Understanding Middle East Gas Exporting Behavior

Axel M. Wietfeld*

The Middle East is a fascinating region with an immense GDP growth and an excellent business environment. Thanks to its huge hydrocarbon reserves, the region already exports a lot of oil and gas and has realistic plans to increase this further. Although the global gas market is currently saturated and will be so for the next years, the hunger for additional supplies is likely to reappear in the second half of the new decade. Consequently, the gas exporting nations in the Middle East, such as Qatar, the UAE, Oman and Iran have to prepare themselves for developing additional projects. The question discussed in this article is whether they are able to do so, given challenges such as high indigenous demand, energy inefficiency, reserve structures and the sometimes unstable political environment, which is making it difficult to attract the required capital.

This review begins with a brief overview of each country’s reserve structure and natural gas history. It then proceeds to analyze the current and future supply/demand balance, taking into account the relevant pipeline and LNG export projects, and draws conclusions for future export projects.

The results suggest that Qatar, the UAE, Iran and Oman could contribute to global LNG and pipeline gas supplies with additional volumes of 55 to 90 bcm/a in the period 2015 to 2020.

1. INTRODUCTION

The Middle East (ME) is blessed with 40% of the world’s proven gas reserves and 60% of the proven oil reserves, which makes the region crucial for global energy supplies (BP 2010, pp. 6, 22). For the purposes of this review, the ME region is defined as the Arabian Peninsula countries plus Iran and Iraq, as

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opposed to a broader definition which spans south-western Asia, south-eastern Europe and north-eastern Africa and hence amounts to even higher reserves.

Natural gas is today considered by many as the fuel of the future. Years ago, when oil companies drilled for oil and found gas, their effort was—in most regions of the world including the ME—deemed a failure. As there were no market outlets, the gas often had to be reinjected, flared or left for another day. When flaring was branded as wasteful, companies had to find an alternative use for gas. Consequently, gas export projects were evaluated and, if viable, pursued as pipeline gas or liquefied natural gas (LNG)\(^1\) projects to serve the global market. As oil prices rose and production costs fell, LNG export projects with their high fixed cost structure became more economically feasible. Consuming nations in Asia, Europe and the US with long-term visions were willing to pay a premium to secure clean energy from diverse and reliable producers. Close cooperation developed between sellers in the ME and buyers on every aspect of the LNG chain—production, liquefaction, shipping and regasification.

Lovatt (2010, p. 1) points out that gas producers in the ME have reached a crossroads. The US shale gas revolution, combined with economic slowdown, has brought down global prices, while at the same time the financial crisis has cut project funding. The growing domestic demand, particularly in the ME, leads to reassessment of gas monetization priorities, and continued adherence to subsidies threatens sustained exploitation of challenging reserves. Currently, there seems to be sufficient gas available to meet global demand with even more projects coming on stream. However, in future, growing requirements in Europe, Asia and probably also in the US will cause markets to become tight again between 2015 and 2020,\(^2\) making the security of fresh gas supplies once again a top priority. This review examines the potential of these gas supplies by addressing the following main questions:

- Are the reserves sufficient to sustainably feed export projects?
- Does the increasing domestic demand in the ME allow for additional export projects?
- Do the LNG and pipeline gas suppliers have a suitable political environment and the financial strength to engage in further LNG and pipeline export projects?

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1. LNG (Liquefied Natural Gas) is natural gas that has been converted temporarily to liquid form (by cooling it to approximately \(-162^\circ\text{C}\)) for ease of storage or transportation. It takes up about 1/600th the volume of natural gas in the gaseous state and hence makes it much more cost-efficient to ship over long distances where pipelines are economically less efficient or strategically less preferable. LNG is transported by specially designed cryogenic sea vessels (LNG carriers). See also Wietfeld and Fenzl (2009, p. 16).

2. The IEA (2009, pp. 365, 425) suggests that gas consumption could bounce back globally from 2010, if the global economy recovers, rising by an average of 2.5% a year from 2010 to 2015 driven by increased gas burning for electricity generation. But gas supply is still likely to swamp demand until the latter part of the new decade, the IEA warns.
2. RESERVE SITUATION AND SUPPLY/DEMAND BALANCE

A sufficient reserve situation is a *conditio sine qua non* for the sustainable gas export potential of a country. In general, the ME has sufficient reserves for natural gas production on a very large scale. Figure 1 shows the distribution of proven natural gas reserves, which the World Petroleum Council (2007, pp. 8–11) defines as those reserves claimed to have a reasonable certainty (normally at least 90%) of being recoverable under existing economic and political/regulatory conditions, using existing technology.

The excellent reserve structure of the ME is sufficient to sustainably feed export projects. Its distribution among the countries is shown in Figure 2.

Iran and Qatar hold the second and third largest gas reserves in the world after Russia (BP 2010, p. 22). However, these countries are facing different challenges in terms of accessibility of the gas, domestic needs and their political environment which will be discussed below in more detail. The analytical focus in this article is on the established exporting nations Iran, Qatar, the UAE (United Arab Emirates) and Oman, as opposed to the new exporter Yemen. Potential
Figure 2: Proven Natural Gas Reserves in the ME [trillion m³]

future exporting nations such as Saudi Arabia, Iraq and Kuwait also have large gas reserves which, however, are today largely associated gas. As these countries prioritize oil production(exports over gas marketing, a significant increase of gas export volumes seems unlikely in the short-term, although in the long-term exploration and production (E&P) of non-associated gas can be assumed. Furthermore, the countries mentioned will have to cope with exponentially increasing domestic demand for natural gas, with the prime drivers being the petrochemical and the power generation sectors, i.e. gas demand in Saudi Arabia is forecast to double between now and 2025, which means an additional 155 bcm/a are required (Dutta 2010, p. 2).

The ME is facing a paradox, because while it has the highest reserves in the world, it only accounts for 12% of its production and is hence talking about a gas deficit (Lovatt 2010, p. 2).

The domestic needs of the exporting nations shown in Figure 3 are totally diverse. While Qatar has an enormous difference between production and consumption, Iran and the UAE face a high domestic demand. Oman, however, is hoping to increase its production (Dubere 2010, p. 3).
The main trigger for skyrocketing demand in the ME countries is their rising GDP (Gross Domestic Product). Figure 4 shows a comparison of the GDP per capita in this region, also in comparison to the world’s largest economy US.

The extent by which the UAE and especially Qatar are outperforming countries in the so-called Western world (e.g. the US) is amazing. It underlines the enormous economic potential of the ME, which is often underestimated.

Another reason for the high demand in the ME is the increasing population, combined with high energy intensity as shown in Table 1 (PRB 2009; EIA 2009a).

According to the definition by the US Department of Energy (2009), energy intensity is calculated by dividing total energy consumption\(^3\) by the GDP. It is thus an inverse function of energy efficiency.

There are many factors influencing an economy’s overall energy intensity including the standard of living and even weather conditions. It is not atypical

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3. Since the share of natural gas is different from country to country, it seems more accurate to use primary energy consumption rather than just gas demand.
Figure 4: GDP Per Capita in the ME

Source: International Monetary Fund, World Economic Outlook Database, October 2009 (based on current prices)

Table 1: Population, Energy Consumption and Energy Intensity

<table>
<thead>
<tr>
<th>2007 data</th>
<th>Population [million]</th>
<th>Primary Energy Consumption [Quadrillion BTU(^a)]</th>
<th>Energy Intensity [BTU per $]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Qatar</td>
<td>1</td>
<td>0.9</td>
<td>24.7</td>
</tr>
<tr>
<td>UAE</td>
<td>4</td>
<td>2.8</td>
<td>17.1</td>
</tr>
<tr>
<td>Iraq</td>
<td>28</td>
<td>1.2</td>
<td>14.0</td>
</tr>
<tr>
<td>Saudi Arabia</td>
<td>28</td>
<td>7.3</td>
<td>13.9</td>
</tr>
<tr>
<td>Iran</td>
<td>65</td>
<td>7.9</td>
<td>10.9</td>
</tr>
<tr>
<td>Kuwait</td>
<td>3</td>
<td>1.2</td>
<td>8.9</td>
</tr>
<tr>
<td>Oman</td>
<td>3</td>
<td>0.6</td>
<td>8.5</td>
</tr>
<tr>
<td>Yemen</td>
<td>22</td>
<td>0.3</td>
<td>5.8</td>
</tr>
<tr>
<td>United States</td>
<td>301</td>
<td>101.6</td>
<td>7.8</td>
</tr>
<tr>
<td>Germany</td>
<td>82</td>
<td>14.2</td>
<td>5.4</td>
</tr>
</tbody>
</table>

Source: EIA (2010)

\(^a\) British Thermal Units
particularly for hot regions such as the ME to need a lot of energy for cooling homes and workplaces. Furthermore, countries with an advanced standard of living are more likely to have a wider prevalence of consumer goods affecting their energy intensity than countries with a lower standard of living.4

High energy intensity is *inter alia* a function of poor energy saving. Consequently, the data in Table 1 also shows this lack of environmental awareness in the ME and potential to free up some energy for export.

3. NATURAL GAS EXPORT PROJECTS

The following is a description and analysis of the gas exporting nations Iran, Qatar, the UAE and Oman (in order of reserve amount) based on (a) an outline of the gas industry with a brief account of its history, (b) a look at the supply/demand balance, (c) a review of future export projects and (d) conclusions for the countries’ export potential. The focus is on Iran and Qatar as the countries with the highest natural gas reserves.

3.1 Iran

(a) Outline and history of the gas industry

The current situation of Iran’s gas sector can only be understood by looking at the history of the Iranian oil and gas industry.5 Commercial oil production by the Anglo-Persian Oil Company began in 1914. This company (subsequently renamed Anglo-Iranian Oil Company) remained the only operating company in Iran until 1951, when the government nationalized the oil industry and formed NIOC (National Iranian Oil Company).

Following the overthrow of the Mossadegh regime in 1953, a consortium of foreign oil companies was formed to operate in Iran. In addition, from the late 1950s until 1979, several major oil companies were active in Iran, operating under joint ventures with NIOC and consistently increasing oil production.

Drilling activity reached a peak in 1968, followed by record production levels in 1974.6 By 1979, most of Iran’s current offshore oil fields had been discovered. In the same year, exploration and appraisal activity as well as oil production collapsed in the wake of the Iranian Revolution and the Iran-Iraq War, which left the Iranian oil sector in dire need of fresh investment. Many facilities had been damaged in the war, and much of the existing infrastructure was ageing and needed replacement.

Exploration and appraisal drilling activity in Iran has never returned to its pre-1979 level, and the author sees only a low likelihood that it will do so in

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4. The United States and Germany are shown as comparisons for high and low energy intensities among OECD countries.
5. For details see Wood Mackenzie (2009a, p. 21).
6. For details see Wood Mackenzie (2009a, pp. 16–18).
the near future, given the limited funds available to NIOC and the small number of foreign oil companies operating in the country.

Until 1983, all gas produced in Iran was associated gas from the major oil fields. Gas production increased slowly but steadily through the 1980s thanks to the development of a number of onshore, non-associated gas fields. Gas production continued to grow through the remainder of the 1990s as capacity upgrades were implemented (BP 2010, p. 24). Today it is evident that Iranian gas production will increasingly be dominated by the development of the super-giant offshore South Pars gas field in the southern Gulf, which started production in early 2002. The structure extends into the Qatari sector, where it is known as the North Field. This joint gas reservoir is the single largest gas field in the world.

(b) Supply/demand balance

Despite Iran’s position as OPEC’s second largest oil exporter and the holder of the world’s second largest gas reserves, the country is surprisingly a net importer of natural gas. In a conversation with the author on June 22, 2010, National Iranian Gas Company (NIGC) Managing Director Mr Owji stated that Iran imports gas from Turkmenistan (8 bcm/a to be increased to 14 and later to 20 bcm/a) and will soon be importing gas also from Azerbaijan (5 bcm/a). It is exporting up to 10 bcm/a to Turkey as well as small volumes to Armenia. However, the current production of 131 bcm/a is just sufficient to meet its export obligations and the immense local demand (as illustrated in Figure 3).

Low energy prices (in 2008 Iranian domestic energy subsidies exceeded $80bn7) have caused efficiency levels in Iran’s energy sector to fall. This fact and the rapidly growing population—73 million in 2010—have resulted in a tremendous growth of energy consumption in recent years and huge inefficiencies. The demand peak in winter regularly leads to supply disruptions, resulting in the switch of power stations to liquid fuels. An analysis compiled by the author suggests that Iran’s gas consumption will grow by up to 6% p.a., which means it could double by 2020 compared to today’s level.

In February 2010, the Guardian Council finally approved a reform bill which was passed by the parliament in November 2009 and calls for subsidies to be gradually reduced over a five-year period and replaced by cash handouts to some sections of the population (BEDigest 2010, pp. 10, 15). The Petroleum Minister HE Mir-Kazemi plans energy price increases of up to 1000%, which—if he succeeds despite the risk of high inflation—would reign in energy consumption. However, the NIGC prediction that gas consumption would fall by 25% after the redirection of subsidies, seems overly optimistic (Atieh Bahar Consulting 2010a, p. 10).

Moreover, Iran has a significant and growing demand for gas in its oil fields because some of the gas needs to be re-injected to enhance the oil recovery

7. For details see Ghorban (2010, pp. 25–28).
factor (EOR). Iran already has the largest gas re-injection volumes in the ME (approx. 45 bcm/a), but by the middle of the next decade, it will probably require at least 100 bcm/a for re-injection (Fesharaki and Adibi 2009, p. 9).

Lovatt (2010, p. 4) alludes to another evidence of the wasteful use of energy, namely gas flaring. Globally, around 150 bcm/a of gas is flared, with Iran having the highest total at 10.3 bcm/a in 2008. These significant volumes are missing for indigenous demand and export.

(c) Future export projects

Iran’s energy experts are keen to make use of the immense gas reserves and pursue a number of LNG projects in order to catch up with their ME neighbors (Table 2).

Iran LNG had hoped to ship its first LNG in 2011 (Platts 2009, p. 5), which turned out to be overly optimistic. While marine facilities and LNG storage tanks are being built, there is little progress in the construction of liquefaction units. Hence, Iran will realistically not be able to export LNG before 2015.8

Iran also has bullish pipeline export plans to Europe, ME and Asia as shown in Figure 5.

Iran has started negotiations with potential European gas buyers and has already succeeded in signing a 25-year deal with the Swiss company EGL. However, NIGC and EGL still need to determine the base price. Another example is the Nabucco gas pipeline project, whose consortium members are eager to start talks with Iran. However, due to political reasons, Iran has so far not been invited to participate in the project, which is promoted by the EU as a way of reducing European dependence on Russian gas. The most recent step in these talks is an MoU signed between Turkey and Iran in October 2009 to broaden gas industry ties and especially to facilitate the efficient flow of gas through Turkey to Europe (BEDigest 2009, p. 1).

While all Gulf States except Qatar are suffering from gas shortages, Iran—despite its reserves—has failed to benefit from the situation. However, Iran itself predicts that by 2014 it will be exporting to Kuwait, Bahrain, the UAE and Oman:9

- Kuwait: Iran and Kuwait have been holding talks on the construction of a 570 km pipeline (of which 240 km would be subsea) to take Iranian gas to Kuwait. However, the two sides have yet to agree on the gas price and governing rules.
- Bahrain: There have been negotiations with Iran, according to which

8. Holz et al. (2009, p. 143) predict an export capacity of 24 bcm/a already by 2015. This seems very ambitious, taking into account the construction period of roughly 5 years for a liquefaction plant and political sanctions.
9. See Graham et al. (2010, p. 7); Omidvar (2010, p. 49) and Tehran Times (2010).
Table 2: Iranian LNG Export Projects

<table>
<thead>
<tr>
<th>Project</th>
<th>Volume</th>
<th>Status</th>
<th>Shareholders</th>
<th>Offtakers</th>
<th>Markets</th>
</tr>
</thead>
<tbody>
<tr>
<td>Iran LNG (2 trains)</td>
<td>10.6 mtpa</td>
<td>Under development (start 2015)</td>
<td>NIOC (49%), Pension Funds (51%), Chinese CNOOC (tbd), Indian ONGC (tbd)</td>
<td>Asian and European companies</td>
<td>Asia (China, India), Europe</td>
</tr>
<tr>
<td>Persian LNG</td>
<td>16.2 mtpa (2 trains)</td>
<td>Proposed (start 2017)</td>
<td>NIOC (50%), Shell (25%), Sinopecb (25%)</td>
<td>Shareholders and Asian companies</td>
<td>Asia (espec. China, Thailand, India)</td>
</tr>
<tr>
<td>Pars LNG</td>
<td>10 mtpa (2 trains)</td>
<td>Proposed (start 2017)</td>
<td>NIOC (50%), Total (40%), Petronas (10%), Chinese CNPC (tbd)</td>
<td>Shareholders from train 1, Asian companies from train 2</td>
<td>Europe, Asia (India, Thailand, China)</td>
</tr>
<tr>
<td>Golshan and Ferdowsi</td>
<td>10 mtpa (2 trains)</td>
<td>Speculative</td>
<td>Malaysian Pertofield (100%)</td>
<td>Malaysian SKS, NIOC</td>
<td>Malaysia, Europe</td>
</tr>
<tr>
<td>North Pars</td>
<td>20 mtpa</td>
<td>Speculative</td>
<td>MoUd with Chinese CNOOC</td>
<td>tbd</td>
<td>China</td>
</tr>
<tr>
<td>Qeshm LNG</td>
<td>3.5 mtpa</td>
<td>Speculative</td>
<td>HoAe with Australian LNG Ltd</td>
<td>tbd</td>
<td>India, East Africa</td>
</tr>
<tr>
<td>Lavan LNG</td>
<td>4 mtpa</td>
<td>Speculative</td>
<td>European company</td>
<td>European company</td>
<td>Europe</td>
</tr>
</tbody>
</table>


a Hui (2010, pp. 1, 7) explains the suspension of Persian LNG in August 2010 with commercial and political obstacles.
b Chinese Sinopec replaced Repsol in June 2010, after the latter had failed to commit to the project.
c Hui (2010, pp. 1, 7) explains the suspension of Pars LNG in August 2010 with commercial and political obstacles.
d Memorandum of Understanding
e Heads of Agreement

the Arab state is expected to import up to 10 bcm/a of gas over a 25-year period and to invest in Iran’s upstream business. The talks had been suspended following political tensions in February 2009, but Bahrain resumed negotiations in 2010.

- UAE: A negative example of the relationship between Iran and the UAE is the contract signed between NIOC and the UAE-based Crescent Petroleum Company, which resulted in arbitration proceedings in 2009 over unresolved disagreements about the gas price. A positive example, however, is an MoU announced in September 2009 between NIGEC (National Iranian Gas Export Company) and a foreign company aimed at exporting gas to the UAE over a 25-year period.
Oman: Given Oman’s LNG units and industries, it would be Iran’s prospective gas client in the region. However, a dispute over gas prices and national interests have stood in the way to finalize an agreement between the two countries (to be examined in more detail in section 3.4).

Iran has also plans to export piped gas to Pakistan and further to India (BEDigest 2010b, p. 3). Iranian and Pakistani officials agreed in March 2010 to complete a gas pipeline project (IPI / Peace Pipeline) by 2014 and signed the corresponding gas export deal in May 2010 - after 17 years of negotiations. India is a much larger and more lucrative market for Iran. However, India has allegedly been considering quitting the pipeline deal as negotiations over gas prices, transit fees and delivery point stalled, and political tensions between India and Pakistan worsened. Consequently, Iran and India started discussions on an offshore route through the Sea of Oman (bypassing Pakistan).

10. For details see Godier (2010a, p. 2).
(d) Conclusions for a prospective export potential

Despite Iran’s export plans and its potential of the world’s second largest gas reserves, the country is yet to develop an LNG business and step up pipeline exports while having to face the following challenges:11

- Geopolitical tensions (on 9 June 2010, the UN Security Council imposed a fourth round of sanctions against Iran) due to the ongoing disagreement between the UN and Iran over Iran’s uranium enrichment program have forced Western companies (e.g. Eni, Linde, Repsol, Shell, Siemens, Total) to distance themselves from their projects.
- US sanctions and EU legislation12 are preventing Western companies from participating in and providing technology for LNG projects.
- Iran’s current political problems make foreign investment a critical issue. According to the Iranian Petroleum Minister HE Mir-Kazemi (2009), “the upstream petroleum sector will require an annual investment of $35bn”. Projects of this magnitude will be difficult to fund without the involvement of internationally reputable banks.
- Given Iran’s constitution and its fiscal framework, foreign companies are unable to hold shares in Iran’s reserves or participate in upstream projects in the form of PSAs (production sharing agreements). The only available upstream project involvement for international companies are buy-back contracts. Brexendorff et al. (2009) describe in detail, how buy-back contracts are based upon a defined scope of work, a capital cost ceiling, a fixed remuneration fee and an agreed cost recovery period. They allow foreign companies to invest in projects, manage them in the development phase, recoup their costs and earn a fixed rate of return during the operation phase. Iranian managers have realized the disadvantages of these contracts and have therefore developed the third generation of buy-back contracts which will lower the investment risk for contractors and investors.

Epbali (2010, p. 7) draws the consequences of the challenges mentioned above: Several projects being undertaken by local Iranian companies are years behind schedule due largely to financial constraints and a lack of modern technology.

In recent years, Iran introduced numerous LNG projects aiming to supply 73 mtpa of new LNG over the new decade. Iran also has various MoUs for

12. Hall and Dourian (2010, p. 5) describe how the EU and its member states will go further with accompanying measures including restrictions on trade as well as the oil and gas industry. Vukanovic et al. (2010, p. 4) provide details for the EU sanctions.
pipeline deals in place. For the moment, however, Iran has prioritized domestic gas demand ahead of LNG and pipeline exports. Thus, the Iranian LNG business has slowed down, while neighboring Qatar has become the world’s largest supplier of LNG. Farrell (2010, p. 3) and Hui (2010, p. 7) describe the suspension of Persian LNG and Iran LNG and draw the conclusion that it will also be unlikely for Iran LNG (due to commercial and political obstacles) to materialize by the middle of the new decade. Further LNG export potential is even more speculative and can only be realized by 2020 if the problems of large domestic consumption, massive gas re-injection requirements and lack of access to capital are resolved. A general concern is Iran’s ability to adhere to project timetables, given the sanctions and diplomatic pressure being orchestrated from Washington as well as the domestic political fissures across much of Iran.

The pipeline projects are technically less complex and for short distances also feasible for smaller volumes. Consequently, pipeline projects within the ME region might materialize within the next years, whereas pipeline export projects to Europe are facing similar challenges as the LNG projects mentioned above.

An analysis of export projects has to be seen against the background of future political developments and hence Iran’s access to modern technology. An analysis undertaken by the author suggests that—under a scenario of continued sanctions and political confrontation with the West—Iran’s export potential will be limited to approximately 20 bcm/a by 2015 (including the volumes delivered to Turkey). Under a scenario of peaceful resolution of the standoff, Iran will have access to the international finance market (essential in particular for upstream development) and will be able to develop LNG projects, resulting in pipeline and LNG exports up to 35 bcm/a by the middle of the new decade and even more in the years beyond. If in addition the redirection of subsidies is really successful another 10 bcm/a could be made available for export.

NIOC executives suggest that it is incumbent upon Iran to move because it is extracting 60 bcm/a less gas from the South Pars/North Field than its neighbor Qatar and consequently loses revenue (approx. $20bn p.a.). However, the classic problem of drainage only exists if one party in a non-unitized field produces more than his share of the reserves. Since the North Field reserves are roughly twice those in South Pars, balanced production would have Qatar producing twice as much as Iran. It is important to note that Iran is currently producing more than its share would justify. If Iran is ultimately successful in developing its 22 South Pars blocks, its planned production would substantially drain reserves from Qatar’s much more modest development plans.

13. See calculation for that number in Atieh Bahar Consulting (2010b).
3.2 Qatar

(a) Outline and history of the gas industry

Gas has been produced in Qatar since 1949, when it was used in operations associated with oil production.14 Gas was also produced from the offshore fields when they came on stream in the early 1970s. Until 1978, most of this was flared and vented. In 1978, Qatar began to collect non-associated gas from the Khuff reservoir to meet growing domestic demand. Meanwhile, gas flaring was reduced to minimal levels, as Qatar sought to monetize the vast reserves of the giant North Field, which was discovered in 1971.

Until 1993, gas production had never exceeded 10 bcm/a. When the North Field was fully appraised and the extent of reserves established, development of the field was planned in stages. Local demand was to be met first, and delivery to Qatar’s first LNG plants followed at Ras Laffan in 1997.

(b) Supply/demand balance

Qatar’s two large LNG companies and Qatar Petroleum (QP) subsidiaries, Qatargas and RasGas, are involved in major LNG activities totaling some 60 mtpa of LNG (see Table 3) for deliveries to the US, Asia or Europe.

In addition, Qatar supplies the UAE with pipeline gas via the Dolphin project, which involves the production and processing of natural gas from the North Field. The project became necessary after gas consumption in the UAE threatened to outpace supply. Transportation of dry gas by subsea export pipeline to the UAE started in July 2007 and was extended to Oman in October 2008.15

Gas consumption in Qatar has more than doubled within the last decade (BP 2010, p. 27), and the author predicts that it will increase further. A fair assumption is that the current domestic consumption of 21 bcm/a will increase by 60–70% to total between 32 and 36 bcm/a in 2020. There are several reasons for this immense growth: First, Qatar, one of the richest nations in the world, has an incredibly high energy intensity (as illustrated in Table 1). Second, much of the consumption is associated with gas industry activities like liquefaction fuel and GTL16 thermal efficiency losses. Fortunately, the large reserve basis combined with the low population of just over one million leaves the Qatari Emir with sufficient gas for even more lucrative pipeline and especially LNG exports.

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14. For details regarding the history of Qatar’s gas industry see Wood Mackenzie (2010a, pp. 21–24).

15. Mubadala Development Company owns 51% of Dolphin Energy on behalf of the government of Abu Dhabi, while Total of France and Occidental Petroleum of the US each hold a 24.5% stake (King 2010, p. 4). Long-term (25 years, partly interruptible) customers for Dolphin gas are Abu Dhabi Water and the Electricity Authority (ADWEA), the Dubai Supply Authority (DUSUP) as well as after an extension of the pipeline the Oman Oil Company from October 2008.

16. As part of QP’s ongoing efforts to realise value from its huge gas reserves, it had developed a series of options and agreements for construction of GTL (Gas-to-Liquids) plants. Only two GTL
Table 3: Qatari LNG Supply Joint Ventures

<table>
<thead>
<tr>
<th>Project</th>
<th>Volume</th>
<th>Status</th>
<th>Shareholders</th>
<th>Offtakers</th>
<th>Destinations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Qatargas 1</td>
<td>9.7 mtpa (train 1 + 2 + 3)</td>
<td>Start 1996</td>
<td>QP (65%), ExxonMobil (10%), Total (10%), Marubeni (7.5%), Mitsui (7.5%)</td>
<td>Chubu Electric, Japanese Consortium, Gas Natural</td>
<td>Japan, Spain</td>
</tr>
<tr>
<td>RasGas 1</td>
<td>6.6 mtpa (train 1 + 2)</td>
<td>Start 1999/2000</td>
<td>QP (63%), ExxonMobil (25%), KORAS (5%), Itochu (4%), LNG Japan (3%)</td>
<td>KOGAS, Petronet, CPC, Eni/ Iberdrola</td>
<td>South Korea, India, Spain, Portugal</td>
</tr>
<tr>
<td>RasGas 2</td>
<td>14.1 mtpa (train 3 + 4 + 5)</td>
<td>Start 2004/2007</td>
<td>QP (68.8%), ExxonMobil (29.5%), Taiwan CPC (1.7%)</td>
<td>Petronet, CPC, ExxonMobil, Edison, Distrigaz, EdF, Endesa</td>
<td>India, Taiwan, Europe (Italy, Belgium, Spain)</td>
</tr>
<tr>
<td>Qatargas 2</td>
<td>15.6 mtpa (train 4 + 5)</td>
<td>Start 2009</td>
<td>Train 4: QP (70%), ExxonMobil (30%) Train 5: QP (65%), ExxonMobil (18.3%), Total (16.7%)</td>
<td>ExxonMobil, Total, Chubu Electric, CNOOC</td>
<td>UK, US, France, Mexico Japan, China</td>
</tr>
<tr>
<td>RasGas 3</td>
<td>15.6 mtpa (train 6 + 7)</td>
<td>Start 2009/2010</td>
<td>QP (70%), ExxonMobil (30%)</td>
<td>ExxonMobil, KOGAS, CPC, Petronet, KNPC (in summer)</td>
<td>US, South Korea, Taiwan, India, Kuwait (in summer)</td>
</tr>
</tbody>
</table>


In September 2005, KORAS exercised an option to acquire 5% of the project which is owned by KOGAS (60%), Samsung Corp. (10%), Hyundai Corp. (8%), SK Corp. (8%), LG International Corp. (5.6%), Daesung Industrial Company (5.4%) and Hanwha Corp. (3%).

(c) Future export projects

Qatargas and RasGas have already committed themselves to future LNG projects which are under construction. After completing the projects listed in Table 4, Qatar will supply about 77 mtpa of LNG to the world markets.
Table 4: Qatari LNG Export Projects

<table>
<thead>
<tr>
<th>Project</th>
<th>Volume</th>
<th>Status</th>
<th>Shareholders</th>
<th>Offtakers</th>
<th>Destinations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Qatargas 3</td>
<td>7.8 mtpa (train 6)</td>
<td>Under construction (start 2010)</td>
<td>QP (68.5%), ConocoPhillips (30%), Mitsui (1.5%)</td>
<td>ConocoPhillips, CNOOC, PTT, Repsol</td>
<td>US, China, Thailand, Canada</td>
</tr>
<tr>
<td>Qatargas 4</td>
<td>7.8 mtpa (train 7)</td>
<td>Under construction (start 2010)</td>
<td>QP (70%), Shell (30%)&lt;sup&gt;a&lt;/sup&gt;</td>
<td>Shell, PetroChina, Dusup (in summer)</td>
<td>USA, China, Dubai (in summer)</td>
</tr>
</tbody>
</table>


<sup>a</sup> Marubeni has option to buy stake.

Chinese and Indian companies in particular are currently looking to increase their offtake. In addition, probably all European current and future LNG importers as well as new Asian players are in discussions with RasGas and/or Qatargas. Some initiatives are public:

- Turkey and Qatar signed an agreement in August 2009 to potentially cooperate on a number of proposed oil and gas projects in order to reduce Turkey’s dependence on relatively expensive spot LNG contracts during winter. Turkey seeks an LNG deal of approximately 3 mtpa for 15–25 years (O’Byrne 2010, p. 5 and Al Harthy 2009).
- Pakistan is looking to import LNG from Qatar to cope with an intensifying energy crisis that is crippling the country’s economy. The government plans to use 1.5 mtpa of imported LNG to fuel power plants and produce electricity to meet part of a 4 GW supply deficit (Argus 2009, p. 16).
- Bangladesh plans to import 3.5 mtpa of LNG from Qatar using floating storage and regasification units to ease an ongoing energy crisis (Rahman 2010, p. 3).
- In November 2008, Poland invited Qatar as a partner in their regasification terminal project in the Baltic Sea (Swinoujscie, commissioning plans for 2014). Poland targets to source 2 mtpa, later 4 mtpa of LNG, and signed an MoU with Qatargas over 1.5 mtpa in June 2009 (Easton 2010, p. 2).

While Qatari Energy Minister HE Al-Attiyah ruled out increasing pipeline supplies in 2008, a global LNG glut has pushed Qatar to open talks on increasing gas sales via pipeline to other ME countries, to Turkey and to Pakistan (Figure 6).

The most interesting activity involves Qatar and Turkey because the above agreement between these two countries also considers Qatar as a potential source of 5–7 bcm/a of gas for the proposed Nabucco pipeline. Turkey’s geo-
strategic role as a bridge between the energy reserves in the ME and the energy consuming countries in Europe places it in a favorable position. The 3,000-km Qatar-Turkey pipeline project would require support from key regional states (i.e. Saudi Arabia, Jordan and Syria) and would also offer these transit countries guaranteed supplies. Historically, such a project was always complicated by Saudi Arabia’s relationship with Qatar. However, since joining the WTO, Saudi Arabia is under an obligation to allow the unhindered passage of pipelines.

(d) Conclusions for a prospective export potential

With the continuing expansion of these LNG and pipeline projects (in addition to local supply and GTL projects), gas production in Qatar will continue to rise rapidly at least until 2013. However, the award of any new gas-based projects is contingent on the results of an ongoing North Field reservoir study, which is not expected to be completed before 2014/15. Until then, a moratorium is in place in order to achieve a production rate of 250 bcm/a over a period of 100 years.\(^\text{17}\)

Qatar’s major LNG trains could generate significant extra output (Dourian and Rushforth 2009, p. 3). HE Al-Attiyah (2009) stated that “there is enough

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\(^{17}\) Qatar Petroleum wants to maximize the long-term benefits from the resource and will only be able to do this by monitoring reservoir response once all current projects are onstream at peak production.
gas, with revamp and debottlenecking—we can produce an additional 12 mtpa”. This capacity increase would be prioritized over new grassroots export projects and could be done very quickly, once the above moratorium on new projects is lifted (Latta 2010, p. 5). However, there is no need to do so before 2014, since it is doubtful whether the market can absorb this rapid growth of LNG within the coming years. Moreover, Qatar has no urgent need for additional revenues, since it already has the world’s highest GDP per capita ($92,000).

Fesharaki et al. (2009) describe the dramatic change in market conditions resulting from the economic downturn and the expansion of the US unconventional gas production, particularly shale gas. Consequently, Qatar plans to divert 12–20 mtpa away from the US market. Qatar is faced with a supply bubble and competition from new Australian export projects, and hence will wait for these new supplies to balance out with increasing demand before taking final investment decisions on new projects.

All in all, Qatar has achieved a lot by developing into the largest LNG exporter in the world. It seems that it will favor new LNG over new pipeline exports. However, the moratorium on new LNG projects is likely to remain in place until at least 2014 when it could be lifted using a de-bottlenecking approach. Qatar’s potential lies mainly in the second half of the new decade in which it could produce additional 20–30 bcm/a for export.

3.3 United Arab Emirates (UAE)

(a) Outline and history of the gas industry

Abu Dhabi is the main reserve holder among the seven UAE emirates; it comprises around 90% of total UAE sales gas production and considerably more when EOR is considered. Most of the gas reserves are to be found in the deeper horizons below the known oil reservoirs. This gas is mainly non-associated and partly sour gas.18

The first concession rights in Abu Dhabi were awarded in 1939. Drilling activities, which started in the 1950s, show a peak in 1984. Commercially, the 1960s and 1970s were the most successful period. This success declined markedly in the late 1980s and 1990s. Today, gas from the onshore Abu Dhabi fields is sent to domestic power stations and industrial users and is used for re-injection and operations (Wood Mackenzie 2009b, p. 10–23).

Following the discovery of Abu Dhabi’s giant oil fields in the 1950s and 1960s, it was the high levels of gas flaring and the advent of LNG technology in the early 1970s that led to the construction of the first LNG plant.

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18. Sour gas is natural gas or any other gas containing significant amounts of hydrogen sulfide (H₂S).
Table 5: UAE LNG Supply Joint Ventures

<table>
<thead>
<tr>
<th>Project</th>
<th>Volume</th>
<th>Status</th>
<th>Shareholders</th>
<th>Offtakers</th>
<th>Destinations</th>
</tr>
</thead>
<tbody>
<tr>
<td>ADGAS (Abu Dhabi Gas Liquefaction Co.)</td>
<td>5.8 mtpa (train 1 + 2 + 3)</td>
<td>Start 1977/1994</td>
<td>ADNOC (70%), Mitsui (15%), BP (10%), Total (5%)</td>
<td>TEPCO</td>
<td>Japan</td>
</tr>
</tbody>
</table>

Sources: Platts (2010, pp. 17–18), Wood Mackenzie (2009c, pp. 1–6)

* Abu Dhabi National Oil Company

(b) Supply/demand balance

The LNG plant at Das Island (Table 5) is the center of the offshore gas infrastructure. It has been operational since 1977, producing and exporting LNG primarily to Japan. The original two-train facility was expanded to include a 3-mtpa train, which came on stream in 1994.

While the Japanese company TEPCO is the primary purchaser of the project’s LNG, shorter-term sales agreements have also been signed with other companies (e.g. Gazprom, BP). In addition, ADGAS has been a regular seller of spare LNG cargoes on the spot market. However, weak global gas market and high UAE domestic demand will mean that from 2009 to 2011 ADGAS will be producing at below its capacity.

In 2009 domestic consumption was 59 bcm, which includes 18 bcm for re-injection (as illustrated in Figure 3); the author predicts the local demand to increase until 2020 to above 100 bcm/a (+ 8%/a). The main reason for this is the annual peak demand for electricity, which is expected to increase from 18.5 GW in 2008 to 35 GW by 2020. Bains (2009, 28) estimates that the volumes of natural gas available for the electricity sector in 2020 will only be able to generate 20–25 GW. The gap will be filled by four nuclear power plants producing between 4 and 5.5 GW by 2020 because the burning of liquids or coal would pose a threat to the environment. Abu Dhabi already selected a site for the first plant in Braka 75 km from the Saudi border and filed an environmental assessment as well as two license applications with the intention to be operational with 1.4 GW by 2017 (Namatalla 2010, 1).

Like Iran and especially Qatar, the UAE is an example of inefficient energy use (as illustrated in Table 1). The high energy intensity demonstrates that there is room for reducing the predicted growth in consumption.

(c) Future export projects

Abu Dhabi has been undergoing various discussions on future LNG projects and supplies. However, these talks have not turned into firm agreements because indigenous production would have to be significantly increased to free up volumes.
As a result, Abu Dhabi provided field development opportunities, and in 2006 launched the single largest non-associated gas project ever seen in the UAE dealing with the production of sour gas. In July 2008, ADNOC and ConocoPhillips signed an agreement suggesting a joint operating company to be the first to develop Abu Dhabi’s enormous sour gas reserves. Dutta (2009, p. 4) elaborates on a $10bn-plus investment be required to produce up to 10 bcm/a of sour gas from the deep onshore Shah reservoir to deliver up to 6 bcm/a of sales gas for the domestic market and significant volumes of condensate and NGLs for export. Ironically, ConocoPhillips quit its involvement in the project in April 2010 which will certainly cause project delays. However, industry observers believe that ADNOC (which has limited non-associated and/or high sulfur gas experience) will bring in a new foreign company, e.g. Shell, Occidental or Total (MEES 2010, p. 23).

In addition, National Petroleum Construction Company (NPCC) was awarded a $400m EPC contract in June 2009, which involves the offshore portion of increasing gas production by drilling additional gas wells.

(d) Conclusions for a prospective export potential

There is uncertainty surrounding ADGAS’s production post-2019, once its contract with TEPCO expires. Whether the project’s LNG production continues will primarily depend on the availability of gas given the UAE’s competing demand for gas. However, due to the significant remaining gas reserves in the UAE, ADGAS is expected to continue and perhaps slightly increase LNG production post-2019.

There have been discussions on debottlenecking trains 1, 2 and 3 to increase LNG exports, and the question of whether refurbishing existing trains or building larger-capacity trains would improve plant performance has also been looked into.

3.4 Oman

(a) Outline and history of the gas industry

In 1937, Petroleum Concessions Limited signed a 75-year option with the government of Oman, which was converted into a concession agreement in 1942. From 1951, the company has been known as PDO (Petroleum Development Oman), a partnership between the Omani Government (60%), Shell (34%), Total (4%) and Partex (2%). Since the 1950s, PDO has dominated E&P activity in the country.

19. Natural Gas Liquids
20. Engineering, Procurement & Construction
Table 6: Omani LNG Supply Joint Ventures

<table>
<thead>
<tr>
<th>Project</th>
<th>Volume</th>
<th>Status</th>
<th>Shareholders</th>
<th>Offtakers</th>
<th>Destinations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oman LNG</td>
<td>7.4 mtpa</td>
<td>Start 2000</td>
<td>Government (51%), Shell (30%), Total (5.54%), Korea LNG (5%), Mitsubishi (2.77%), Mitsui (2.77%), Partex (2%), Itochu (0.92%)</td>
<td>KOGAS, Osaka Gas, BP, Itochu</td>
<td>Korea, Japan</td>
</tr>
<tr>
<td>Qalhat LNG</td>
<td>3.7 mtpa</td>
<td>Start 2005</td>
<td>Government (46.8%), Oman LNG (36.8%), Union Fenosa (7.4%), Itochu (3%), Mitsubishi (3%), Osaka Gas (3%)</td>
<td>Union Fenosa, Itochu, Mitsubishi, Osaka Gas</td>
<td>Spain, Japan</td>
</tr>
</tbody>
</table>

Sources: Platts (2010, p. 13), Wood Mackenzie (2010b, pp. 1–6), Wood Mackenzie (2010b, pp. 1–4)

Drilling activities in Oman were highest between 1980 and 2000 with an average commercial success rate of about 10% in these two decades.

(b) Supply/demand balance

There are two LNG projects under operation: Oman LNG and Qalhat LNG (see Table 6). Although they have a different equity structure, both are operated by Oman LNG and share storage and loading facilities.

In addition to the above long-term contracts, Oman LNG has been selling volumes on a short-term basis, e.g. to GdF Suez, Total, KOGAS, BP and Shell.

Oman’s natural gas production in 2009 was 24.8 bcm (BP 2010, p. 24). The EIA (2009b) evaluates the proven reserve base as limited, but expects more gas to be discovered. Consequently, Oil&Gas (2010, 32) believes that production volumes could reach 34 bcm in 2013.

Oman is one of the most stable countries in the ME with a real GDP growth of 6.4% (CIA 2010), which leads to a vast expansion of the energy markets. Roughly two-thirds of Oman’s total energy consumption already comes from natural gas and the remainder from oil. Its future domestic energy consumption plans call for an even increased use of natural gas in energy generation in order to free up more oil for export. Demand for gas in Oman is forecast to rise even further due to expansion of the power, desalination and petrochemicals industries together with demand in EOR projects.

22. The power market alone is expected by the author to grow from 2.6 GW to 4.2 GW of installed capacity by 2015. This rise is based on a mix of CCGT (Combined Cycle Gas Turbine) and coal-fired plants.
Omani gas consumption in 2009 is estimated at 15 bcm/a of natural gas, almost 25% more than 2007 consumption levels. EIA (2009b) estimates that by 2013 consumption could reach 16.5 bcm/a, and by 2020 more than 20 bcm/a.

In an attempt to meet that demand, Oman has been importing gas via Qatar from the Dolphin pipeline since October 2008, and PDO plans to bring a further seven gas fields on stream over the next five years. This action was precipitated by falling oil production from PDO concessions together with an emerging supply/demand gap in the Omani gas market.

However, the author thinks that PDO will be unable to meet Oman’s gas demand alone, and will require assistance from other operators, since indigenous future gas is expected to be found in tight and/or very deep gas reservoirs. Over the past years, Oman has sought to attract gas-focused international oil companies in order to produce gas from the more technically challenging and geographically complex fields. After BG just walked away from its tight gas field development, having failed to find sufficient recoverable reserves and condensate to justify the $800mn-1bn investment needed, the government is now relying on the likes of BP and Occidental supplying significant volumes of gas from their respective projects in the future. If successfully appraised and developed, these projects have the potential to double Oman’s current gas sales production in a relatively short period of time, and ensure the government can continue to meet the country’s gas demand and export obligations for the foreseeable future as well as diversify the economy away from oil.

(c) Future export projects

Feedgas, EOR and growing domestic gas demand issues are preventing the Omani government from increasing exports, i.e. the LNG plants were only utilized at approximately 80% of their capacity in 2009 (Buckley 2010). From 2010 onwards, Oman LNG is forecast to produce only enough LNG to meet its contractual commitments, despite having an additional 1.8 mtpa nameplate capacity available. This is because feedgas originally earmarked for LNG is to be diverted to meet increased demand from Oman’s gas-fired industries and oil-field operations. Barber (2009, p. 3), however, elucidates that this has not been too much of a problem since some of the Omani customers have indicated that they would stay below their minimum-pay levels and make use of their make-up rights.

(d) Conclusions for a prospective export potential

Oman would be able to increase its export potential by meeting its indigenous demand at least partly by imports. Iran seems to be the only country in the region that is willing to (increase) export gas to Oman, whereas Qatar and the UAE have earmarked their present and future production for LNG or internal

23. Based on analysis undertaken by the author.
use. In 2008, Iran and Oman signed a framework agreement for the development of the Kish gas field and the construction of the necessary infrastructure for exports to Oman. Under the terms of this agreement, Oman will fully fund field development, which would produce up to 30 bcm/a of gas as of 2013, 10 bcm/a of which are dedicated for Oman and 20 bcm/a for Iranian domestic use. However, Omidvar (2010, p. 51) describes key challenges ahead, first and foremost gas pricing and establishment of an Iranian-Omani joint company.

All in all, the author predicts that Oman will not export gas with further LNG commitments until its domestic and feedstock positions are clearer. The announcement of Oman LNG and Qalhat LNG not to offer spot cargoes at least until 2012 because of burgeoning domestic demand was a clear indication in that direction (Buckley 2010).

However, Oman is engaging in a number of different activities to address its gas supply issues, including development of unconventional tight gas reserves, for which a special technology has to be used. The cost of future supplies becomes an issue here and will probably be higher than the currently (in global terms) relatively low breakeven FOB prices (post tax, without liquids) between 1.7 and 2.2 $/mmBtu.24

If Oman is successful in these E&P initiatives, additional LNG might become available for export from 2015 onwards, resulting in exports of about 15 bcm/a.

4. CONCLUSION

As the above discussion has demonstrated, there is potential for even increasing gas exports from the ME, but the countries have to overcome some obstacles: Iran has to improve its energy efficiency and solve the nuclear/political issue, Qatar needs to be clear about its reservoir dynamics and lift the moratorium, Abu Dhabi and Oman face technically challenging reserve structures on the E&P side. Moreover, most of projects where construction has not yet started are being postponed to prevent them from adding to the gas bubble predicted for the coming years.

What all these countries have in common is high domestic consumption combined with high energy intensity. In order to free up more volumes for export, it is crucial to increase awareness for energy conservation, especially by putting an end to the enormous subsidization of local energy prices, which in turn could create incentives to boost more expensive E&P projects in the region.

If these challenges are solved, the four countries mentioned could contribute to global LNG and pipeline gas supplies with additional volumes of 55 to 90 bcm/a in the period 2015 to 2020. The IEA (2009, p. 89) underlines such a forecast by predicting that the largest production increase on a global scale would

24. Thorough analysis of FOB (free on board) breakeven prices for Oman LNG and Qalhat LNG is done in Wood Mackenzie (2010b, 7) and Wood Mackenzie (2010c, 7).
come from the ME, which is expected to more than double output to close to 800 bcm in 2030 from an estimated 379 bcm in 2008.

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