1.0 Introduction

1.1 History of Shell in Libya

In the early 1940s Shell was the first and major petroleum products distributor in Libya. Its activities were concentrated in the main cities, the coastal strip and areas where British troops were located. At that period the quality of the products and services gave Shell an unmatched reputation at all levels.

The introduction of the new oil legislation ***No 25 / 1955*** gave new opportunities to the oil industry by offering new contracts to take up oil concessions for exploration and production, Shell was offered five concessions as per the following schedules:

Concession	**Zone**	**Date**
31	I	27/01/56
41	II	11/01/56
52	IV	15/12/56
70	I	08/04/57
114	II	16/04/66

Source: MENAS

These contracts reflected Shell's interest in investment in Libya which was, at that time, considered to be a new area of high potential and a major new source of oil. As a result, as many as forty oil companies from many parts of the world applied for these concessions which was a phenomenon not experienced in other oil-exporting countries.

In all, Shell managed to drill 46 exploration wells of which only four were commercially productive. Of these, three oil wells had an output of 1,950 b/d per day and the fourth well produced both crude and natural gas.

This modest scale of production failed to reflect the company's position in the international oil industry when compared with other companies operating in Libya during the period from 1956 till 1967:

Company	**number of wells drilled**	**producing wells**
Shell	46	4
Mobil	349	203
Esso	433	190
Amoseas	247	151
Oasis	667	407

Source: MENAS

Even though Shell took on a large number of concessions in Libya, which it retained for a long time, the end result was poor and disappointing.

A major step taken by Shell in 1966 when it purchased half of Amerada Hess's 1/3rd share of **Oasis Oil**, giving it a 1/6th share and an equity split as follows:

Shell	16.66 %
Amerada Hess	16.66 %
Marathon	33.33 %
Continental Oil	33.33 %

The new group was awarded the following concessions:

Concession No.	**Zone**	**Concession No.**	**Zone**

25	I	29	2
30	1	31	2
32	1	59	2
60	1	71	3
28	2	26	4

Source: MENAS

These contracts were different from the previous concessions offered to Shell when it was a sole operator. Oasis Oil explored and discovered oil and gas in three major concessions; 32, 59 and 71. Production reached its peak in 1970 around 946,065 b/d in which Shell‘s share topped 158,000 b/d.

Shell also entered into an agreement with the ***General Oil Corporation*** in 1968, but was not successful in discovering oil in the concessions that it was allocated. The terms of this contract had called for installation of an oil-mixing unit, which was not put in place.

Shell was also part of a 50:50 joint venture with Standard of New Jersey (Exxon); called Gewerkschaft Elwerath. Elwerath had a 50:50 interest in blocks with Wintershall. Wintershall bought out Eleweraths share in the mid 70s.

Nationalisation

Following the Libyan Revolution, it was decided in 1970 to exercise control over the country’s main resource - the oil industry, which was run and exploited by foreign oil companies. The initial steps taken by the Libyan Revolution had a direct effect on the foreign oil companies and included:

- Nationalisation of the distribution activities in respect of oil products and in July 1970 oil export to the *National Oil Corporation.*
- In May 1970, the new government implemented ***Rule 8*** to limit oil production to take account of technical and economic criteria, which led to a reduction in oil production from 3.3 to 2.2 million b/d in 1973. This action affected Shell’s share in oil production in the Oasis Group which in 1973 dropped from 950,000 b/d per day to 771,000 b/d so Shell’s share dropped from 158,000 b/d to 129,000 b/d.
- Publication of ***Law 66 in 1973*** nationalised the oil industry and limited foreign oil company shares in production to 49 % thereby investing the Libyan side with a share of 51%.

Shell Oil took a contrary stand to the Government decision by rejecting the nationalisation legislation, which forced the Libyans to issue a new law, ***Number 35/74***, to nationalise Shell Oil. The rest of the oil companies accepted the 51%/49% formula and thereby eventually safeguarded their presence and oil activities in Libya. Some of these companies went so far as to sign new agreements and new contracts, for example, **Esso**, Occidental Oil, Mobil Oil, **Agip Oil**, **Braspetro** and **Total**. Some companies entered into offshore exploration with 15% and 19% shares.

When in 1981 the American Government restricted American oil companies from operating in Libya and froze Libyan assets in the USA in 1986, these companies maintained their presence and rights in Libya and kept in formal contact and informal relations with Libya. Meanwhile, they prompted the American government to improve relations with Libya and to pave the way for their return to Libya for oil operations. This expansive approach towards an ultimate renewal of activities opened the way to the US oil companies following the recent improvement in US-Libyan bilateral diplomatic relations.

In the light of this development, the direct or indirect influences of these oil companies on the American Government to improve relations with Libya cannot be ignored and have not been without their impact on Libyan attitudes towards them. Shell's performance, in contrast, made it appear that it was diffident towards its role in Libya and unmindful of the importance of Libyan oil to the European market.

Shell's connection to its position in Libya was limited to a few contacts now and then which were not regarded seriously by its Libyan counterparts and gave no real indication that Shell was serious about its investment in Libya even after it returned there in 1980 when it was awarded two blocks (under *EPSA* terms of the period) in the ***Sirte*** and ***Ghadames*** basins. Here Shell drilled only two wells after which it withdraw from further exploitation of the blocks, a move that reflected a lack of interest in continuing its links with Libya.

In 1999, Shell was invited to join a new Exploration bidding round. However, because of the parlous state of the Libyan oil fields, there seemed to be a greater opportunity in IOR projects at the time and contact was sought to discuss material IOR opportunities with the Libyan Secretary of Energy.

As Shell did not have a presence in Libya at the time, an agreement was made with Veba oil (operating the giant Amal field on behalf of the NOC) to share the IOR approach. The Sarir/Messla fields in the Southern part of the Sirte Basin, operated by the National Agoco company, were selected as the best opportunity and a proposal was presented to the Libyan NOC for a joint IOR and resource inventory study.

The NOC rejected the Shell/Veba proposal in late 1999, but proposed to first engage on an IOR pilot study on a smaller scale. Shell/Veba subsequently selected Block 47 and – after signing an MoU with the NOC - embarked on a full study in 2000. This included detailed field development studies and was followed by the submission of a commercial proposal for Block 47 IOR in 2001. However, no agreement could be reached on a suitable baseline and – when it came to light that the NOC had proceeded by implementing the majority of the recommendations themselves – it was decided in 2002 to suspend the project.

In 2000, Shell also tabled their interest in a gas opportunity in the Sirte Basin – the Sirte Gas Project. This project comprised initially of the upstream development of existing gas discoveries in Block 6 and NC98 coupled with an evacuation route through the existing Marsa El Brega LNG plant. This plant would initially be re-juvenated to operate at acceptable standards and to extend the plant's life and subsequently upgraded to accommodate additional gas production.

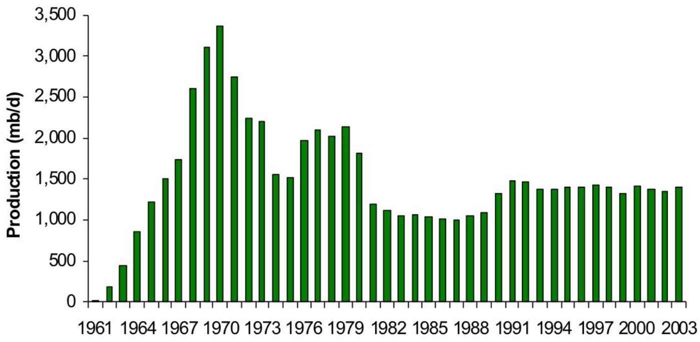
NC98 contained a large under-explored and un-developed gas-condensate accumulation, discovered by the Oasis Group. Due to the American interest and the possible political exposure to the Shell Group, it was decided to suspend the Shell interest in NC98 in 2002. At the end of 2003, NOC indicated their refusal to allow Shell involvement in the existing fields in Block 6.

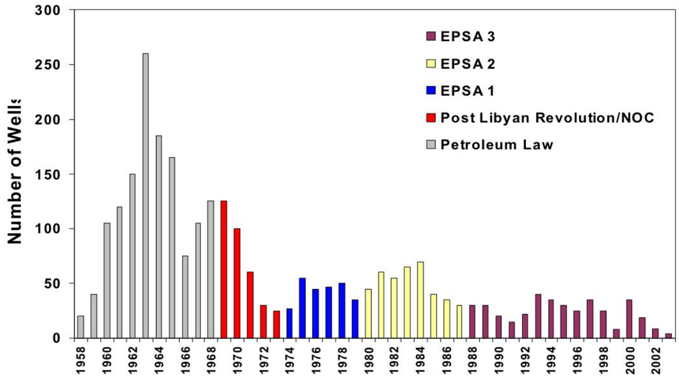
On NOC's request, Shell investigated the exploration potential of Block 6 and discovered several deep leads in late 2002. This triggered interest in the open Blocks to the North of Block 6 in 2003, which subsequently resulted in a significant exploration project, which is presently being discussed with the NOC as part of the Sirte Gas project in conjunction with the above mentioned LNG project.

To support the new-venture activities, Shell opened an office in Tripoli in late 2001 with Peter Osborne as the first Country Chairman. On the retirement from group service of Peter Osborne in 2004 he was replaced by Med Mahmoud the current CCh..

1.2 Past performance and future potential of Libya upstream

A combination of OPEC quota constraints, standstill agreements on sanctioned assets, and constrained exploration and exploration activity have resulted in Libyan oil production stagnating at 1.4-1.5 MMb/d over the past decade with Libya gas production averaging 90-100 mboe/d over the past decade (Figures 1a&b).



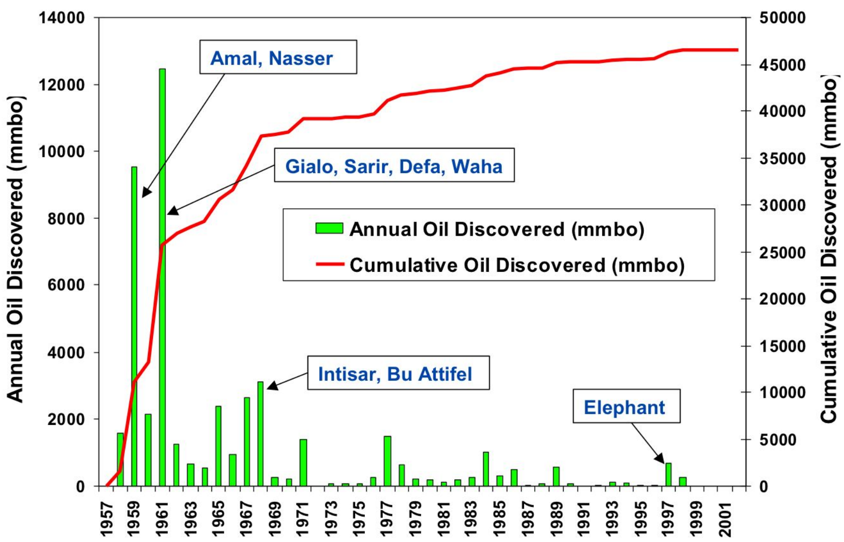


Source: PFC Energy

Figure 1a

Figure 1b

Drilling activity peaked in the mid-1960's, following a series of important discoveries in the Sirte basin. With the creation of the Libyan NOC, stiffening contract terms and US sanctions, drilling was limited in the mid-1980's to the present (Figure 2).

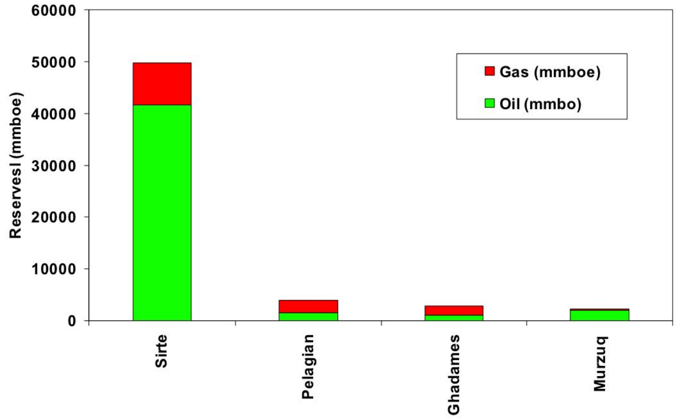


Source: PFC Energy

Figure 2

If the history of Libyan reserves additions is assessed it can be seen that there is a close correlation with the reduction in drilling activity, whereas some of this flattening of the cumulative oil curve can be attributed to normal creaming curve effects it is felt that Libya is relatively under explored and that this is not representative of the countries future potential.

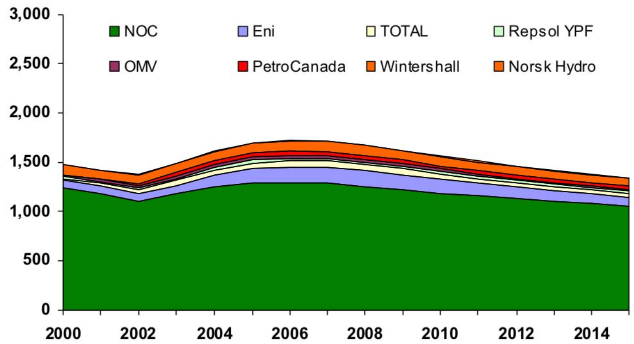
Reserves to date have been found in the following proportions by basin (Figure 3):

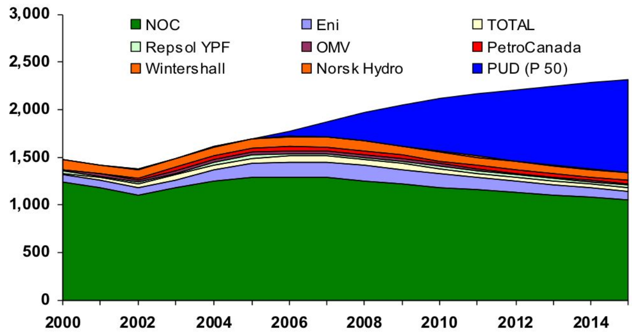


Source: PFC Energy

Figure 3

Based on existing sources Libyan production is expected to grow to around 1.7 MMb/d by 2006/7. The addition of proven undeveloped reserves (P50) is expected to increase production to around 2.4 MMb/d by 2015 (Figures 4&5).

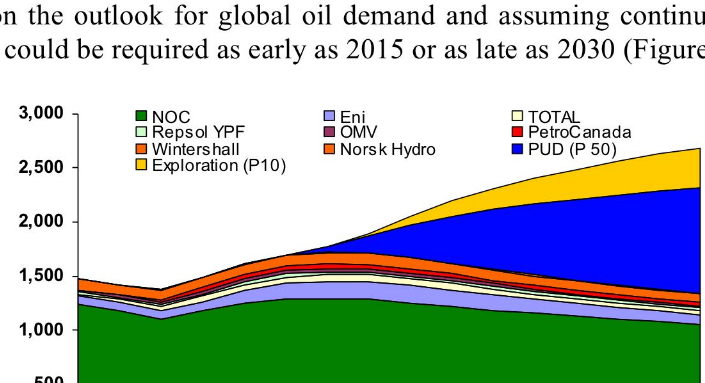




Source: PFC Energy

Figure 4 Figure 5

Based on exploration success and reserves additions performance of the last 20 years and expected exploration activity in the future, P50 exploration is expected to add little to the overall Libya profile. However the more optimistic P10 Exploration outlook could see larger and accelerating production from exploration activity to between 2.5 and 3 MMb/d moving into the next decade, with a commensurate impact on the Libya production profile. Depending on the outlook for global oil demand and assuming continued OPEC coherence, this capacity could be required as early as 2015 or as late as 2030 (Figure 6).



Source: PFC Energy
Figure 6

1.3 Opec constraints

OPEC quotas are restrictive. But in high demand periods, such as in 2004, this restriction is only nominal. For example, Libya is producing above its 1.445 MMb/d quota now, as are any other OPEC members with the capacity to do so. The quota restrictions will apply only in case of low demand or high non-OPEC growth – as a defensive measure to stem price slides.

Note also that all members are strongly averse to price slides, as this has a much larger impact on their export revenues than a small cutback in production.

The outlook in the short to medium term is for OPEC to proactively support prices by enforcing aggregate quota discipline. But unless demand falls drastically, the brunt of day – to- day management will be borne by core OPEC (the Saudis, in concert with Kuwait and the UAE). Although any production expansion from Iraq will have to be borne by OPEC, Iraqi capacity is expected to expand very slowly in the short-term, and the brunt of adjustment borne by core OPEC.

But in the event that global capacity falls short, or that demand is unexpectedly robust, OPEC has shown (in 2004) that it will expand production to dampen prices. Most forecasts suggest that oil demand will expand by between 1.5 to 2 mln b/d, while non-OPEC grows between 1 to 1.5 mln b/d. Although this does not leave much room for OPEC growth, it does not envision cutbacks. In the longer-term (beyond 2008-2009), non-OPEC growth is expected to weaken considerably, and oil demand is expected to be robust, thus easing the quota constraints on OPEC members.

It is also worth noting that the January production cuts by OPEC, in anticipation of further price slides in 2005Q1, shaved 5% off current production, rather than quotas (Figure 7). This substantially benefits the members that are producing above quota, including Algeria, Nigeria and Libya. By not using the existing quota system as a basis for cutbacks, the quota shares that Venezuela and Indonesia have been unable to use because of their capacity limitations are in effect going to the other members to varying degrees. Note though that this has not yet been formalised, and Venezuela is likely to oppose such a move.

Opec's New Production Benchmarks

**Includes Neutral Zone.*

(1,000 b/d)	**Output**	**Offered**	**New**	**Old**	**Change**
Country	**Nov.**	**Cuts**	**Jan. Norms**	**Nov. Quota**	**Vs. Quota**
S. Arabia*	9,650	500	9,150	8,776	+374
Iran	4,000	0	4,000	3,964	+36
Kuwait*	2,500	120	2,380	2,167	+213
UAE	2,475	120	2,355	2,356	-1
Qatar	815	40	775	700	+75
Venezuela	2,580	0	2,580	3,107	-527
Nigeria	2,433	120	2,313	2,234	+89
Indonesia	940	0	940	1,399	-459
Libya	1,600	80	1,520	1,445	+75
Algeria	1,300	20	1,280	862	+418
Opec 10	**28,293**	**1,000**	**27,293**	**27,000**	**+293**

Source: PXG
Figure 7

1.4 Libya/NOC short-term needs and long-term aspirations

Gaddafi has begun a long term plan for transferring power peacefully to his one of his sons, most likely SAQ. In order to achieve this he will have to bring prosperity to the Libyan population and may be one of the drivers for his about term in the late 1990's with respect to Libya's relationship with the international community and most specifically the US and UK. In order to achieve this and show the benefits of fuller integration into the world economy he will have to deliver greater revenues for spending on visible projects to improve peoples standard of living at the same time maintaining his families income stream.
Looking to the short term future, Libya will wish to close out any remaining EPSA III based deals as soon as possible so as to move all new contractual terms to the new EPSA IV ones. On the current EPSA IV round Libya can be expected to look to maximize the exploration commitment at the minimal cost to the government with the aspiration to deliver a future production scenario represented in figure X. This potential will give them a bigger role in OPEC and should allow them to put pressure on OPEC for a quota increase.
In addition to increased exploration, investment will be needed in the short to medium term in upgrading existing assets with new technology now available following the lifting of sanctions. Also dormant assets that have been identified but not yet developed are likely to receive impetus to be developed in order to replace production capacity once current production peaks in 2006/7.
To increase the probability that the plan can be delivered, increase the inflow of foreign capital and to increase the competitive environment so as to put pressure on the IOC take, new (old) players can be expected to gain access to Libyan opportunities. The return to active participation in Libya by the Oasis group is expected in early 2005 and other US companies that have highlighted Libya as a key target for NBD can be expected to bid aggressively in the EPSA IV round and for other business opportunities.
The further development of gas monetization routes/infrastructure will also be key to Libya revenue generation. The pipeline route to Europe is well controlled by ENI through their Greenstream project, however due to the small LNG plant at Brega, the LNG route is open to competition. Shell with its current EPSA III deal linked to a Brega plant upgrade is well placed to capitalize on this need. However, the Brega upgrade alone will not provide Libya with a real stake in the LNG business, a world scale plant will be necessary. Construction of the world scale plant will control the LNG monetization route and is likely to be hotly contested by lead players in the LNG industry.

3.0 Gas country strategy/activity and plans

At the high level, a gas country strategy is shaped by three simple factors: **gas volumes** (reflecting country current and future gas resources), **gas production costs** in the country (reflecting location, quality and other particular circumstances of those gas resources) and **gas utilization options** (reflecting fit and linkage with the other complimenting elements of the full gas value chain both within and outside the country)
The gas strategy that any given player will adopt in a particular country will be driven by his particular position (current or anticipated) along the three factors mentioned above.

The starting point for a formulation of a gas strategy for Shell in Libya, is thus a review of the country (and Shell's) gas volumes, gas production costs and gas utilization options. These will be covered under sections 4.1, 4.2 and 4.3.
The particular circumstances of Shell in Libya, both current and aspired, will then shape-up the concrete, doable and most suitable gas strategy for the country. These will be covered under sections 4.4. and 4.5.
And since even the best formulated strategy has no value, unless flawlessly implemented, section 4.6 addresses some of the key execution pillars for the developed gas strategy and section 4.7 provides the basis for a concrete action plan.

3.1 Gas Supply/Demand in the country

3.1.1 Gas Supply

For the purpose of assessing the supply and demand situation in Libya, the country could be split in two areas: The West (around Tripoli), with Melithah as its regional gas hub and the East, with Berga as its main gas hub (see map in Appendix 1)
In the West existing gas resources are tied-up for the West Libya Gas Project (WLGP) which supplies the export pipeline to Italy (Greenstream) and a small export to Tunisia; however, no significant exploration potential is seen for further export beyond the maximum capacity of the Greenstream pipeline (currently 8 bcm/a but could easily increase to11 bcm/a).
In the East a production of some 10 to 15 bcm/a is forecasted from projects, which are based on discovered volumes. Additional exploration potential in the East has been identified in the order of 18 bcm (risked volumes associated with a number of potential or identified leads).
Associated gas is a potential additional source but will be relatively limited compared to development and exploration projects. It is forecasted that this will not exceed the level of 3 bcm/a and is rather costly to gather due to the high number of locations.

3.1.2 Domestic gas demand

Domestic gas demand could be split in three separate areas:

- **Power:** There are 7 existing thermal plants with an installed capacity of 4600 MW. The current fuel mix is 60% Gas Oil (Diesel) and 40% Fuel Oil (LSFO). Only one plant is converted to take gas but plans are in hand for conversion of remaining plants. When all existing plants are converted to gas some 360 mmscf/d of gas will be required. Also there are aggressive plans by Gecol (national power concern) to add another 5000 MW capacity by 2010, however it is difficult to see all this materializing in the mentioned timeframe.
- **Petrochemical:** Consists mainly of the production of methanol, ammonia and urea from the Brega and Ras Lanuf complexes, with the bulk of the production destined for export. Some 180 mmscf/d of gas is currently being used as feedstock.
- **Industry:** Consists mainly of steel factories using some 120 mmscf/d and cement factories using some 75 mmscf/d.

The power sector, with the conversion to gas of existing power plants and the installation of new gas-fired power plants is and will remain the major driver behind domestic gas demand growth. A scenario approach linked to the level of the country economic and political normalization has been adopted to forecast the gas demand in the power sector, as follows:

- Base Case (steady normalization): assumes that conversion to gas of existing power plants will be delayed by a modest 1-2 years compared to the aggressive plan setout by Gecol. Gas demand for power is assumed to grow at a solid level of 6% per annum (p.a.) until 2015 and at 4% p.a. thereafter (in line with the traditional S-curve growth curve)
- High Case (accelerated normalization): assumes that conversion to gas of existing power plants will be as per Gecol's plan. Gas demand for power is assumed to grow at a high level of 8% p.a. until 2015 and at 4% p.a. thereafter.
- Low Case (stalled normalization): assumes that conversion to gas of existing power plants will be delayed by some 3-4 years compared to Gecol's plan. Gas demand for power is assumed to grow at a modest level of 2.5% p.a. (similar to the growth rate witnessed during the last 2 decades of sanctions)

The total domestic gas demand for the three power scenarios described above and assuming limited growth in the other sectors is depicted in figure 1:

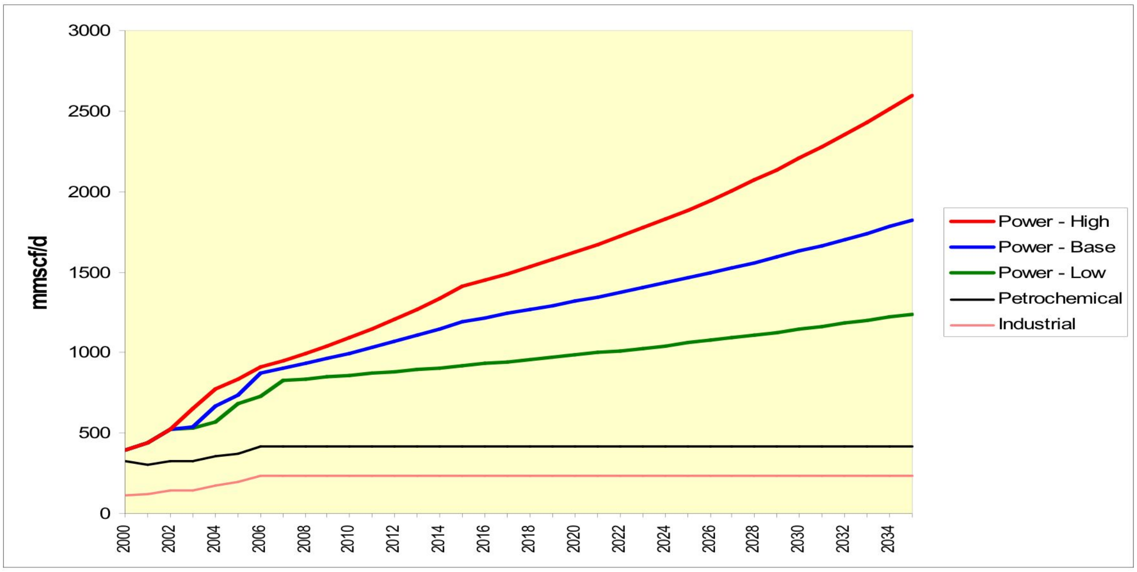


Figure 1

3.1.3 Gas Supply and Demand Balance

A countrywide gas supply and demand assessment was undertaken in 2002 and subsequently updated in 2003. Supply associated with existing fields was derived from data transmitted to us by NOC. Exploration potential was put at 30 Tcf which is in the medium range of the volumes explorers believe are yet to be discovered. Concerning the demand side we used the domestic forecasts as per the scenario-approach described above. For export we reflected both the committed volumes (e.g. Greenstream volumes) as well as potential export through (for example) LNG. The country supply and demand balance over the next 30 years is depicted in the following graph (assuming the Base case power demand scenario).

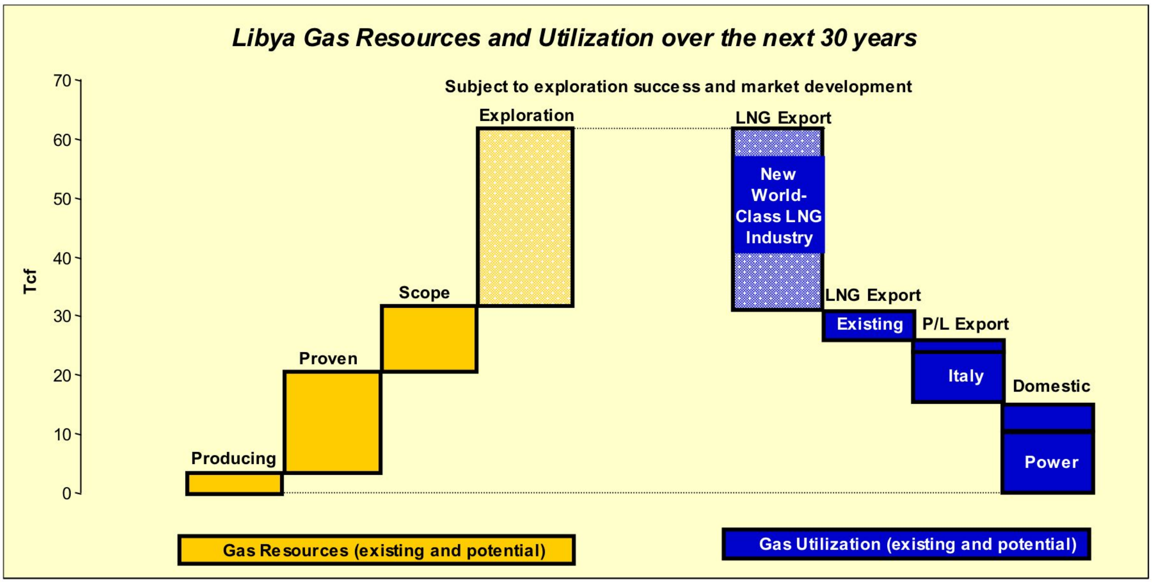


Figure 2

As illustrated in figure 2, the existing gas resources in the West area of the country are tied-up with the WLGP project and no substantial additional resources are expected. But even if additional resources are found in the Western part of the country, those would better serve the relatively higher domestic demand in that part of the country (around Tripoli) and decrease the costly east-to-west gas inflow. Any spare gas beyond the local needs could also supply the expanded Greenstream pipeline.

A focus on the Eastern part of the country where Shell EPSA3 acreage is located and where Shell's future acreage will most likely be (consistent with our exploration strategy of focusing on the Sirte basin) is needed. This is depicted in figure 3, which also restricts the exploration potential to the Shell EPSA 3 acreage:

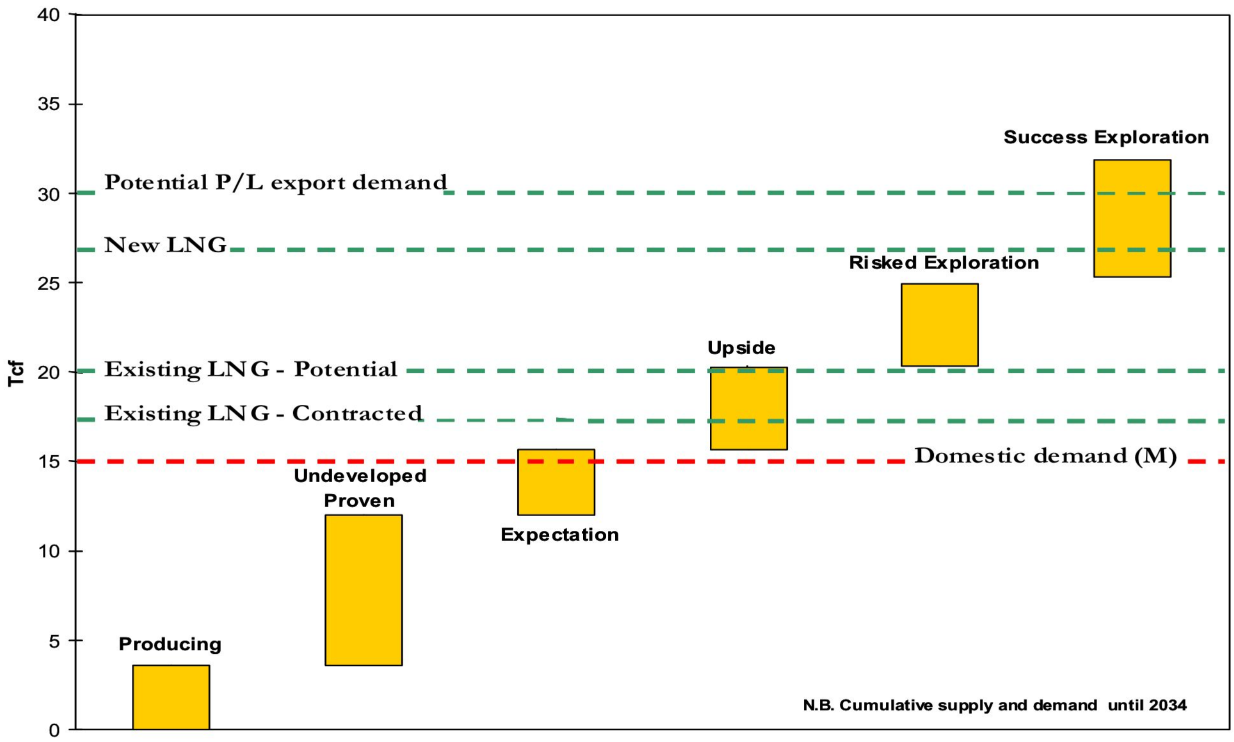


Figure 3

The key conclusions from the above two graphs are:

- Known gas resources (producing, undeveloped and scope) are either committed for export or will be required for the long-term domestic gas demand. However the ***timing*** of the domestic demand and the ***level of dedicated reserves*** set-aside by the country for the domestic market (we assumed that reserves equivalent to 30 years domestic demand will be required) are the two unknowns that will determine if opportunities for gas utilization outside the domestic market exist or not. For example if only 20 years of domestic demand are set-aside, then some 6 Tcf of gas reserves could be freed-up for export.
- New gas resources (either from exploration or enhanced production) will create (and at the same time will require) new export opportunities.

3.2 Gas utilization options and merits

Focus will be maintained on the Eastern part of the country (in terms of resources) for the reasons stated above. Simply put the question this section addresses is "what is the best utilization option for a gas molecule arriving at the Brega gas hub?" A total of 8 realistic options have been identified and are depicted in figure 4:

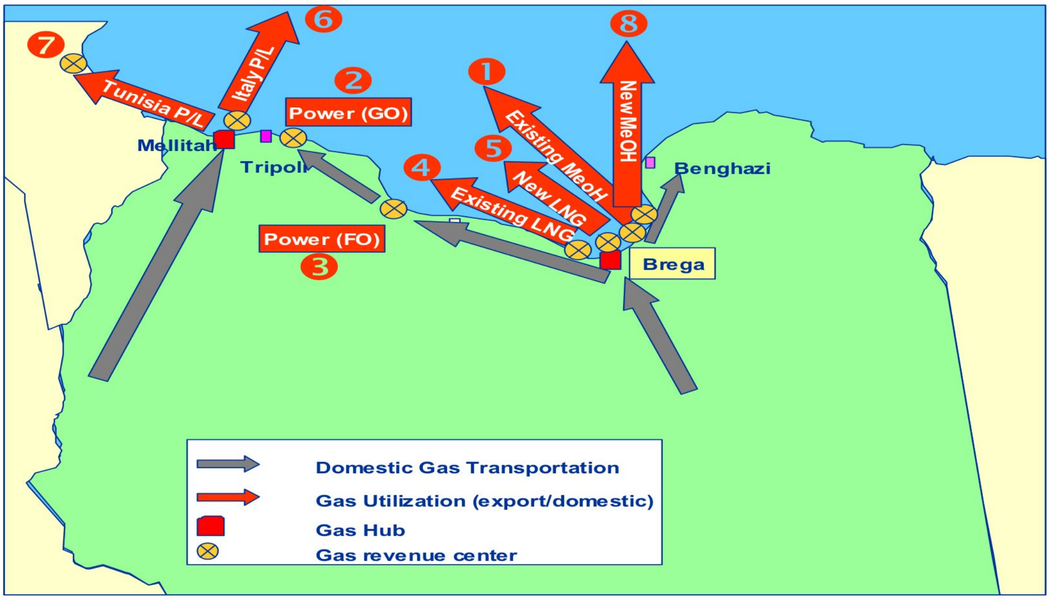


Figure 4

For the 8 identified options we have estimated for each their associated market netback value (i.e. the fair market value of the transformed gas molecule minus all processing costs) and ranked them accordingly. The results are depicted in figure 5, which also includes a first indication of a realistic volume size associated with each option:

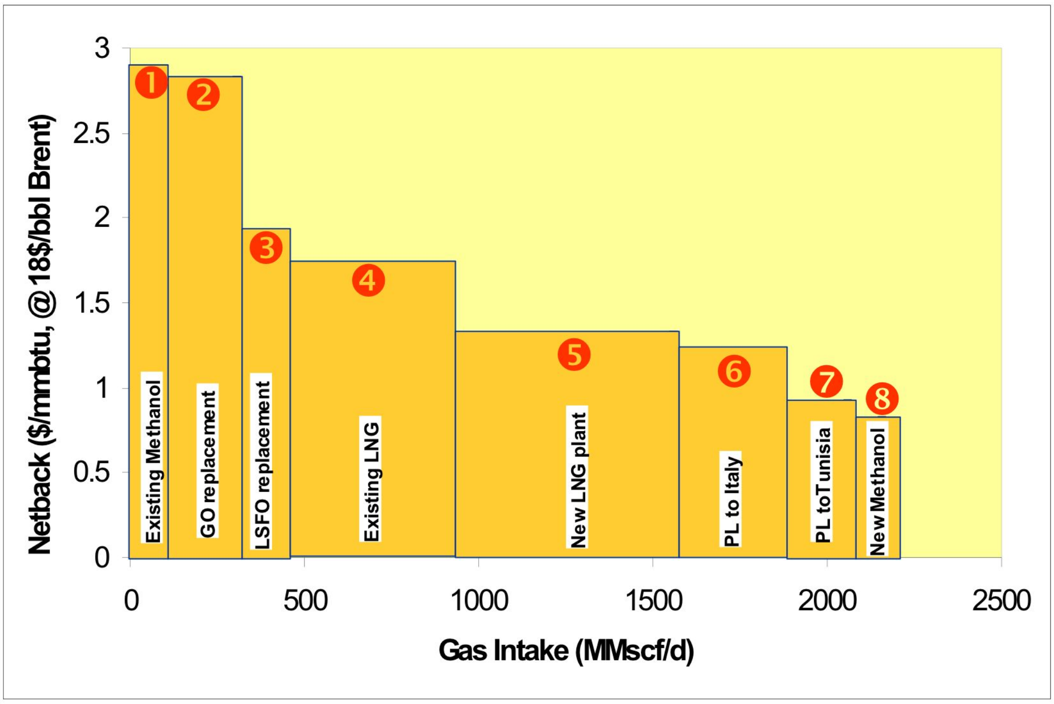


Figure 5

From an economic point of view and given the above, gas resources in the Brega hub should be used in the following order:

1. Supplying existing gas-transforming industries which are capital intensive (sunken costs) but associated with high value products (Methanol)
2. Replacing liquid fuels (Diesel and Fuel-Oil) in existing power plants and feeding new (gas-driven) power plants
3. Supplying existing LNG plant (lowest export outlet in the country) to maintain and increase LNG exports
4. Supplying new LNG plants in the Brega hub to expand LNG exports
5. Filling up capacity of the existing (expanded) pipeline to Italy
6. Supplying other regional pipelines (e.g. pipeline to Tunisia)

3.3 Gas export options and opportunities

3.3.1 LNG and link to Shell's Atlantic Basin LNG Strategy & Portfolio

<u>Attractiveness of Libyan LNG</u>

LNG supply from Libya is very competitive due to relative proximity to both Europe and the United States, and high liquid content. This is clearly evident from, for example, in figure 6 which compares the total unit LNG supply cost to Southern Europe (Spain) of some 12 existing and potential LNG projects worldwide. Similar graphs for the North West European and East Coast US markets are displayed in Appendix 2, figures 1 & 2.

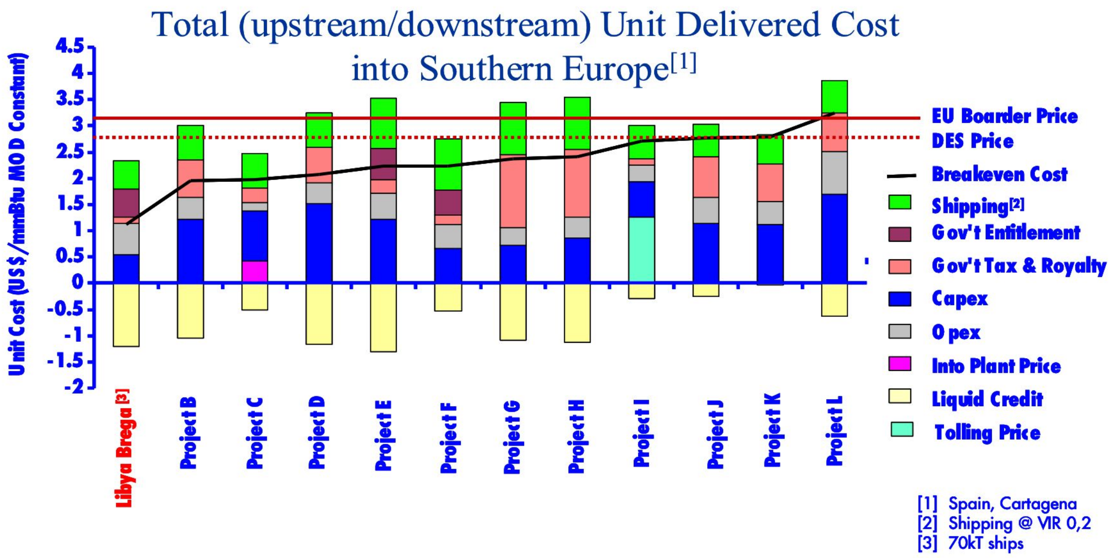


Figure 6

Material LNG developments with destination flexibility therefore would rank in the top of Shell's Global LNG supply portfolio. At present, Libya Brega ranks in Tier 2 of the global LNG portfolio, but this position reflects the current modest dimension of the project, and does not take into account future expansion potential.

Importance of Libyan LNG for Atlantic Basin

Strategically, Libya is seen as a key contributor to meeting the 2012 Atlantic Basin equity LNG supply aspiration of 13.7 million tons per annum (mtpa) split between Europe (5.7 mtpa) and North America East Cost (NA/EC, 8 mtpa).

For Europe, out of the 5.7 mtpa aspiration, some 3.6 mtpa will be supplied by existing projects and the rest (some 2.1 mtpa) will need new supply projects. Graph 3 of Attachment 2 shows that on a risked basis, Shell is 0.6 mtpa short of meeting its 2012 aspiration for Europe. To meet this aspiration, success in PLNG T1 and Qatar LNG T1 or Libya Brega LNG is required. Brega in itself, due to its possibility for early startup, can serve to build Spanish and Italian markets before Middle East projects come on stream around 2011-2012. The aspiration for Europe is to supply Spain with 2.2 Mtpa and Italy or France with 2.8. Depending on the supply source Shell share, an additional 0.3 Mtpa may be necessary.

For the NA/EC market, out of the 8 mtpa aspiration, only 2.1 mtpa is supplied by existing projects and the remainder 5.9 mtpa will require new projects. Graph 4 of Attachment 2 shows that, on a risked basis, Shell is short by 3.2 Mtpa in meeting its 2012 North American aspiration. To meet this aspiration, maturation in Nigeria and success in Libya Greenfield, or Venezuela, or Cameroon, is required. Libya Greenfield is currently not included in the LNG portfolio, but would improve this situation and provide a counterbalance to further West-African supply growth.

Destination of Libyan LNG

Current expectations around the LNG portfolio dynamics and aspiration, dictate that LNG from Libya Brega LNG would target Spain and/or Italy between startup and 2010/11. After that, and with exploration success justifying further expansion with a Greenfield projects, Libyan LNG should target the Unites States East Coast and Gulf coast. To realize this, the Marsa El Brega harbour, at the right time, will have to be expanded to cater to large ships (145K M3 type) suitable to cross the Atlantic.

3.3.2 Pipeline & Link to Shell European Gas Strategy & Portfolio

The North Africa to Europe gas strategy work executed jointly by EP / GP / SEE in 4Q04 concluded that Libyan pipeline export to Italy would remain limited to the new GreenStream pipeline. This was due to the high GreenStream construction costs, and the strategic value of GreenStream control to ENI who were deemed unlikely to cede debottlenecked volumes to Shell at a competitive price. This last assumption should nonetheless be tested commercially, particularly as the PoS would be higher if wrapped in a wider Shell deal with ENI.

Alternative pipeline export options, such as via Tunisia or Egypt were also discussed but judged unlikely; Tunisia on a materiality basis as the relatively low volumes that could be swapped for Tunisian options on Algerian gas to Italy are small, and Egypt because Libya was deemed more likely to desire autonomy and hence create it's own export facility. However, Shell should explore the Tunisian swap link due to the possibility of early gas into Europe, again more likely if included in a wider deal with ENI.

Appendix 3 provides for a more detailed summary and supporting graphs of the North Africa analysis.

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3.4 Brega LNG Project

3.4.1 Description and scope

Shell has negotiated as part of the EPSA3 exploration deal an option for the upgrade of the existing LNG plant in Marsa al Brega. This option is captured under Exhibit G of the Exploration and Production Sharing Agreement (EPSA) that sets out the key principles and some of the terms and conditions relating to the maturation and, upon subsequent FID, execution of the LNG Project. The LNG Project consists of the rejuvenation and debottlenecking of the existing LNG plant and will be under the control and supervision of a joint Shell/NOC Steering Committee (2 representatives each, unanimous voting) to be established within 1 month from the EPSA3 contract becoming effective. The LNG plant will be operated by the current operator SOC (an NOC affiliate) and will be supported and advised by Shell (Global Solution).

3.4.2 Gas supply requirements and timing

The execution of the scope of the LNG project will be phased such as to match gas availability: the rejuvenation phase (to extend the safe and reliable operations of the LNG plant by another 20 years) will be executed immediately after FID and will be underpinned by gas supply from NOC (some 200 mmscf/d of feedgas resulting in some1.2 mtpa of LNG production). The debottlenecking phase (to increase LNG plant operational capacity to some 3 mtpa equivalent to some 500 mmscf/d of feedgas) is conditional on proving sufficient gas resources in the Contract Area and the start of related commercial gas production dedicated to the LNG plant.

3.4.3 Equity versus non-equity gas

The Brega LNG project will be initially underpinned by third-party gas from NOC. However NOC gas supply obligation will cease at the end of the exploration period (minimum 7 years) and alternative gas supplies (preferably linked to exploration successes) will need to be in place. Failing that Shell involvement in the Brega plant will also cease.

What the Brega LNG project does in essence is to use some third-party gas (as an anchor) to create surplus capacity that will later pull our own gas, if available, or any other gas, if the supply could be structured such as to make the integrated play attractive to us. The position created through the Brega LNG project will be valuable for our own equity gas when available, and in the absence thereof, as a good basis for negotiating access to gas reserves controlled by third parties.

3.5 Beyond Brega

At the strategic level LNG should be the main (and possibly the only) gas export option Shell should focus on. The rationale behind this choice is as follows:

- ENI with its Greestream project has created a significant "barrier for entry" for any player wishing to consider an export gas pipeline. It will be very difficult for Shell to differentiate itself or to compete with ENI with a "pipeline deal".
- Future gas resources are most likely to be located in the Eastern area thus better served by the Brega hub and the LNG export route.
- Undeniably Shell has a track record and a competitive advantage in LNG which could be used as a basis for an attractive value proposition to NOC and other partners.
- The Brega LNG project will form the basis and provide synergies for other LNG expansion projects.

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3.5.1 New LNG Plant/Trains

Libya enjoys a strategic geographical position and although current gas resources are relatively modest when compared to other gas exporting countries, these are set to grow significantly with the recent (gas) exploration dash. Yet the country is lagging behind in terms of LNG development, and while the Brega plant was one of the first to be commissioned worldwide, the current LNG production from Libya is small (+/- 0.8 mpta) and even after the implementation of the Brega LNG project the expected LNG production (~ 3 mtpa) would remain modest by regional or global standards.

Clearly potential for development of a world class LNG industry in Libya is real and Libya will need reliable partners to make this happen. The key questions are what role can Shell play in this, how to leverage the Berga position and what would make Shell the partner of choice for Libya?

The Libya + project is being developed with the objective of developing a compelling proposal, using the Brega project as a springboard, allowing Shell to gain a material commanding position for LNG development in Libya ahead of the competition. Libya + will include a proposal for the development of a world class LNG plant in Libya, together with the development of a continuous chain to supply the US and other key markets, possibly offering Libyan participation along the entire chain including shipping and specific regas-terminal(s). An Opportunity Framing Workshop will be held the last week in January 2005 to confirm the proposed modules on gas supply availability, the proposed liquefaction plant, commercial structure, downstream value proposition, recruitment and sustainable development.

The intention is to present the Libya + proposal to the Libyans in Q1 2005 in the footsteps of the ratification of the integrated EPSA3/Brega LNG contract. At the strategic level, this serves to demonstrate Shell long-term commitment to and aspirations for the country. Tactically this will ensure that Shell is contended with for any major LNG development in the country beyond Brega and will buy us valuable time vis-à-vis some of our competitors (ENI, Oasis, Occidental) who are (or soon will be) in a much better position to realistically progress a world-class LNG scheme in the near future thanks to the gas reserves they already control.

3.5.2 New Export pipeline

As mentioned earlier ENI with its Greestream project has established a controlling position over any "export pipeline deal" in the country. We believe that a direct competition with ENI is not an option and barring corporate deals, we believe that there isn't much room for partnering either.
Export pipeline should not be part of our offerings to NOC or other partners.

3.5.3 Is there potential for GtL?

Gas to Liquid (GtL) is the right solution for huge, stranded and cheap gas resources. While Libyan gas is definitely cheap, it is certainly not stranded thanks to its proximity to major markets. Moreover the size of the current reserves is modest and while this is likely to increase, we don't believe that in the short or medium terms this will increase to a level that would justify a world-class GtL scheme. GtL technology and expertise (particularly after progress on Qatar GtL) should however be retained in our offerings to NOC and partners and used as a "marketing" tool.

3.6 Key Execution Pillars

3.6.1 CVP

From our past experience with engaging with NOC and other Libyan stakeholders we came to realize that our offerings is only as good as what the other party needs or expects. After a series of trial and error we believe that the core of a value proposition to Libya in relation to gas (and oil) projects should include the following (ranked by importance):

- Addition of (gas) reserves that would result in increase of production.
- Provision of "complete solutions" that span the entire design, planning and implementation phases. A strong and hands-on involvement by the IOC is expected during the implementation phase.
- Offerings should be based on the provision of new solutions that NOC has no capability or experience to implement alone and that would result in concrete and measurable bottom line benefits.
- Financial support, while not in principle a strict requirement, allows NOC (and other politicians) to deploy their resources in more "visible" areas.

3.6.2 Engagement and Involvement

While the oil and gas expertise base is relatively thin (NOC experts for instance are overstretched) the decision-making is widely spread out in Libya. This combination makes it really hard to develop then get approval for any new proposal.

Simplicity should really be the key shaping force behind the structuring of any new proposal complemented by a continuous and wide engagement.

In the past we have failed partly because of a "selective" engagement targeting what we perceived as the right "decision-makers", "experts" or simply as our "friends". The reality in Libya is that because of the continuous reshuffling in the country and the "apparent" flat-decision making, those "labels" are likely to continuously change. Our "friends" could become our "foes" and vice-versa and the "decision-makers" of today are no longer the next day.

3.6.3 Partnering

The ultimate objective behind partnering is to create synergies and to render deals more doable and robust.

For the Brega LNG project, players who could add value or create synergies are those with relatively small gas resources that could be pooled to supply the LNG plant or those who have existing dealings and/or relationships relevant for the project. Examples of potential gas suppliers include Repsol and Wintershall. Gas Natural could be another good candidate for partnering since it has been the sole buyer of Libyan LNG and currently enjoys excellent relationships with the marketing department of NOC.

For projects beyond Brega (Libya +, etc…) the only area where Shell is weak along the entire LNG value chain is access to gas resources. Exploration when successful will remedy this weakness but only in the medium/long term. Other players with material gas resources could, if they are fast enough, frustrate our LNG development efforts by taking a first-mover advantage. The current 3 material holders of gas in the country are ENI, Waha (Oasis) and Zuitena (Occidental). ENI gas is mainly tied-up with Greenstream. Oasis (and possibly also

Occidental) after their (near) come-back, wants to go it alone with LNG development. Arguably the consortium (Marathon/ConocoPhilipps/Amerada Hess) has the required expertise and (US) market access, rendering partnering with them an impossibility.
One option is to use acquisition to force our way in the reserves of Oasis or Occidental. However given the above, asset acquisition will be very difficult. For Oasis for example, the Waha concession could become the jewel in their portfolio. Corporate deals are therefore the only alternative and this route needs to be considered in the wider regional or global context.

3.7 Conclusions and Recommendations

Libya's gas resources are set to grow beyond the needs of its local market thus creating (and at the same time requiring) new export opportunities. The new gas resources are expected to come predominantly from the Sirte basin and will be better served by the LNG export route from the Brega hub. Yet the country's current policy of reserving the majority of its uncommitted proven reserves to the long-term domestic requirements, does not allow it to expand its LNG export capabilities beyond the existing Brega plant in a timeframe to allow it to rival other supplies from the region. New gas export projects will hinge on the country domestic gas policies and the capability of foreign partners to solve the gas supply issue. Players who control (undeveloped) gas reserves or those who realistically could increase existing production (through innovative solutions) will most likely be the partners of choice for NOC.

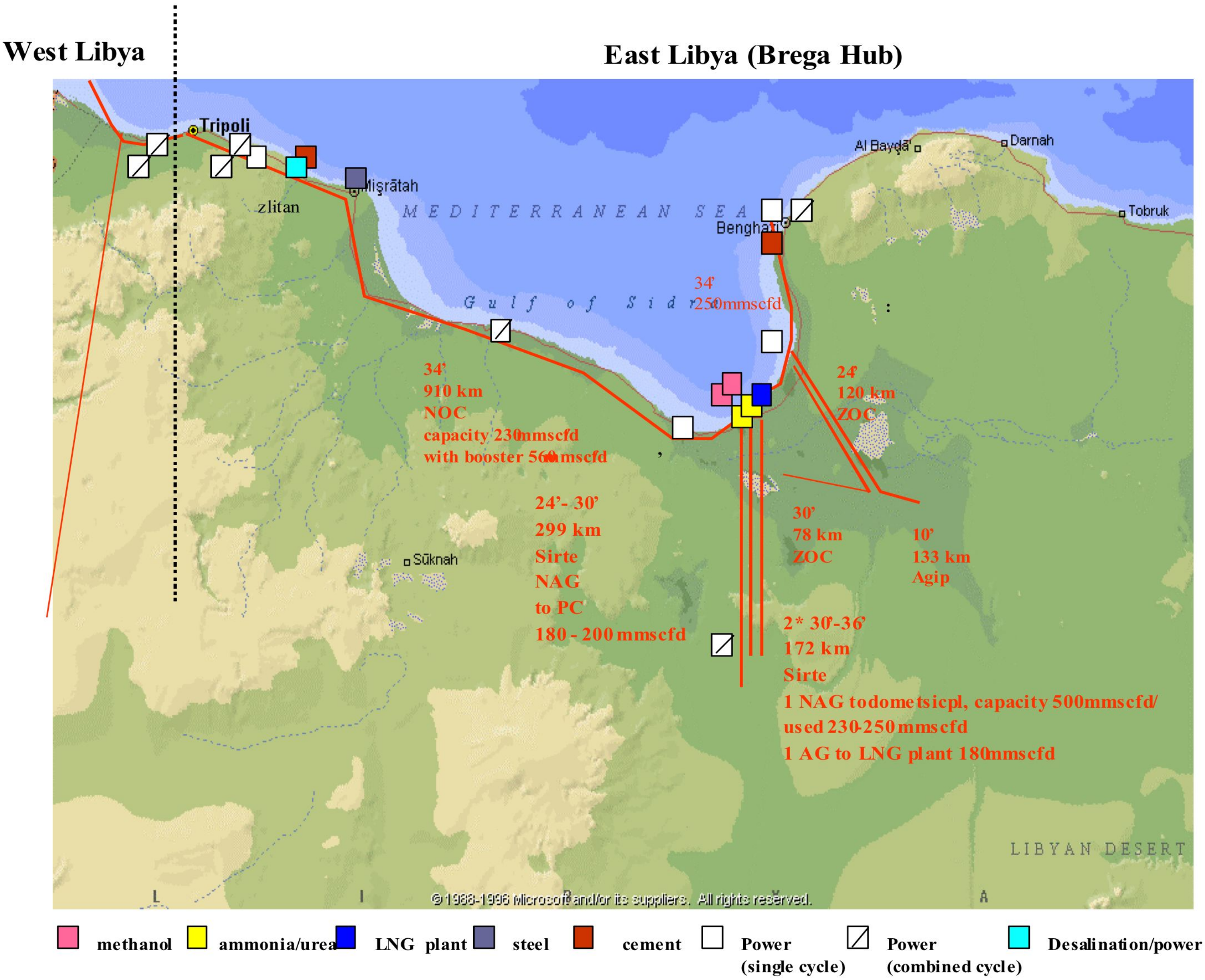
For **Shell** (Gas&Power) LNG should be the name of the game in Libya and our long-term goal should be to have a significant share of a material LNG business in the country.
The Brega LNG project provides an excellent start for the above aspiration but more importantly illustrates the approach that could be taken to be successful while managing the uncertainty around timing of gas availability: the use of any available (even third-party) gas to anchor an (expandable) LNG export scheme which in turn shall pull further equity and other parties gas. This virtuous circle of inter-feeding gas supply and demand carries significant risks (e.g. mismatches between gas supply and demand) and could only be sustained through flawless delivery and the proper management/acceptance of those risks.

Looking forward our attention should be focused on the following:

- Maturation of the Brega LNG project to FID and the successful implementation of its first phase as an absolute priority.
- The identification of additional gas resources (through partnering, acquisitions, deployment of new technologies or exploration) as an enabler for the second phase of the Brega LNG project
- Duplication of the above two steps at a larger scale through the offering of bigger liquefaction trains and securing larger gas resources via a combination of acquisitions/partnering and increased exploration. This is in essence the scope of the Libya + initiative.

Appendix 1

Libya Map: West and East supply & demand areas



Appendix 2

Figure 1: LNG supply competitiveness into North West Europe market

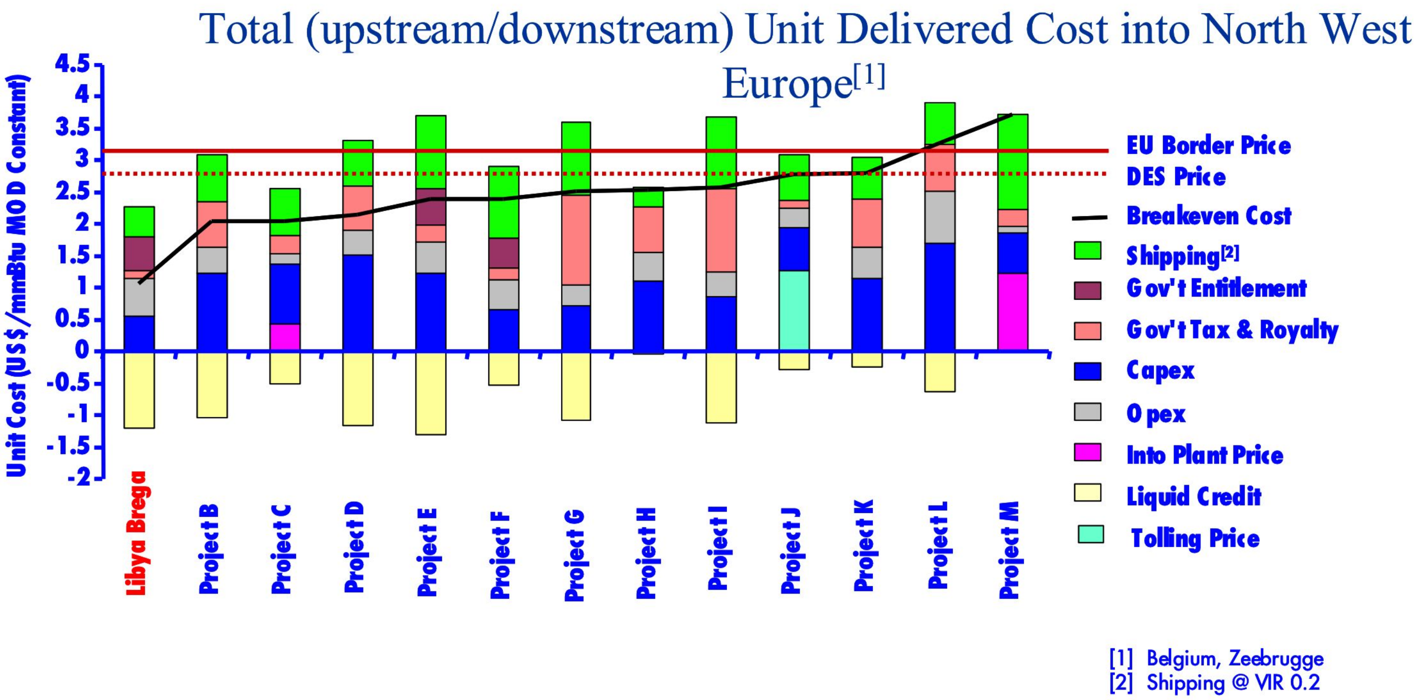


Figure 2: LNG supply competitiveness into North America East Coast market

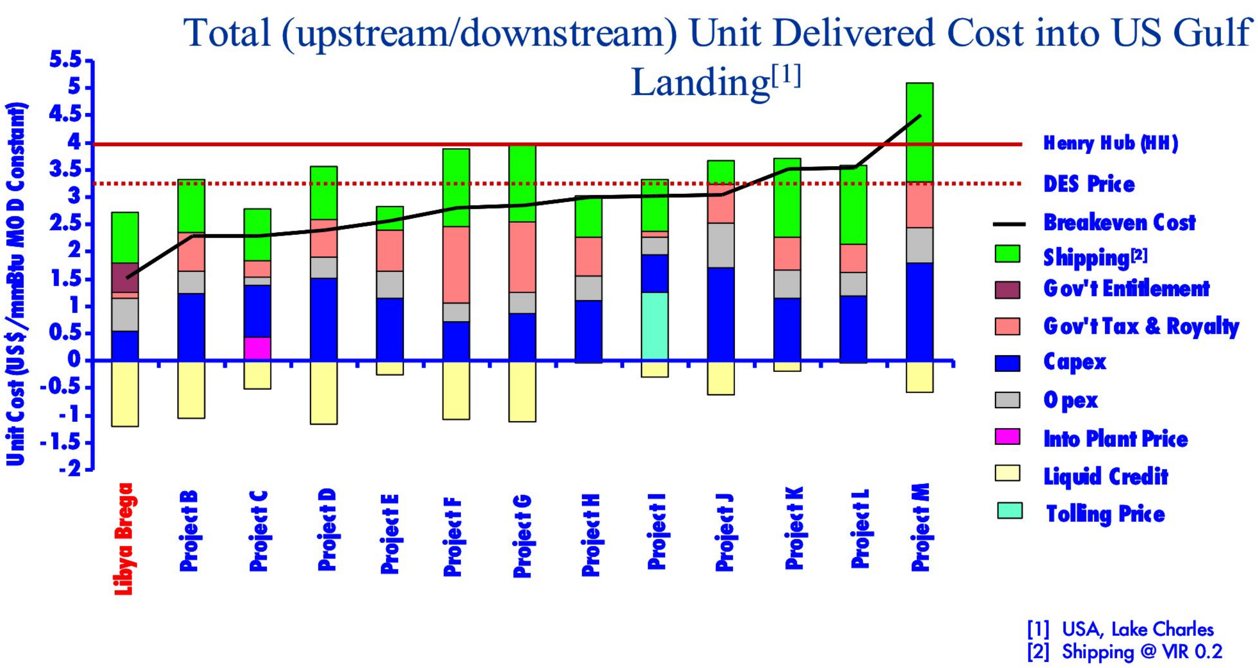


Figure 3: Shell European LNG Portfolio – Market Aspirations (2012) versus Supply positions

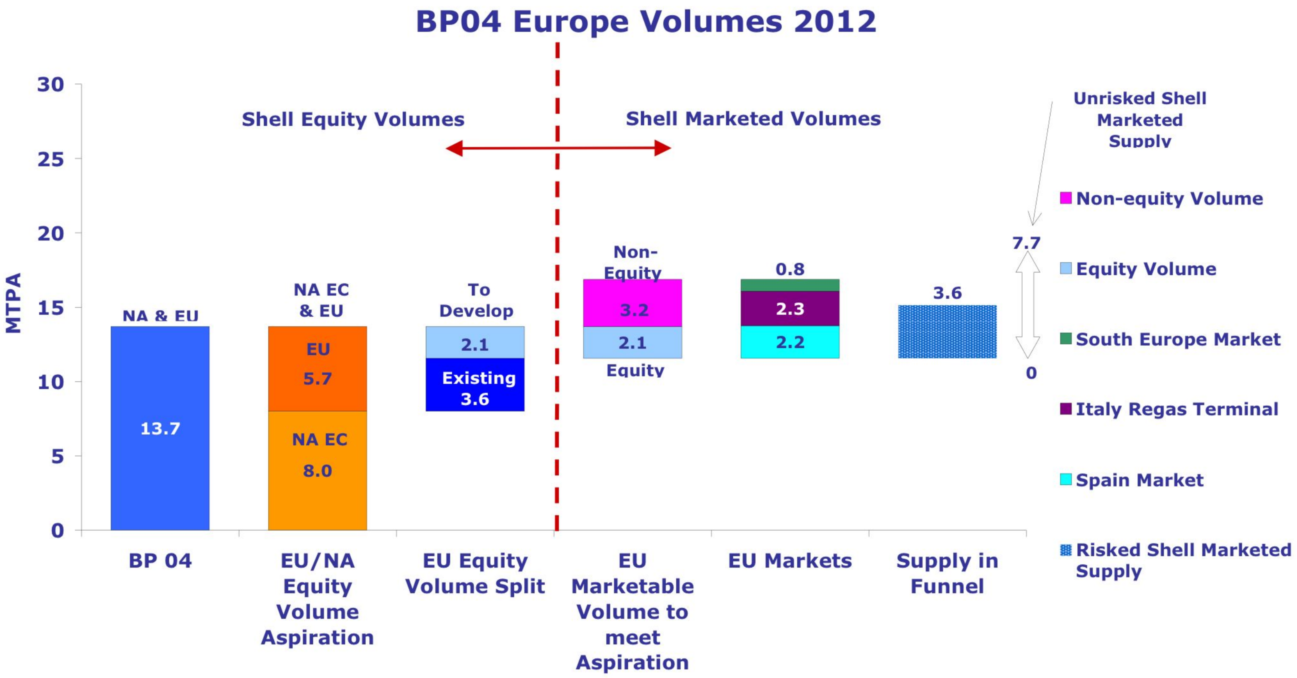
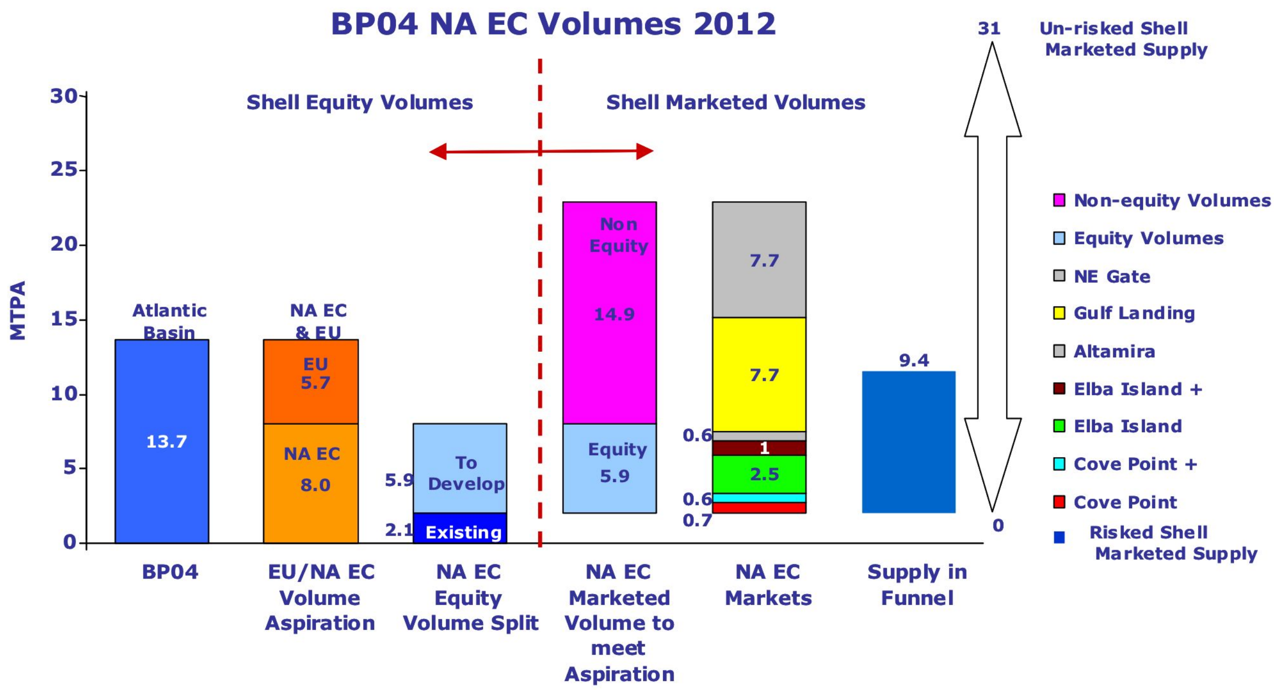


Figure 4: Shell North America (East Coast) LNG Portfolio – Market Aspirations (2012) versus Supply positions



Attachment 3

This is an extract from the North Africa to Europe Gas Strategy work executed jointly by EP / GP / SEE in 4Q04. Charts are screenshots of the Arena / NetSim model prepared for that analysis.

NB: The NetSim modelling incorporates a series of detailed assumptions on production profiles, UTCs, and export contracts. Reference should be made to the full report (see Orchestra).

Libya will continue to export gas from its Brega facility and the new GreenStream pipeline to Italy. It was assumed that additional LNG liquefaction capacity would be built. Based on NetSim's least-cost optimization, it can be seen that Libyan gas will be competitive into Southern Europe for the foreseeable future.

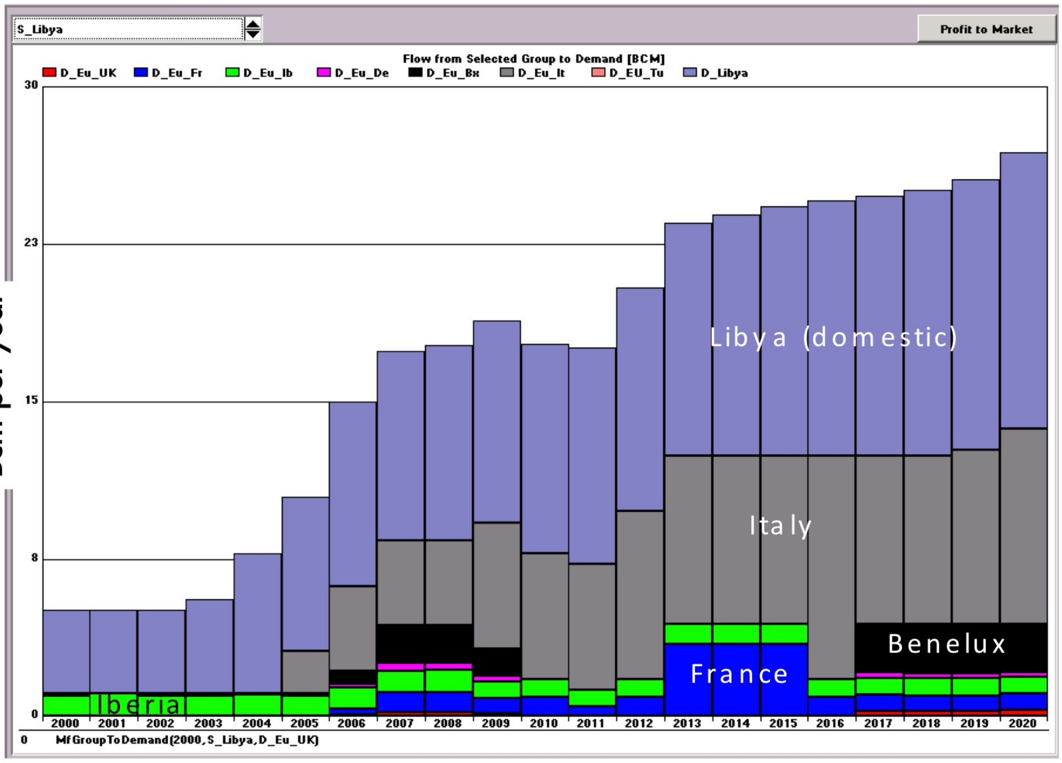


Figure 1: Forecast Libyan gas export by year

Comparing UDCs reveals that LNG from a Brega upgrade is competitive against most other supply sources, while both a new LNG liquefaction plant and the new GreenStream pipelines are more marginal in their competitiveness. For this reason, it is felt unlikely (based on current assumptions) that a new pipeline will be built between Libya and Italy. Instead, depending on discovered volumes, a new LNG liquefaction facility is considered more likely due to the greater destination flexibility it offers.

NB: Charts below exclude government take.

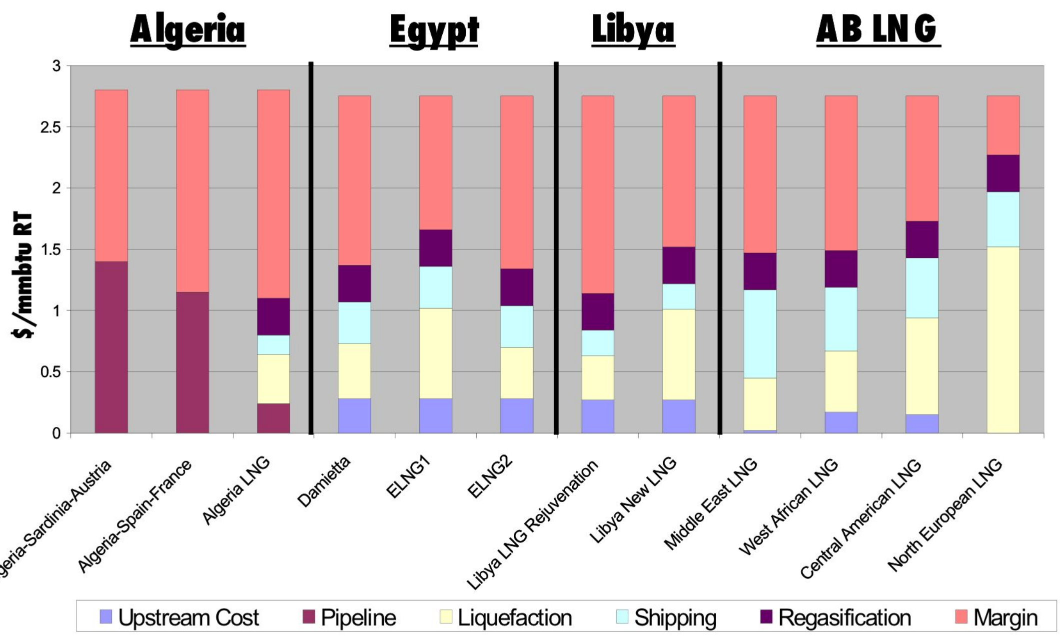


Figure 2: Comparison of gas margin delivered to France (2010)

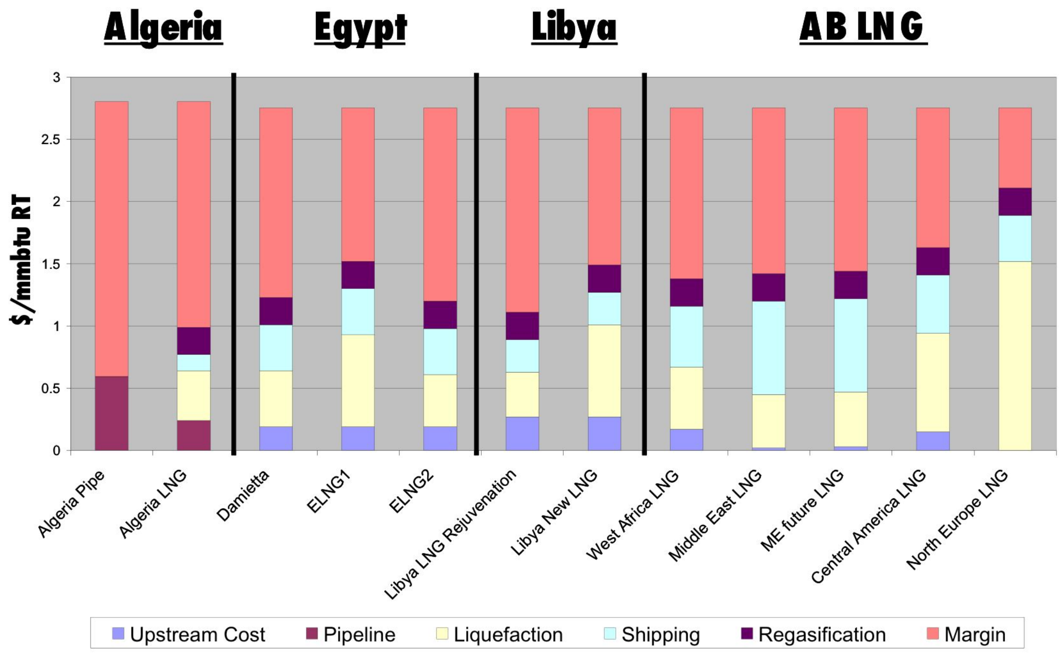


Figure 3: Comparison of gas margin delivered to Iberia (2010)

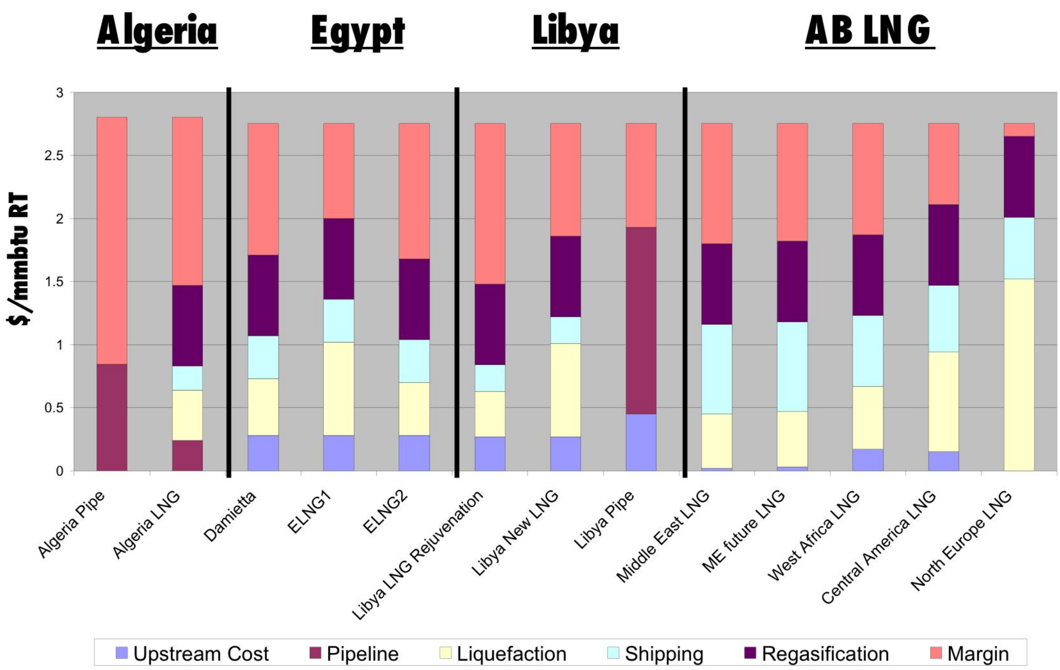


Figure 4: Comparison of gas margin delivered to Italy (2010)

Competitiveness of Libyan Supply

The export options of East Libyan gas from exploration and development activities are either via pipeline to (Southern) Europe or via LNG with the additional option to reach also the North American market.
The upstream Unit Technical Cost (UTC) at field fence of East Libyan supply is between 0.20 and 0.60 $/MMBTU, averaging at some 0.40 $/MMBTU. The UTC of the future fields from exploration cannot be known precisely at this point of time, but is expected to be on average at the same level of 0.40 $/MMBTU.
Compared to the Greenstream project the gas from the East has to carry the additional pipeline cost going onshore from the East to the West. These additional costs are around 0.40 $/MMBTU.

Pipeline to Italy and markets beyond Italy

The total pipeline supply cost of East Libyan gas into the demand node of Italy are in average about 2.20 $/MMBTU (0.40+0.40+1.40). From the supply-curve generated through the Arena analysis we found that the pipeline option is in the middle between the cheaper Algerian and the more expensive Yamal supply. It is more expensive than the averaged AB LNG supply into Italy by 0.1 $/MMBTU. Nevertheless it displays still a significant margin.

LNG against Pipeline

For the greenfield LNG developments a UTC of 1.8 $/MMBTU has been estimated (excluding liquid credits and excluding government take, similar to other LNG pricing approach for Europe & Egypt). As such the Libyan LNG is more competitive than the pipeline into Italy in average by some 0.20 $/MMBTU (vs. medium cost gas supply sources in East Libya, see details in supply cost curve for Italy).

The existing Brega plant after refurbishment and upgrade possesses the lowest UTC and is by far the most competitive source of supply; however, it should be kept in mind that it has limited capacity and flexibility (some 4 bcm capacity, and limited port size)

Libyan LNG against other AB LNG

Libyan Greenfield LNG is more competitive than the average AB LNG supply (which comprises MedRim supply, West African Supply & some ME supply) into the Mediterranean by some 0.15-0.20 $/MMBTU. Timing however remains a key success factor in capturing market positions ahead of competition.

Other considerations

The main competition for Libyan supply into Southern Europe besides other LNG is pipeline gas from Algeria. With current assumptions Algerian pipeline is more competitive due to the more favorable location i.e. the shorter distance. In addition it is more attractive due to the larger base of proven and producing gas reserves in Algeria. In the current model Algeria wins over Libyan supply by pipeline. Although in such a case Libyan gas would have positive margins in Italy, the market build up will not support two new pipelines from North Africa to Italy, especially in a Prism world. A pipeline from Libya could only be successful if it takes advantage from being the first mover. In such a case not the cheapest supply will win but the first, thereby cutting off the economic viability of the latecomer. A detailed analysis of the timing of a potential Algerian pipeline and the motivation and support of the Algerian stakeholders for such a pipeline will need to be further considered; however, it should be kept in mind that further exploration in Libya is required to support additional exports.

The development of East Libyan reserves looks more attractive via LNG than via pipeline firstly due to location factors and secondly due to higher flexibility with respect to potential markets. Libyan LNG looks rather competitive within the total of Atlantic Basin LNG supplies

4.0 Brownfield oil/gas development Strategy

Redevelopment of brownfields may involve the application of IOR and EOR techniques. IOR options include the water flooding and the installation of artificial lift (gas lift or ESPs). Screening for IOR options was not undertaken in this present study for two reasons:

- There is insufficient information in the public domain data sources to quantify the need or benefits from IOR options
- Shell does not have a differentiated value proposition for IOR

EOR options have been assessed against the recovery expected in a fully developed water flood (injection or aquifer influx) as predicted by the screening assessment. If an EOR strategy in Libya gains access to reservoirs, there would be additional benefits to Shell from any IOR activities, which would need to be put in place as part of an integrated field redevelopment.

4.1 EOR Screening

During 2004 the greater Middle East region was screened for IOR/EOR technical potential in two phases. Countries included in this study were Libya, Iran, Iraq, Syria, Kuwait, the Neutral Zone, Saudi Arabia, Bahrain, Qatar, UAE, Yemen, Egypt and Turkey.

The selected countries contained approximately 1700 oil and gas fields. In phase I these fields were progressively screened to select a subset of fields (geographically and geologically representative of the region) for detailed study of their IOR/EOR potential. Ultimately 42 fields covering 66 reservoirs were studied in greater detail. These studies showed there to be considerable IOR/EOR potential in the Middle East Region.

From the greater ME EOR study it was concluded that Libya showed one of the highest potentials for IOR/EOR development along with Iran (see figure 1), when potential is assessed against accessibility. The study also showed that due to the general maturity and size of existing assets within Libya, the Sirte region should be the focus of any further assessment of EOR potential. Other basins such as the Ghadames and the Murzuk should be ignored.

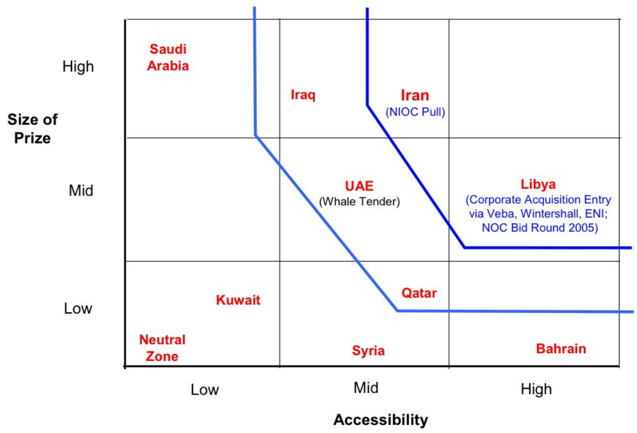


Figure 1

A second phase of study was undertaken, concentrating on high-ranking countries with a view to generating potential ranked target opportunities. All 276 fields in the Sirte basin were ranked based on a combination of weighted criteria (Operator, STOIIP, STOIIP/reserves, potential IOR/EOR prize, water injection maturity and remaining proven and probable reserves). These weighted criteria were supplemented by a series of screens (e.g. removal of all fields whose STOIIP was less than 100MMstb) in order to reach a more realistic group of fields for study.

The highest-ranking 28 fields (see **appendix 1**) were shortlisted for further more detailed consideration of the potential for their reservoirs to be successfully developed through the use of EOR techniques. EOR performance indicators were studied on a selection of these fields with final field selection ensuring that a representative geological and geographic selection of fields was studied **(appendix 2)**. An indication of likely field performance in non-studied reservoirs and fields can be gained by comparison to studied fields.

Screening Results

Ultimately a total of 25 reservoirs from 20 fields were studied with the performance indicators module of the Maestro tool. These reservoirs contain some 38.3 Bstb, which represents some 29% of the total Sirte Basin STOIIP (131.15 Bstb). These reservoirs were selected to ensure that a representative geological and geographical range was captured that could be extrapolated across the basin as a whole.

Results of screening are summarised in **appendix 3**, which shows that there is an EOR potential in the studied fields of some 3.1 Bstb. The greatest potential in the Sirte Basin is for WAG techniques with a potential gain of 2.6 Bstb oil from the studied fields.

In addition to the Performance indicators work on selected reservoirs a high level screen of all 409 reservoirs in the Sirte Basin was undertaken to assess their potential for thermal and polymer techniques. This screening using tempertature, depth and viscosity as input parameters shows that there is limited potential for EOR using polymers, although high salinities make this technique less attractive and restrict the polymer to xanthan. No thermal opportunities were identified.

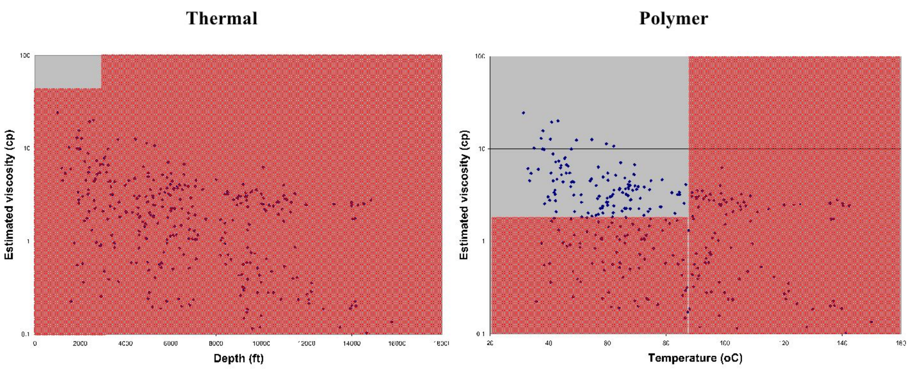


Figure 2

From the screening study carried out it is clear that there are two criteria key to dictating an implementation strategy:

- EOR gas supply
- Access to the fields

These will be dealt with in the next sections of this paper.

4.2 EOR gas requirements

Due to the large dependence on gas injection based EOR recovery techniques in Libya it would be prudent to consider the potential gas sources available to deliver this additional recovery. If all fields studied in Phases I and II are considered, then it can be seen (see **appendix 4**) that 3.7 Tscf of EHG gas and 92 mln tonnes of NGLs are required to deliver around 2.6 Bstb of oil through the use of EHG WAG techniques. If CO_2 WAG techniques are used then 7.0 Tscf of CO_2 is required to deliver 2.6 Bstb of oil.

If these figures are extrapolated across the whole Sirte Basin then the potential gain from EHG WAG schemes can be approximated as 9.0 Bstb, with a net requirement of 12.7 Tscf EHG and 310 mln tonnes NGL. CO_2 WAG techniques could potentially deliver 8.9 Bstb of oil with a net requirement for 24.0 Tscf CO_2.

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4.2.1 Gas Sources

Hydrocarbon Gas

In the Sirte basin the total recoverable hydrocarbon gas is 47 TCF in 189 fields. Recoverable gas with volumes in excess of 250 Bscf amounts to 41 TCF within 26 fields. Of this 41 Tscf 14 Tscf is held in gas and gas condensate fields of which 10 TCF is in the Attahadi and 2 TCF in the Hateiba fields. The rest is found as associated gas. Available data indicates that production to date accounts for some 17.5 Tscf of the recoverable gas. Of the remaining 29.5 Tscf gas some 21.5 Tscf is controlled by state oil companies (principally Sirte Oil Co with 13.7 Tscf).

Unlike Iran there is not expected to be a large excess of gas available for long-term re-injection as part of EOR schemes. It is expected that only small volumes of gas will be used for injection and that Libya will use large volumes for conversion into LNG or for pipeline export so as to monetize the available gas sooner. Current plans for the Sirte Basin (190303 gas masterplan) suggest a total gas supply of 15.7 TCF up to 2035 (12.4 TCF from existing fields, 1.6 TCF from flares gathering and 1.7 TCF from new developments). Planned capacity is for 1600 MMScf/d leading to a total gas requirement of 19 TCF up to 2035. An apparent shortfall of 3.3 TCF is expected to come from exploration (figure 3).

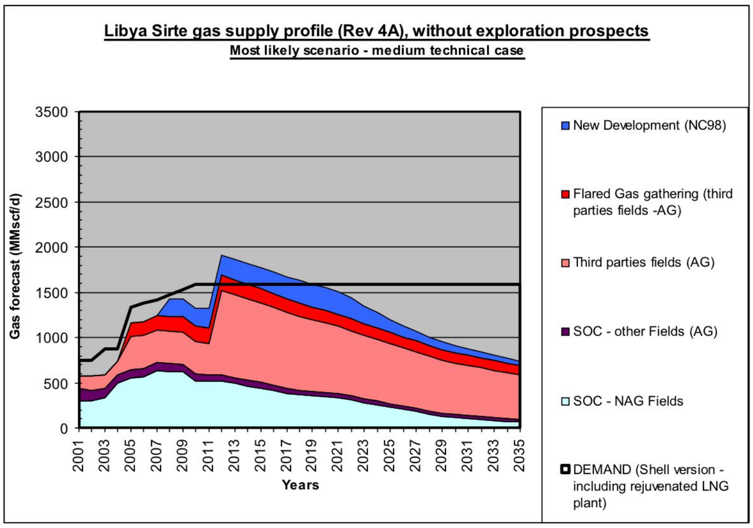

Figure 3

The above considerations could seriously limit Libyan potential for gas injection based EOR unless an alternative gas can be used.

An opportunity may exist within the Sirte Basin to develop a gas-gathering infrastructure, particularly if there is a lower internal market price for gases. However, given the current belief that Libya desires to export its gas it is likely that there will only be sufficient gas to develop a relatively small number of small to medium sized fields.

CO_2 Gas
A survey of CO_2 sources both within Libya and in neighbouring countries such as Tunisia., Algeria and Egypt has shown that CO_2 is most abundant in the Pelagian basin in the Libyan offshore area.

In the Sirte Basin, the currently known significant sources of CO_2 are the Attahadi and Hateiba fields. Attahadi contains between 2-8 TCF of gas with around a 12% CO2 content potentially yielding between 240 to 1 TCF of CO_2. The Hateiba field contains 2 TCF of gas of which approximately 11% is CO_2. Available data suggests that almost half of the Hateiba reserves have been produced to date, suggesting up to 100 Bscf of CO_2 could be extracted for injection in a similar manner to the BP operation at In Sallah in Algeria. The relatively small amounts of CO_2 that we are currently aware of suggest that Sirte CO2 will only be useable for a limited CO_2 WAG EOR program.

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The Pelagian Basin contains a number of large CO_2 (and N_2) rich fields which could be used for EOR schemes. In particular the undeveloped ENI field NC041-D-002 field (figure 4) contains an estimated 16 TCF of CO_2 and 4 TCF of HC gas. The Sirte Basin fields are 600 to 1200km from this field.

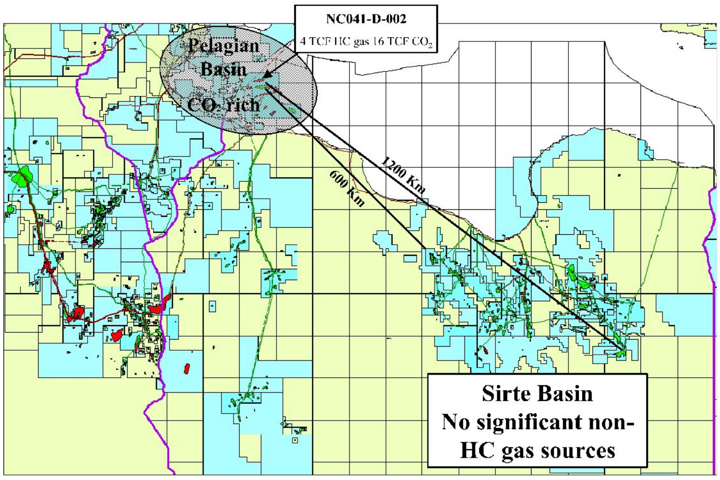


Figure 4

CO2 injection Rate	Cumulative CO2 required	Incremental Recovery	STOIIP Target	CO2 CAPEX ($/Mscf) distance from CO2 resource (km)			CO2 CAPEX ($/stb incremetal oil) distance from CO2 resource (km)		
MMscf/d	Tcf	Bstb	Bstb	600	1000	1400	600	1000	1400
100	0.9	0.34	4.2	0.67	1.12	1.57	1.82	3.04	4.25
500	4.6	1.7	21.1	0.35	0.59	0.83	0.96	1.60	2.23
1000	9.1	3.4	42.2	0.27	0.45	0.63	0.73	1.21	1.69

Table 1 CO_2 WAG incremental volumes, target STOIIP and indicative CO_2 CAPEX costs for different supply scenarios.

The use of this supply source for one or two small to medium sized EOR projects could not be justified. This would likely only be feasible if developed as part of an EOR master plan for Libya with the NOC.

In the longer term it may be possible to use a Pelagian basin facility as a hub for CO_2 collection and processing with CO_2 supply to Tunisia and Algeria (both closer than Sirte).

A possibility to very significantly add value to this CO_2 EOR strategy may be provided by a new technology that Shell is developing, "C3-sep" for separation of CO_2 and H_2S from contaminated gas. This was originally conceived as a significantly more cost effective way to clean contaminated gas prior to reinjection of contaminants for disposal. The technology is currently being matured, with an estimate for a single stage 250MMscf/d unit of around $10mln (two stages required for NC041-D-002). This technology provides an opportunity to significantly improve the economics of the Pelagian basin sourced CO_2 EOR by:

- Separating hydrocarbon gas for export
- Giving a higher purity CO_2 stream with lower MMPs and therefore better EOR performance

It should be noted that the amount of hydrocarbon gas produced through separation, if CO_2 EOR were applied to all the studied fields so as to produce 2.6 Bstb would be 2.3 Tscf with an additional 0.7 Tscf produced as associated gas from the fields themselves.

In a 1000 MMscf/d CO_2 supply world for a gas price of $2/Mscf the CO_2 CAPEX cost is around zero ($/Mscf) if sales revenue from the 2.3 Tscf hydrocarbon gas is taken into account.

The technology therefore could provide a linkage between EOR and LNG strategies on a country basis, with Shell proprietary technology as the enabler.

A key concern is that at present Shell does not have any assets in Libya, and is therefore negotiating from a position of weakness. The “C3-sep” technology is a Shell proprietary product (patent applied for) that could allow Shell a technological advantage at a very significant cost saving.

In addition some other technology angles exist:

- CO_2 separation from nitrogen is expected to be more efficient.
- Flue gas/industrial gas sources might be separated at lower cost (needs to be investigated), which could change the carbon tax incentives required for Kyoto compliance.

4.3 Access Strategy for priority EOR fields

Previous Involvement

Any access strategy must take into account our previous failed attempt at creating a unique value proposition for the EOR development of a field in block 47 proposed to NOC. In 1999/2000 an EOR study was commissioned which highlighted the Sarir Messla field as the highest priority. Engagement with the Libyans showed that it was too politically sensitive for them to allow a foreign IOC to enter. Following the study the fifth rank field was chosen in Block 47 and an MOU for an IOR project on Libya Block 47 was signed between Shell, Veba and NOC on 3rd October 2001. Access to data was granted and showed that five times less hydrocarbons were in place than shown by Woodmac data.

This presented Shell with a political problem as we had willingly selected the block. Two options were available; leave or spend USD 10 mln on a field development study. It was decided to spend the money. The agreement with the Libyans was terminated because of an inability to agree on a baseline. The Shell proposals proved not to be technologically unique enough and it was possible for the Libyans to adopt many of the recommendations made themselves.

One of the learnings from this is that we must understand the technical development requirements of the field well in advance and that we need to create a unique enough value proposition that it proves infeasible for the NOC to implement the concept without us.

4.3.1 Mid size fields

The Libyan government is unlikely, at this stage, to allow us access to the major fields that form the core of any national oil company portfolio and therefore a high level filter was applied to the Sirte Basin fields that focused our efforts on fields larger than 100 MMstb field STOIIP but smaller than 2000 MMstb STOIIP. It is proposed to develop a number of opportunities in parallel with the expectation that only one or two will actually reach maturity.

These middle sized fields (Table 2) could be used as a proving ground for the EOR technology and entry point to the basin whilst also providing a cash stream from production of existing reserves by conventional and IOR techniques (improved field management, waterflood, artificial lift etc.). It is stressed that the EOR incremental volumes should be considered in conjunction with additional reserves gain by IOR, which should precede the application of EOR. In many fields the additional production from IOR may be equivalent to that from the EOR gain.

Operator	Rank	Field	STOIIP (MMstb)	Best EOR Increment (MMstb)*	Comment
AGOCO	1st	Sarir (065-L)	1774	140	May be considered a ‘crown jewel’
SOCO/Veba	2nd	Lehib-Dor Marada	375	30	May not be material enough
AGOCO	3rd	Sarir North (065-C)	658	50	Good fit
SOCO	4th	Jebel	750	60	Good fit with EPX entry strategy as south of Nasser field and close to Brega plant. Expect LHG Crestal or WAG potential
SOCO	5th	Raguba	1875	150	May be considered a ‘crown jewel’. LHG Crestal or WAG potential
Veba	6th	Ghani Zenab	850	70	Good fit
Wintershall	7th	Nakhla	1000	80	Good fit
Veba	8^{th}	Ora	500	40	Fragmented and little data
Wintershall	9th	As Sarah	1000	80	Incomplete layering data
Zuetina (Occidental)	10^{th}	Sabah	482	40	

Table 2 Prospective mid-sized fields. (*Incremental EOR volumes are based on an average incremental recovery of 8% of STOIIP for studied Sirte Basin fields and are rounded to the nearest 10)

AGOCO and SOCO Controlled Fields
Develop an EOR master plan in partnership with the Libyan government. If managed carefully this could represent a project of such scale and significance to Libya that few other IOCs could match. Partnering with another IOC that has significant CO_2 injection technology experience (e.g. Occidental) should be considered as it would strengthen the value proposition and make it more unique due to the technical experience that could be leveraged.

We should target participation in the Sarir, Jebel or Raguba fields as compensation for our design and financing of the EOR master plan and as opportunities to prove our technology/capability.

The Atahadi gas field (SOCO) could be a useful CO_2 source and access to this field for CO2 recovery could form part of the early EOR masterplan proposal to develop a medium sized field so as to prove our technology capability.

Veba (Petrocanada)
Target Ghani Zenab either through acquisition or asset swap.

Wintershall
Target Nakhla and As Sarah through acquisition or asset swap.

Zuetina (Occidental)
Leverage access to Sabah EOR development in exchange for partnership in EOR masterplan project, but only once HOA agreed with NOC.

4.3.2 Crown Jewels
The largest fields in Libya (Table 3) may be regarded as the 'crown jewels' and are known to be politically sensitive. The list below shows the largest 15 fields and essentially comprises fields that are controlled by the NOC. Initial entry via these largest fields is considered to be unlikely although their large size makes them attractive. The largest field in Libya is operated by Veba (Petrocanada) and this in itself may be an opportunity that can be accessed by partnering or swap/acquisition. Similarly, Bu Attifel, which is operated by Eni, may be an attractive target for partnering or acquisition given that Eni also operates the best CO_2 source.

STOIIP (MMstb)	Best EOR Increment (MMstb)*	Operator	Field	Comment
17000	1360	Veba	Amal	EHG/CO_2 WAG potential by analogy to other fields
14000	1120	Waha (Oasis)	Gialo	Very large Polymer potential. Access possible through Oasis partners?
12987	1040	Waha (Oasis)	Dahra East-West	Comprises two accumulations. Access possible through Oasis partners?
9536	760	AGOCO	Sarir (65C)	V. Large EHG/CO_2 WAG potential
6885	550	Waha (Oasis)	Waha	Access possible through Oasis partners?
6660	530	AGOCO-Zuetina (Occidental)	Augila-Nafoora	Crestal gas injection or EHG/CO_2 WAG potential

6000	480	SOCO	Nasser	V. Large EHG/CO_2 WAG potential
5600	450	Eni	Bu Attifel	IOC operated. EHG/CO_2 WAG potential by analogy to other fields
4400	350	Waha (Oasis)	Defa	Access possible through Oasis partners?
3776	300	Waha (Oasis)	Masrab	Access possible through Oasis partners?
3000	240	AGOCO	Beda	
3000	240	Waha (Oasis)	059-6J-001	Access possible through Oasis partners, although field discovery post-dates Oasis involvement.
2930	230	AGOCO	Messla	Large EHG/CO_2 WAG potential.
2014	160	Zuetina (Occidental)	Intisar 103D	Crestal gas injection scheme ongoing
1875	150	SOCO	Raguba	EHG/CO_2 WAG potential.

Table 3 Largest fields in Libya. (*Incremental EOR volumes are based on an average incremental recovery of 8% of STOIIP for studied Sirte Basin fields and are rounded to the nearest 10)

Veba (Petrocanada)
Target Amal entry either through acquisition or asset swap.

Waha (Oasis)
Access to Dahra East-West, Defa and Gialo would represent very significant opportunities and could be considered through acquisition of or partnering with one of the Oasis partner companies (Amerada, Marathon and Conoco). The materiality of the fields could justify considering such a move.

AGOCO and SOCO Fields
Access is unlikely for political reasons, however as part of the greater EOR masterplan technical services could be provided.

ENI

4.3.3 CO_2 Source Field

The NC041-D-002 field is currently controlled by ENI. Options for gaining access need to be considered and evaluated. These could be:

- As part of a greater corporate acquisition strategy
- Acquisition of the field itself
- ENI to participate in the EOR master plan project in return for a share in the field

4.4 Strategy for the evacuation/monetisation of oil and gas produced

The oil and gas pipeline infrastructure in the Sirte basin is predominantly controlled by the NOC and so access to ullage should be reasonably straightforward. Available ullage will be assessed as part of the EOR Masterplan.

4.5 Farm-in opportunities

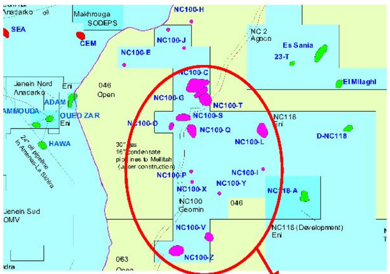
4.5.1 NC-100/101

An opportunity exists to farm into two explored but undeveloped brownfield Libyan assets (NC-100 & NC-101) currently held by Bulgargeomin (previously BOCO) a Bulgarian state oil Co.. The asset licenses will expire at the end of March 2005 unless the Bulgarians can show that they have a credible partner willing to develop the assets; in which case the government has indicated that they will receive an extension to the license.

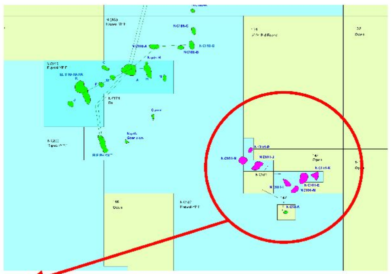
Associated with this the opportunity, in the Murzuk basin, to resurrect project Stephenson, so as to increase regional materiality and/or as potential leverage for preferential access to ENI infrastructure. The access to material oil in Libya supports the creation of a position in a new target heartland for Shell.

The NC-100 asset is in the Ghadames basin region (see figure 5). A region dominated by ENI and considered of low prospectivity by EPX. The economics are not profitable under any existing EPSA environment unless the government take ratio can be reduced significantly. In addition there are marginal oil and gas volumes and the opportunity is a long distance from our intended Sirte heartland plays linked to the Brega plant for gas monetisation. Gas from

Ghadames



Murzuk



Data	NC-100	NC-101
EPSA II Shares	NOC 85% Bulgargeomin 15%	NOC 85% Bulgargeomin 15%
Discovery Date (undeveloped)	1980-87	1980-85
Oil Quality (API)	41	36
STOIIP (mmbbl) GIIP (BCF)	301 350	525
Recoverable Reserves Oil (mmbbl) Gas (non assoc./assoc.) (BCF) Condensates	 100 240/126 6	 200 0/60
Anticipated Peak Production Oil (kbbl/d) Gas (non assoc./assoc.) (mmscf/d)	 28 50/34	 68 0/20
Exploration upside	10% probability of 35% increase in gas reserves	10% probability of 25% increase in oil reserves

Base Case Economics

Fiscal Terms \ Oil Price		USD 25 US$MM
NC-100 EPSA II	NPV7RT	(311)
	VIR	(0.72)
NC-100 EPSA IV	NPV7RT	(28)
	VIR	(0.13)
NC-101 EPSA II	NPV7RT	(122)
	VIR	(0.35)
NC-101 EPSA IV	NPV7RT	100
	VIR	0.57

NC-100 would need to be monetized through the ENI's 'Greenstream' pipeline for a fee.
Figure 5

The NC-101 asset is in the Murzuk basin region (see figure 5). The asset contains material light oil with minor amounts of associated gas. The volumes of oil when considered on their own would not be enough to justify a country entry, however are significant as part of a staircase strategy to build a new heartland in a major resource holding country. The Murzuk is dominated by ENI and Repsol and is considered as low-moderate prospectivity by EPX. Though the asset is relatively isolated, access to the Elephant (ENI) and El Sharara infrastructure should be possible. Project economics (including the full cost of a new pipeline) under currently available EPSA IV terms are attractive generating an NPV(7) of USD 100 mln (VIR 0.57).

4.5.2 Project Stephenson

Through Project Stephenson ENI has an obligation to Shell as a result of Shell's support to ENI acquiring operatorship of the OKIOC consortium in March 2001.

MOU description of obligation signed on 20.03.01:
• Shell has option to acquire 16.67% interest in the Elephant field at FMV less 5 %, but the parties will endeavour ro find an appropriate Shell asset to be swapped as a consideration
• Shell has an option to acquire 33.3% participating interest (= 50% of Agip interest) in block NC174 exploration license

An attempt was made in 2002 to find an asset deal to compensate Shell. No deal was ever concluded and the deal has lapsed.

4.5.3 Forward Plan

The plan depends on whether engagement is possible with Bulgargeomin post 20th January termination of their exclusive negotiations with a 3rd party. In the case that the opportunity is still available the next steps are:

- Engage with Bulgarian Government to explore the possibility or not to separate NC-101 from NC-100
- Engage with ENI to explore access to Murzuk infrastructure and the potential options around project Stephenson resurrection and further joint opportunities in the Murzuk basin
- Engage with Libyan government on the potential to improve terms for NC-101 and NC-100 so as to make them profitable once EPSA III negotiations are finalised
- Pursue NC-101 negotiations without NC-100 unless NC-100 terms can be dramatically improved

4.6 Acquisition targets

For many companies operating in Libya, their Libya assets form only part of a greater portfolio. Due to the current perceived attractiveness of Libya it is unlikely that a company will divest its Libya assets willingly alone unless forced to do so or unless associated with an extremely high premium to the purchaser. The acquisition by Shell of a company for its Libya portfolio alone would also need to be justified based on the potential added value from the rest of the portfolio either on integration with the Shell portfolio or through on-selling post acquisition.

Corporate acquisition targets are being considered as part of the Cluedo process. The following companies with Libya assets are being considered:

Occidental – Zuetina assets and CO2 technology/experience
Repsol – Libya oil assets and exploration acreage
Marathon – Libya assets as part of Oasis group
Amerada Hess – Libya Assets as part of Oasis group
OMV – Libya exploration acreage

4.7 Swaps

An alternative route to obtaining all or part of a competitors interest in Libya could be through asset swaps. This route is currently preferred within Shell at present as the current period of portfolio restructuring comes to an end and routes to growth are focused on.

i) Oscar
Through this project between USD 1-200 million worth of Shell assets will be available for swaps with interested parties. A Company with Libya assets of interest to Shell that can be expected to express interest are Wintershall and OMV.

ii) Wentworth
Through this project between USD 6-700 million worth of Shell assets are expected to be available for swaps with interested parties. A Company with Libya assets of interest to Shell that can be expected to express interest are Petrocanada (Veba).

4.8 Partnering evaluation

Partnering needs to be assessed on an opportunity by opportunity basis for individual brownfield asset plays that become available. For broader projects such as the EOR masterplan, partnering should be considered for the partners ability to bring something that we lack such as access to assets and/or applicable technology. For the development of the EOR masterplan, partnering options would be attractive for:

i) ENI (Access to Assets and CO_2 supply)
Partnering with ENI could be necessary to gain access to their Pelagian basin assets. In addition ENI are one of the best placed operators in Libya with gas evacuation infrastructure to the EU market through their Greenstream pipeline to Italy. In total, ENI assets account for 6.4 MMstb STOIIP and 0.44 MMstb of EOR oil potential in the Sirte basin. ENI are not a major source of EOR potential and so not as attractive as others on this basis.

ii) Sirte Oil Co. (Access to Assets and CO_2 supply)
SOCO are the only NOC company without historical partnership ties with Western IOCs. SOCO are operators of a number of EOR target fields such as the medium sized fields Jebel and Raguba, which if combined with CO_2 from the Atahadi field could prove the core of our EOR master plan. In total, SOCO assets account for 10 MMstb STOIIP and 0.68 MMstb of EOR oil potential in the Sirte basin. EOR potential from SOCO assets is substantially less than for other NOC subsidiaries.

iii) Oasis/Waha (Access to Assets)
The presence of Oasis is dependant on successful negotiations with the NOC. In the case that they are able to return to the operatorship of their original assets, as can be seen from Table 3, these assets would represent some of the most material targets for a CO_2 WAG EOR strategy. In total, Waha assets account for 53.2 MMstb STOIIP and 3.6 MMstb of EOR oil potential in the Sirte basin.

iv) AGOCO (Access to assets)
In total AGOCO assets account for 24.8 MMstb STOIIP and an estimated 1.7 MMstb of EOR oil potential in the Sirte basin. Partnership with AGOCO on EOR should be considered if access to 'crown jewel' fields seems possible.

v) Petro-canada (Access to assets)
In total Petro-canada assets account for 23.3 MMstb STOIIP and an estimated 1.6 MMstb of EOR oil potential in the Sirte basin. Partnership with Petro-canada on the development of the EOR potential for the Amal field should be assessed.

iv) Occidental (Access to Technology)
The worlds largest operator of CO_2 floods through their Altura venture. This partnership would bring in CO_2 injection technology and experience and remove a potential competitor

already present in Libya. In addition their current presence in Libya could bring useful government contacts.

v) ExxonMobil (Access to Technology and Risk Sharing)
EM are second only to Occidental in experience with CO2 flooding technology from operations in the Permian basin. We have a good track record with EM elsewhere and US government support could be beneficial in Libya. EM are likely to be attracted to a large scale high capital project.

In order to improve our access and quality of relationships with the NOC it has been felt that we might benefit from a partnership with a Libyan independant operator. We have been approached by ODEX through SAQ. We have rejected this option due to the lack of synergy between our business drivers and one of their shareholder companies.

However Oilinvest, an investment arm of the Libyan NOC, could represent another potential angle

4.9 2005 EOR bid round
The NOC has mentioned that it would be interested in 2005 to hold a bid round for the EOR development of a number of fields. It is expected that these will be medium sized fields and not the 'crown jewel' assets. Shell will need to be prepared to assess the potential of any opportunity offered in this bid round. If we are to proceed with our EOR masterplan concept it would be crucial to present the concept to the NOC before they finalise their EOR bid strategy as it has the potential to change their whole EOR development strategy.

4.10 General Conclusions and Recommendations

i) IOR/EOR technology screening has show that the Sirte Basin has significant miscible WAG potential. There is limited polymer potential and no thermal potential. Therefore an EOR strategy requires a source of either enriched hydrocarbon gas or CO_2.

ii) The interests of Libya are believed to be best served by maximising the amount of hydrocarbon gas for monetisation..

iii) Preliminary study of gas resources suggests that there is insufficient free hydrocarbon gas in the Sirte basin for both gas monetization and full development of the Sirte basin EOR potential. The use of CO_2 as the gas injection agent for EOR would provide a route to freeing up gas for export at the same time as releasing gas associated with the CO_2 in the source field and to a lesser extent gas associated with the oil recovered through the process. This supports our LNG strategy

iv) There are limited significant CO_2 sources in the Sirte basin (Hateiba and Atahadi). These would be sufficient for a couple of medium sized EOR projects, however it is therefore highly likely that CO_2 will need to be sourced from other basins if the full EOR potential of the Sirte basin is to be developed. The largest single source of sufficiently pure CO_2 is NC041-D-002 field in the Pelagian Basin.

v) An EOR master plan project to supply CO_2 of sufficient quantity to develop the full EOR potential of the Sirte basin should be developed and proposed to the NOC, as a project that allows them to maximize both oil recovery and gas monetization in parallel.

vi) A two step process to the implementation of the EOR master plan should be considered where our technology is initially show cased on a medium sized field with CO_2 from a

Sirte basin source such as the Atahadi field operated by SOCO, followed by or in parallel to development of the broader basin wide plan.

vii) The key strategic control points are:

- Access to oil producing fields for the application of EOR technology
- Access to CO_2 source fields
- Access to CO_2 injection technology
- Access to CO_2 and HC gas separation technology

viii) The key strategic control points are currently not held by Shell except a newly developed and untested gas separation technology

ix) In the short term access to EOR target fields, CO_2 source fields and CO_2 injection technology will need to be through partnerships, swaps or acquisition plays with NOC subsidiaries or IOC incumbents. In the longer term access through exploration success will be crucial.

x) Strategies for accessing the ENI operated NC041-D-002 field in the Pelagian Basin need to be developed including potential partnering on the EOR master plan and development of the Bu Attifel asset.

xi) Partnering with SOCO for the development of the EOR master plan through access to EOR target fields combined with access to Atahadi as a CO2 supply source should be seriously assessed.

xii) Access to EOR target fields through partnership, asset swap/acquisition opportunities with Petrocanada should be pursued vigorously.

xiii) Access to fields with EOR potential held by AGOCO and Waha should be investigated as part of the second phase of the EOR master plan.

xiv) Corporate acquisition of or swaps with Amerada Hess and Marathon for their Oasis interests should be assessed (Project Cluedo to cover)

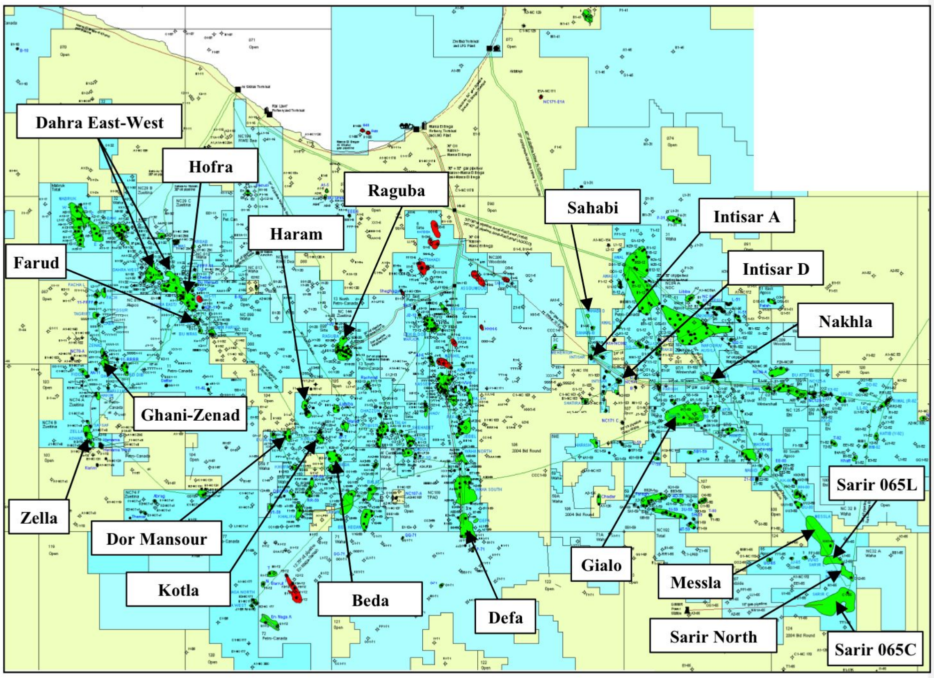
xv) A review of Shell's CO_2 injection technology capabilities needs to be assessed and the need to partner with Occidental or not should be determined.

xvi) The NC-101 opportunity is to be vigorously pursued within the agreed mandate.

Appendix 1

Field	Operator	Field STOIIP MMstb	Reservoir	Reserves MMstb
Haram (047-S)	Arabian Gulf Oil Co	950	Haram Lst	
			Hofra Fm	
Wadi (104-D/NC149-D/K)	Sirte Oil Co	391	M59	45
			Nubian	44
			Gargaf	5
Sarir (065-L)	Arabian Gulf Oil Co	1774	Sarir	840
Lehib-Dor Marada (006-UU/013-T)	Sirte Oil Co~Veba	375	Waha	150
			Bahi	
			Hofra Fm	
Dor-Mansour (047-Z/104-A)	Arabian Gulf Oil Co	291	Lidam Fm	116
Kotla (047-C/P/R)	Arabian Gulf Oil Co	671	Kalash	217
Sarir North (065-C)	Arabian Gulf Oil Co	658	Sarir	121
Jebel (006-P/4B)	Sirte Oil Co	750	Sheghega Fm	20
			Gargaf	
			Waha	200
Raleh (006-DD)	Sirte Oil Co	204	Waha	40
			Hofra	30
Magid (105-A/080-Z)	Arabian Gulf Oil Co	290	Sarir	90
Raguba (020-E)	Sirte Oil Co	1875	Waha	730
			Hofra Fm	
			Mabruk	20
Ghani-Zenad (011-RRR/VVV)	Veba	850	Hon Evap	15
			Facha Dol	135
			Kalash Fm	
			Al Farud	150
Sahabi (095-D)	Arabian Gulf Oil Co	105	U Sabil	31
Latif (NC059-A/C)	Arabian Gulf Oil Co	100	Gialo	40
			Tagrifet	
			Lidam Fm	

Field	Operator	Field STOIIP MMstb	Reservoir	Reserves MMstb
Nakhla (097-G)	Wintershall	1000	Calanscio	150
Hofra (011-A/4O)	Veba	1788	Dahra	254
			Thalith Mbr	4
			L Satal Mbr	32
Ora (013-H/I)	Veba	500	Ora	15
			Kalash Fm	
			M59	45
			Hofra	50
En Naga North (NC177-B)	Petro-Canada	2004	Facha Dol	26
			Zelten Lst	20
			Beda	7
Eteila (013-G/HH)	Veba	250	M59	53
			Lidam Fm	47
Facha (011-L/O)	Veba	174	Facha Dol	12.5
			Mabruk	29
			Al Farud	0.5
Farigh (012-AA)	Veba	150	Sarir	50
As Sarah (096-B)	Wintershall	1000	Pre U Cret	550
Tagrifet (011-QQQ)	Veba	100	Facha Dol	23.5
			Dahra Fm	0.5
Farud (011-JJ)	Veba	150	Dahra Fm	50
Ed Dib (011-GG)	Veba	100	Facha Dol	2
			Hon Evap	18
Rakb (012-D)	Veba	145	Rashda	50
			Basement	15
Sabah (078-G/NC131-B/NC074F-G)	Zueitina Oil Co	482	Beda C	224
Zella (NC074B-A)	Zueitina Oil Co	450	Facha Dol	150


Dahra East-West
Hofra
Raguba
Sahabi
Intisar A
Haram
Farud
Intisar D
Nakhla
Ghani-Zenad
Sarir 065L
Zella
Dor Mansour
Gialo
Messla
Kotla
Beda
Defa
Sarir North
Sarir 065C

Appendix 2

In all, data was available for 20 fields and these were studied in more detail so as to define which EOR technique would be most appropriate in each case. In many cases the fields are to be found on the priority ranked list and in other cases they are different fields but with analogous reservoirs.

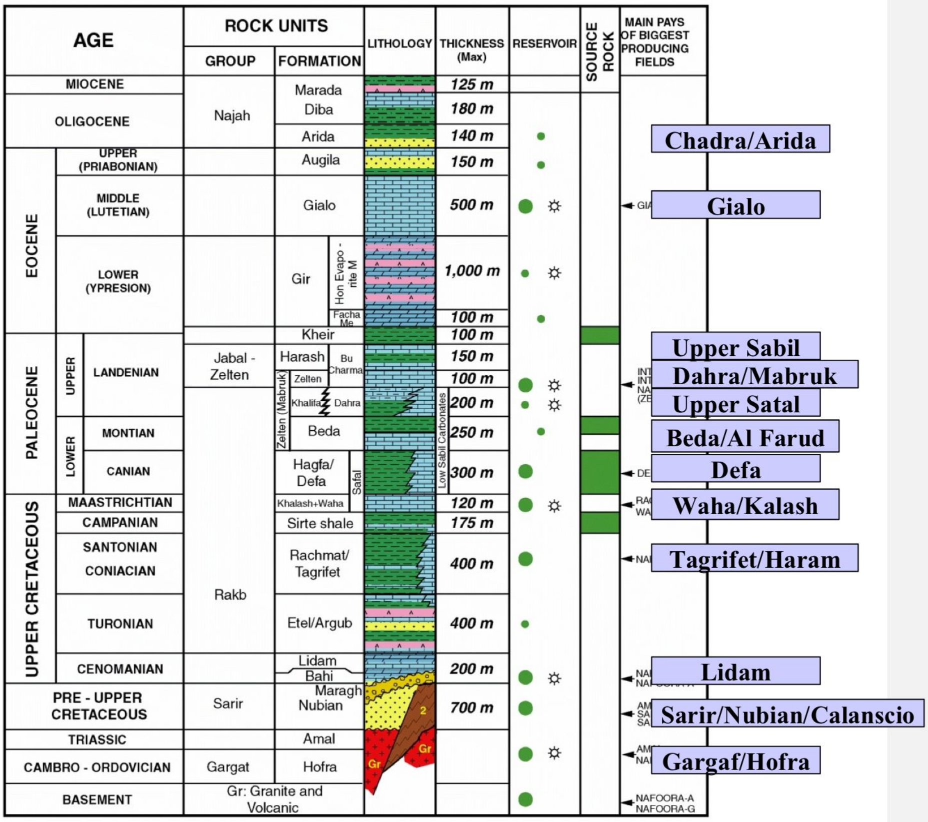


Diagram 1

In general it should be commented that it was possible to get data for a reasonable number of reservoirs that gives a good coverage of reservoir types at different depths (see diagram 1) found in these selected fields though there is very little fluid data. This coverage allows for analogues to be drawn for fields where no data is available.

The study clearly showed (See diagram 2) that there is a wide range of reservoir types with scope for the following EOR techniques:
i) Crestal gas injection (e.g. implemented Intisar pinnacle reef structures)
ii) Miscible WAG
iii) Polymer
There is no scope for thermal EOR recovery techniques. One EOR technology area where we have significant knowledge and experience through our activities in Oman.

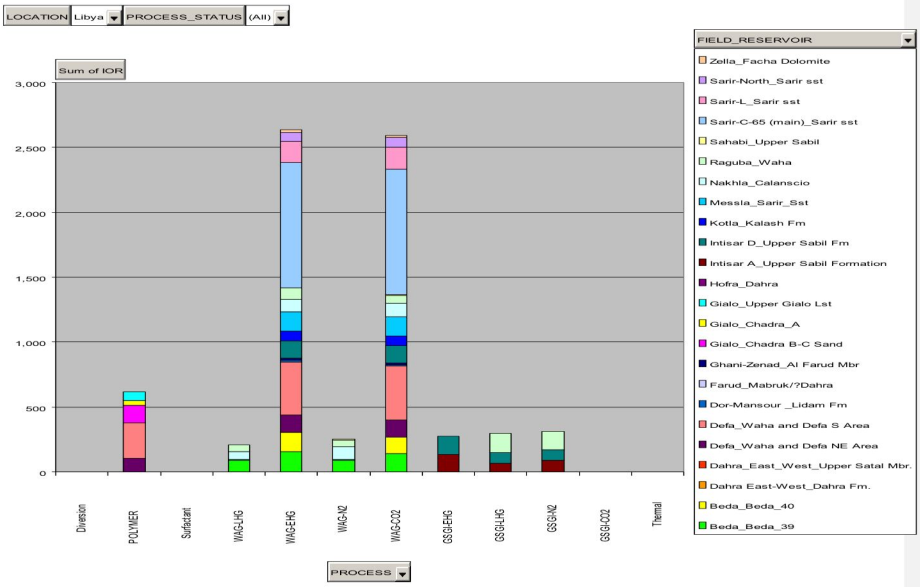


Diagram 2 EOR potential (MMstb) for EOR processes broken down by reservoir. (Performance Indicator estimates only, quantitative assessment requires use of Rapid Simulation screening)

Clearly there is most significant scope for WAG-EHG (Water Alternating Gas – Enriched hydrocarbon gas) or WAG-CO_2 (Water Alternating Gas – CO_2) with both processes yielding potentially around 2.6 bln stb of recoverable oil across all 18 fields together.

Appendix 3

Field	Operator	Field STOIIP MMstb	Reservoir	Initial Reserves MMstb	Chemical			WAG				GSGI				Thermal	Best EOR Increment from Performance Indicators (MMstb)	Comments
					Flow diversion	Polymer	Surfactant	Lean HC	Enriched HC	Nitrogen	CO2	Lean HC	Enriched HC	Nitrogen	CO2	Steam		
Haram (047-S)	Arabian Gulf Oil Co	950	Haram Lst															Results based on current study integrated with earlier Shell report (EP2001 5632)
			Hofra Fm															
Wadi (104-D/NC149-D/K)	Sirte Oil Co	391	M59	45														Insufficient Data Nubian Compare with Sarir, Messla, Nakhla
			Nubian	44														
			Gargaf	5														
Sarir (065-L)	Arabian Gulf Oil Co	1774	Sarir	840													159	
Lehib-Dor Marada (006-UU/013-T)	Sirte Oil Co~Veba	375	Waha	150														Incomplete layering scheme for Waha compare with Defa and Raguba fields
			Bahi															
			Hofra Fm															
Dor-Mansour (047-Z/104-A)	Arabian Gulf Oil Co	291	Lidam Fm	116													10	
Kotla (047-C/P/R)	Arabian Gulf Oil Co	671	Kalash	217													79	
Sarir North (065-C)	Arabian Gulf Oil Co	658	Sarir	121													72	
Jebel (006-P/4B)	Sirte Oil Co	750	Sheghega Fm	20														Insufficient Data for Waha compare with Defa and Raguba
			Gargaf															
			Waha	200														
Raleh (006-DD)	Sirte Oil Co	204	Waha	40														Reasonable quality geological data. Compare Waha with Defa and Raguba Fields
			Hofra	30														
Magid (105-A/080-Z)	Arabian Gulf Oil Co	290	Sarir	90														No data; compare with Sarir Messla Nakhla
Raguba (020-E)	Sirte Oil Co	1875	Waha	730													144	
			Hofra Fm															Mimimal data; Compare Mabruk with Farrud and Hofra
			Mabruk	20														
Ghani-Zenad (011-RRR/VVV)	Veba	850	Hon Evap	15														Insufficient Data for Facha Dol compare with Zella
			Facha Dol	135														
			Kalash Fm															
			Al Farud	150													15	
Sahabi (095-D)	Arabian Gulf Oil Co	105	U Sabil	31													6	
Latif (NC059-A/C)	Arabian Gulf Oil Co	100	Gialo	40														Mimimal data; for Gialo compare with Gialo
			Tagrifet															
			Lidam Fm															
Nakhla (097-G)	Wintershall	1000	Calanscio	150													93	
Hofra (011-A/4O)	Veba	1788	Dahra	254													0	
			Thalith Mbr	4														Minimal data
			L Satal Mbr	32														Poor data compare with Dahra East West
Ora (013-H/I)	Veba	500	Ora	15														Minimal data
			Kalash Fm															
			M59	45														Variable quality field specific data, best for M59 reservoir (compare with L.Beda in Beda)
			Hofra	50														
En Naga North (NC177-B)	Petro-Canada	200.4	Facha Dol	26														Variable but generally poor quality data Facha Dol compare with Zella
			Zelten Lst	20														
			Beda	7														
Eteila (013-G/HH)	Veba	250	M59	53														Minimal field specific data. For M59 compare with lower Beda Fm, for Lidam Fm compare with Dor Mansour
			Lidam Fm	47														
Facha (011-L/O)	Veba	174	Facha Dol	12.5														Moderate to good geological data compare Facha Dol with Zella and Mabruk with Dahra
			Mabruk	29														
			Al Farud	0.5														
Farigh (012-AA)	Veba	150	Sarir	50														Good geological data, compare with Sarir, Messla, Nakhla
As Sarah (096-B)	Wintershall	1000	Pre U Cret	550														Incomplete layering data
Tagrifet (011-QQQ)	Veba	100	Facha Dol	23.5														Minimal field specific data
			Dahra Fm	0.5														
Farud (011-JJ)	Veba	150	Dahra Fm	50													0	
Ed Dib (011-GG)	Veba	100	Facha Dol	2														Limited field specific data. Incomplete section for layering scheme. Compare with Zella field
			Hon Evap	18														
Rakb (012-D)	Veba	145	Rashda	50														Insufficient data for layeirng scheme, but Rashda is only seen in 3 fields (rec res <60 MMstb)
			Basement	15														
Sabah (078-G/NC131-B/NC074F-G)	Zueitina Oil Co	482	Beda C	224														Layering data available; compare with Beda field
Zella (NC074B-A)	Zueitina Oil Co	450	Facha Dol	150													17	
Beda (047-B)	Arabian Gulf Oil Co	3000	Beda 39 unit	1350													158	
			Beda 40 unit														146	
Dahra East-West (032-F/B/Y)	Waha	12987	Dahra Fm.	1800													0	
			Upper Satal Mbr.	325													0	
			Harash Fm															Minimal data
			Thalith Mbr	42														
Defa (059-B/071-Q)	Waha	4400	Waha and Defa S Area	2400													412	
			Waha and Defa NE Area														133	
Gialo	Waha	14000	Chadra_A	128													34	
			Chadra B-C Sand	396													134	
			Upper Gialo Lst	933													65	
			U Sabil Carb Fm	225														Compare with Intisar A and B
			Jakhira Fm	21														Minimal data.
			Al Gata Mbr	9														
Messla (065-HH/080-DD)	Arabian Gulf Oil Co	2930	Sarir_Sst	1245													149	
Intisar (103-A)	Zueitina Oil Co	1500	Upper Sabil Fm	1050													136	
Intisar (103-D)	Zueitina Oil Co	1760	Upper Sabil Fm	1325													139	
Sarir (065-C)	Arabian Gulf Oil Co	9536	Sarir sst	4482													966	

EOR performance matrix for studied Sirte Basin fields, where blue indicates that a process is potentially applicable and red indicates no potential. Where reservoir interpretations are based on analogous reservoirs a lighter shading has been used.

Appendix 4 Gas and NGL Requirements

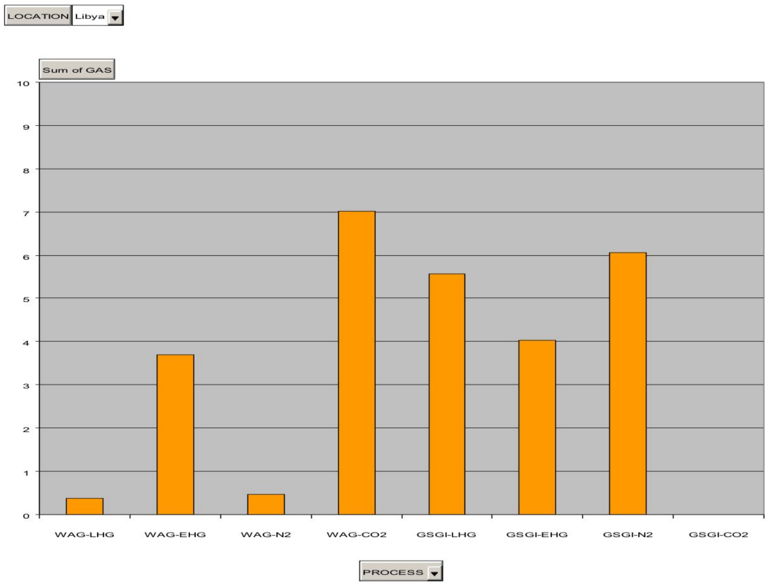


Figure 1: Net Technical Gas Requirements (Tscf) for different gas injection processes. (Performance Indicator estimates only, quantitative assessment requires use of Rapid Simulation screening)

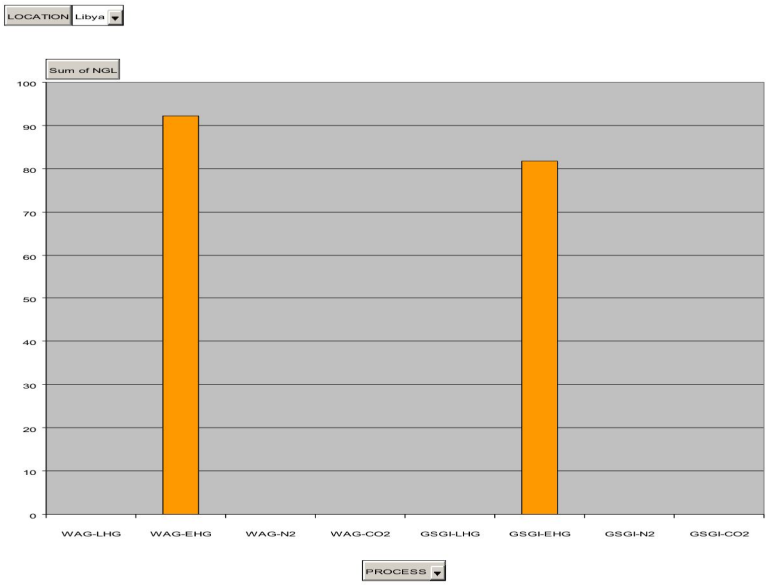
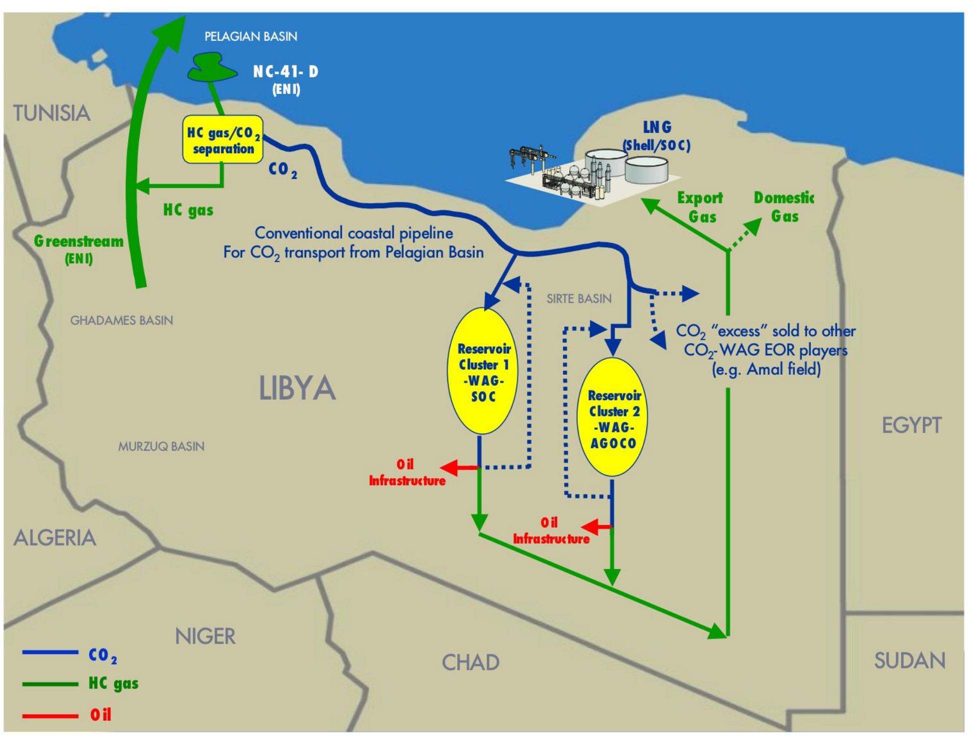


Figure 2. Net NGL requirements (mln tonnes) for enriched hydrocarbon gas techniques. (Performance Indicator estimates only, quantitative assessment requires use of Rapid Simulation screening)

Project Black

Script for ECMB/ECLC Libya Meetings

Shell believes a window of opportunity exists for Shell in Libya to participate in shaping Libya's secondary/tertiary field development strategy in the Sirte basin through undertaking a one year joint feasibility study under an MOU.
The attention of NOC is expected to shift in 2006 from the EPSA 4 exploration bid rounds to finalising the approach towards development contracts on existing fields. It is likely that there will be another bid round in the latter half of 2006 where medium sized discovered and undeveloped assets will be put out to bid.
The debate continues within Libya as to the benefits of a bid versus a negotiated approach to field development contracts. The current feeling is that if development contracts for 'crown jewel' assets are to be awarded it will be based on negotiated deals for which a differentiated value proposition can be defined.
In addition it is expected that 2006 will be the year in which NOC will define the strategy for the development of IOR/EOR options. Currently a debate exists within NOC as to the need for partnering on the large field developments. NOC feel confident to be able to develop IOR waterflood projects themselves but are not so confident on EOR. Due to the shortage of currently available hydrocarbon gas and Libya's gas export aspirations, CO_2 WAG has been identified in NOC studies as the key EOR technology. NOC recognise a need for external parties to supply them with capability in the area of CO_2 and CO_2 WAG infrastructure development.
There is a model in NOC's mind where they develop the IOR programs first and deal with CO_2 WAG EOR later. Unfortunately this will prove potentially inefficient as the well patterns for successful future CO2 WAG injection need to be planned and drilled during the water injection phase. From Shell's experience in leading the Permian basin CO_2 WAG development in the 1970/80's sufficient fields need to be ready for simultaneous CO_2 WAG injection, once CO_2 is delivered to the basin, so as to be able to justify the significant CO_2 source field/pipeline capital costs.
Shell has constructed an integrated solution (Project Black) to Libya's perceived needs in this area that we would like to propose to and verify with you.



Project Black is a multi-billion dollar scheme that will significantly extend the producing life of the Sirte Basin:

- Major field redevelopment scheme with integrated waterflood and CO_2 WAG, first oil 2011 with 40+ year project life. Incremental production plateau of over **400,000 bbls/d** for **20 years**.
- Expect 15-20% increase in ultimate recovery across covered fields (Over **4 bln bbls** from around one third of the Sirte STOIIP)
- Early injection of CO_2 in reservoir pilots (2011), followed as soon as practicable by basin wide CO_2 WAG
- Monetization of otherwise un-commercial Pelagian Basin CO_2 (**12 Tscf**) and hydrocarbon gas (**2Tscf**)
- Largest CO_2 transport project (**1 Bscf/d**) in the world
- Significant infrastructure and SD program that is yet to be defined, but will be based around the scope of the project

Shell is well placed to offer this integrated solution as we combine competitive strength in the following areas:

- Leading CO_2 WAG experience and technology for developing the CO_2 source field, gas separation, pipeline and target fields (Permian Basin history – Altura/Denver Unit)
- Proprietary gas separation/low cost pipeline technology
- Access to capital
- Ability to integrate/coordinate complex world scale projects down the value chain (ref. Learnings from Sakhalin, Kashagan etc)
- Leading technology player committed to remaining a leader (ref. CEJVs 8 chief scientists etc)
- Good established relations with Libyan NOC with in-country operations
- Mubadala as a potential partner for political leverage and infrastructure/SD development reasons
- British/Dutch government relations/support

Others are well placed too. NOC alone and Occidental are potential competitors but are believed not to have the access to capital/resources to pursue this alone. Due to the scale of the project, the most significant perceived competitive threat is believed to come from ExxonMobil, bp and ChevronTexaco. The areas where they are differentiated from us are:

EM

Have retained CO_2 WAG demonstrator capability in Permian. Have some 'claim' to SOC assets. US companies re-entry hampered in short term by Libya’s continued presence on 'state sponsors of terrorism list' and human rights issues (Bulgarian Nurses)

BP

Have massive HC miscible flood experience from Prudhoe Bay operations. Have some 'claim' to AGOCO assets. But not present in Libya at present

ChevronTexaco

Have CO_2 WAG production in the Permian basin. However they are a new-comer to Libya with no claim to existing assets. ChevronTexaco have stated to Shell at IPTC that they have made a proposal to NOC to partner with AGOCO for IOR/EOR in the Sirte basin. No response has been forthcoming to date.

Even for the super-majors the scale of this project is large and therefore it is likely that a consortium approach will be favored. This could suit NOC for political reasons as they will find it hard/impossible to justify working in partnership with one IOC alone in this key area. However it is considered appropriate at this stage to offer our proposed solution to NOC alone. If partnering issues are raised then we should show a willingness to work with the appropriate ones.

If the atmosphere in discussions with government ministers and NOC is conducive, it is proposed to raise project Black as a proposal to support Libya's oil production aspirations over the long term. It is requested that you indicate support from the highest levels of Shell for a project of this scale/vision. The main objective is to set the scene for a more formal proposal to NOC in the early new year. It is intended for the formal proposal to lead to an MOU as the foundation to a one year Shell funded joint feasibility study.

At no time should we indicate that we want access to specific 'crown jewel' assets. This will of course be implicit, but extreme sensitivity around these assets exists and any conclusions should come from NOC themselves over the joint feasibility study period. We are in effect offering to perform a service with them.

If the discussion progresses, then it should be stressed that Shell will share one of many potential visions for a fully integrated solution, but stress that we recognise that ultimately NOC will decide, following the joint feasibility study period, the participation level of IOCs. In the discussion we should show openness to working with others in the final solution as long as materiality is maintained. If pushed on this then indicate that this would normally constitute Shell production of around 100,000 bbls/day which could be 'production in kind'.

Meeting with PetroCanada
Date 2nd October 2005
Present :

PetroCanada :
Ian McIntosh GM
Jim Bradley Director Business Development
Juergen H. Rodefeld Manager Busines Development

Shell
Bruce Levell
Jan Willem Eggink

Messages Received

- We have no news on the EPSA III block that is pending ratification. Were told by NOC "to hold on"
- We would like SGSI to help, Shell is ahead and we believe working with Shell (and SGI) may help our case
- Current terms in EPSA III very favourable, and expect we need to renegotiate
- We have no title to gas in other contracts (that needs renegotiation)
- We believe a meeting between Matthias and Peter Kallos is now timely
- We apprecaite that you do not wish to use political power for our cause
- We have no appetite to invest in refineries (apart from e.g. preFEED and FEED)
- Took Saif Ghaddafi to refinery in Canade
- We can also offer refinery services ourselves, but belive with Shell may be better

Messages Given

- Our EPSA III deal bruised the Libayn system
- We do not wish to exert pressure on goverment for PetroCanade, guess you understand that
- We have good relationship with embassies, in particular UK
- We do not want to invest in refineries
- Need to be clear what your expectations are of Shell in any deal jointly with PC. What if we cannot deliver?
- Any deal with PC need to be PC led with Shell in the shadow
- We may help you in keeping BP away, they are looking at Agoco acreage
- BP and XOM are approaching Libya through the leaders, not from bottom up through NOC, this is not smart (confirmed in the evening by BP itself)
- We are interested in deeper gas. Could focus first on this, then on brownfield. This may be a way to split the Vaba acreage.
- Instead of refineries a deal can be made unique with e.g. science park
- Linkage between your acreage and a refinery is weak (our unique deal hangs together better)
- Happy to assist with SGSI
- A meeting with EPX around 12th October is timely. If we have a positive way forward then form a joint commercial team