</th>
<th>Description</th>
<th>Typical investment(^{25})</th>
<th>Potential barriers</th>
<th>Revenue stream</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power for own use</td>
<td>Associated gas is captured and used for power and heat at the production site.</td>
<td>1 - 1.5 MMUSD/MW</td>
<td>• Low energy demand on-site compared to the gas volume available</td>
<td>Diesel substitution</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Field layout: Distribution of the flaring sites compared to the power demand</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Gas quality and supply variability</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Low energy demand on-site compared to the gas volume available</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>Field layout: Distribution of the flaring sites compared to the power demand</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Gas quality and supply variability</td>
<td></td>
</tr>
<tr>
<td>Gas delivery by pipeline</td>
<td>Gathering, pre-treatment and transportation of associated gas for export by pipeline for further processing and/or end use.</td>
<td>Collection and pre-treatment: 0.5-3 MMUSD/MMSCFD Pipeline: 0.4-1 MMUSD/km</td>
<td>• Distance to infrastructure</td>
<td>Gas sale</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Product quality requirements</td>
<td></td>
</tr>
<tr>
<td>NGL recovery and marketing</td>
<td>Gathering, C3+ or C5 + extraction and export normally by trucks or train.</td>
<td>1.5-16 mill USD/MMscfd processed(^{26})</td>
<td>• Gas quality variation and product quality requirement</td>
<td>NGL sale</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• LPG transport (in particular offshore)</td>
<td></td>
</tr>
</tbody>
</table>

4.2 The Nawara project

This project is important for improving the conditions for market outlets for associated gas in the south of the country. The project, officially called the South Tunisian Gas Project (STGP), involves installation of a central processing facility (CPF) at the Nawara well site for pre-treatment of gas, a 370km pipeline, and a gas treatment plant (GTP) in the Ghannouch industrial district near the coastal city of Gabès\(^{27}\). The CPF will have an approximate maximum capacity of 100 MMscfd and the line will have a capacity of around 350 MMscfd. OMV, the operator, expects first production to commence in 2016\(^{28}\).

The feasibility of gas utilization projects in the south is enhanced by the Qued Zar 16” gas pipeline that is now being installed. Associated gas will be collected from a number of fields and transported to Gabes for processing. It should be noted that while the gas link from the Djebel Grouz and Cherouq fields has been completed, the gas will continued to be flared until the Qued Zar transmission line becomes operational.

\(^{25}\) Typical range of investments based on (i) the 3 cases studies performed in Tunisia and (ii) the international experience of Carbon Limits on gas utilisation projects. Investment are really site specific and should be evaluated on a case by case basis.

\(^{26}\) Really variable depending on the technology selected and on the product quality expected

\(^{27}\) http://www.hydrocarbons-technology.com/projects/south-tunisian-gas-project-stgp-nawara-project/

\(^{28}\) http://www.omv.tn/portal/01/tn/omv-tn/omv-en-tunisie/activites/le-projet-de-developpement-de-nawara#
Figure 8: South Tunisia oil and gas infrastructure and Nawara components (CPF, Oued Zar – El Borma)
5. Summary of case studies

5.1 Chergui

Chergui is a gas-condensate field operated by Petrofac under a concession held by Petrofac (45%) and the state-owned oil company and Entreprise Tunisienne d’Activités Pétrolières, ETAP (55%). Current gas production is approximately 30 million standard cubic feet per day (MMscfd), which is treated at the Central Processing Facility (CPF) for export. Currently, around 0.5 MMscfd of low pressure and very heavy rich gas is being flared at the field, on Kerkennah Island.

Based on information provided by Petrofac and ETAP, several options for utilizing the currently flared and vented gas have been examined:

- **LPG cases.** Three different options for fractionation and exports to local or national LPG: (i) a large scale skid-mounted LPG plant to separate and export C3/C4, (ii) large scale “customized” C3 and C4 extraction, and (iii) skid-mounted LPG small scale plant for supplies of C3/C4 only to the local market.

- **Power cases:** The gas currently flared and vented has very high energy content and need to be blended with dry gas to allow power generation with existing technologies. The dry gas is from supplies currently exported from the island. Three alternatives of combined heat and power (CHP) investments are examined: i) using all the gas currently flared for production of power, of which a part will have to be exported to the main land, ii) using gas enough to generate power for the baseload winter demand on the Kerkennah island, and iii) using gas enough to generate power for the maximum summer demand on the island. All alternatives are capable of producing heat (through combined heat and power) that can be used for desalination purposes.

- **LPG and power:** A case combining LPG fractionation (small scale) and power production is also examined. In this case, C3/C4 and condensate are extracted and brought to a market. The remaining gas is blended with supplies currently exported dry gas to produce power. Power capacity is planned to satisfy the baseload winter demand on the island.

The main findings from the analysis are:

- **LPG cases:** Economically, the most attractive option is to process the associated gas and market a C3/C4 and distribute to the local and national market. The small scale option, using an LPG skid mounted unit, is less profitable and has lower environmental benefits as a large share of the initial flare volume will continue to be flared after project implementation. The customized C3 and C4 extraction is of course less attractive on a pure economic basis but present number of technical and operational advantages, in particular: (i) better control of the final product quality and (ii) larger flexibility in the composition of the intake gas.

- **Power cases:** With base case assumptions producing power does not seem very attractive. As the island is already connected to mainland and there is no need for additional subsea power cables, it seems that the most attractive option is to export the power.

- **LPG and power:** The combined case of small scale fractionation and power production is attractive but not as attractive as LPG production.
To conclude, Chergui field is expected to flare around 0.5 MMscfd of very rich associated gas at a stable rate. A part of the LPG can be marketed on the island and thereby partly displacing LPG and diesel currently imported from the mainland. The remaining of the LPG could be transported onshore. It is also important to add that results of this analysis are very sensitive to commodity prices and on the technology selected for the LPG separation.

5.2 Bin Ben Tartar

The Bin Ben Tartar (BBT) Concession is located situated in South East Tunisia, about 2.5 km west of the Libyan borders. MedcoEnergi, a private Indonesian company, operates the field under a Production Sharing Agreement with ETAP (L’Entreprise Tunisienne d’Activités Pétrolières). The field started production in 2009, and it is under further development. Currently, there is no solution in place for utilization of the low-pressure associated gas produced at the field. A number of gas utilisation options have been considered for BBT low pressure associated gas:

- **Option 1**: Recovery and on-site treatment of NGL (C3+) and exports to a nearby market.
- **Option 2**: On-site use of associated gas to substitute current diesel consumption.
- **Option 3**: Use the remaining associated gas for power production which is exported to the grid
- **Option 4**: Export the remaining gas as CNG to a nearby gas market or tie-in point.

The first two options represent only partial solution and would reduce the flaring by less than 20%. Option 3 and 4 represents incremental solutions (to option 1 or option 2) for additional use of the remaining associated gas. A detailed techno-economic assessment of the four options (and their combination) was performed and a number of conclusions can be drawn from this analysis. These results are primarily sensitive to the assumptions made on energy prices and the production profile for associated gas production:

- **Option 1**: Recovery of NGL represents an economically attractive partial solution for the associated gas currently flared. The assumed LPG and condensate prices are 350 and 430 USD/ton respectively. The IRR for option 1 is highly dependent on LPG prices.
- **Option 2**: The implementation of gas engine does not represent an economically attractive option. Conversion kit for existing diesel generators (to allow diesel- gas biofuel consumption) is being considered.
- **Option 3**: The economic attractiveness of additional power generation for export to the grid (option 3) is dictated by the price being offered as feed-in tariff. At current power price assumed to be paid for power supplies further investment in power generation capacity for exports is not financially viable.
- **Option 4**: The deployment of CNG Trucking, also known as “Virtual Pipeline,” has been identified as an interesting full gas utilisation solution. The solution is scalable, with room for optimization of the trucks. Nonetheless, this option presents several technical risks (HSE, road safety, security…) that should be evaluated more in detail during a feasibility study before moving on to this option. Commercial viability of this option should be also evaluated in more details. The results for option 4 relies a price for delivered dry gas.

In the current political and economic context, the project has however been delayed until the situation stabilise in the region.
5.3 Laarich

Laarich is an onshore field situated in the South of Tunisia between the concessions of Debbech, Cherouq and Jenein Centre. Production started in 1983 and currently about 1 300 MSCFD of associated gas is being flared. This figure is expected to grow in the near future.

ETAP is currently considering gathering the gas from the different production sites and transporting it to a nearby gas trunk-line. Carbon Limits has performed an initial techno-economic assessment of the proposed solution for the Laarich field.

Based on the information available, the project is technically feasible and is economic to implement for a range of gas price. These conclusions are aligned with the initial information received from ETAP. An increase on sizing of the planned pre-treatment facilities could yield even further economic returns. The final sizing of the pre-treatment and compression facilities will depend on the result of the drilling program and on the updated gas production forecast.
6. Estimate of capital investment required to stop flaring in the country

As part of this Study, a rough estimate has been made of the required capital expenditures (CAPEX) of the ambitious target of reaching zero routine flaring in Tunisia at all the existing fields. It is assumed that all routine flaring is eliminated, independent of the economic viability of the investment. It should be noted that the zero flaring initiative does not prescribe elimination of all routine flaring at existing sites but only "..seek to implement economically viable solutions to eliminate routine flaring from existing oil fields" (but with more stringent flare avoidance obligations for new oil fields). The analysis performed and the results are summarized below.

6.1 Analytical approach and assumptions

For the purpose of making the CAPEX estimates, flare sites are placed in a few broad categories as shown in Table 1. The most firm estimates are for the case studies which account for about 85 million USD. Number of fields, the location and flare levels for the other categories are estimated from data provided by NOAA. Table 1 shows the relative importance of each category:

<table>
<thead>
<tr>
<th>Category</th>
<th>Number of flaring sites</th>
<th>Volume of gas flared in 2014 (bcm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Very small sites (&lt;0.002 bcm/year)</td>
<td>13</td>
<td>0.003</td>
</tr>
<tr>
<td>Small flare sites (&lt;0.01 bcm/year)</td>
<td>13</td>
<td>0.057</td>
</tr>
<tr>
<td>Medium flare sites (&gt;0.01 bcm/year, offshore)</td>
<td>2</td>
<td>0.044</td>
</tr>
<tr>
<td>Medium flare sites (&gt;0.01 bcm/year, onshore in the vicinity of a gas infrastructure)</td>
<td>12</td>
<td>0.299</td>
</tr>
<tr>
<td>The three case studies (BBT, Chergui and Laarich) and Cercina</td>
<td>4</td>
<td>0.14\textsuperscript{34}</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>44</strong></td>
<td><strong>0.55</strong></td>
</tr>
</tbody>
</table>

\textsuperscript{30} http://www.ngdc.noaa.gov/eog/viirs/download_global_flare.html (data for 2014)
\textsuperscript{31} Source NOAA and Carbon Limits analysis
\textsuperscript{32} This figure is based on NOAA methodology and is associated to a large uncertainty range, please refer to noaa paper for the full methodology
\textsuperscript{33} Cercina, was not included in the case studies but capex estimates for a flare reduction investment has been obtained from ETAP
\textsuperscript{34} Current flaring based on satellite data, flaring is projected to increase in a number of these fields. The flaring estimated from satellite for these 4 sites is higher than the ETAP’s estimates.
Capital expenditures assumptions for the different investment categories (other than the “case study category”) are presented in the table below. There is substantial uncertainty associated with making generic estimates, as every site present some specific challenges and barriers to gas utilisation. As an example, the flare sites analysed as part of this study have capital requirements ranging from 2 to 40 Million USD/MMscfd capacity to fully eliminate routine flaring.

Table 2: Capital expenditures assumptions for the different investment categories

<table>
<thead>
<tr>
<th>Category</th>
<th>Low estimate (MMUSD/MMscfd)</th>
<th>High estimate (MM USD/MMscfd)</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Very small sites (&lt;0.002 bcm/year)</td>
<td>NA</td>
<td>NA</td>
<td>It is assumed that the very small flares site are operational flares (i.e. not routine flares)35</td>
</tr>
<tr>
<td>Small flare sites (&lt;0.01 bcm/year)</td>
<td>6</td>
<td>8</td>
<td>Assumes on-site power generation</td>
</tr>
<tr>
<td>Medium flare sites (&gt;0.01 bcm/year)</td>
<td>30</td>
<td>50</td>
<td>This figure is particularly uncertain. The two gas flares offshore are situated far from the coast (&gt;60 km) and are relatively small. The costs and the barriers for these two project may be significant.</td>
</tr>
<tr>
<td>Medium flare sites (&gt;0.01 bcm/year) in the vicinity of a gas infrastructure</td>
<td>2</td>
<td>5</td>
<td>Assumes tie-in to the nearest gas infrastructure (gas pipeline, gas processing plant)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Include tie in to the Nawara Project</td>
</tr>
</tbody>
</table>

6.2 Results

As shown in the figure below, it is estimated that elimination of flares existing in 2014 will have implied capital expenditures of 330 to 570 million USD.

35 It is important to notice that some operational flares have a flaring rate higher than 0.02bcm and that some very small flares may be routine flares. However this assumption is based on the data available.
A couple of conclusions can be highlighted from the analysis performed:

- The case studies (including Cercina) represent between 15 and 25% of the total CAPEX requirement.
- Tie-in to the existing and new gas infrastructure represents by far the largest abatement potential (about 0.3 bcm). The CAPEX estimate to eliminate gas flaring from this category ranges from 60 to 180 million USD (18 to 31% of the total CAPEX estimated).
- Offshore flares represent more than 40% of the CAPEX estimates even if their share of flaring is relatively low at 9%. This estimate should be used with caution given the important cost and technical challenges associated to small gas flaring projects offshore. In addition, a large part of this cost is associated to Ashtart field, which is a really mature field (production starts in 1974), which experience a number of operational challenges\textsuperscript{36}

Excluding the offshore gas flares, between about 170 and 270 million USD is required to eliminate routine gas flaring in Tunisia.

In addition to the considerable range in the cost estimated for different equipment etc two other caveats to the analysis should be mentioned:

- The costs of the Nawara project\textsuperscript{37} are not included. This project greatly improved the technical feasibility and economic attractiveness of the flare reduction projects in the south and explains why these projects have much lower costs per unit of captured gas compared to the offshore projects.
- The base year for the analysis is 2014 and some of the flaring recorded at this time may have been eliminated or in the process of project completion.

\textsuperscript{36} Information from ETAP
\textsuperscript{37} Project already developed and financed