ECONOMIC
CONSULTING
ASSOCIATES

Exploring the potential for electricity trade and interconnection among Yemen, and GCC countries

Draft Final Report

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Economic Consulting Associates

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Abbreviations

ADWEA	Abu Dhabi Water and Electricity Authority
ADWEC	Abu Dhabi Water and Electricity Company
ADDC	Abu Dhabi Distribution Company
AED	UAE dirham (UAE)
bbl	barrel
BCM	Billion cubic meters
BMI	Business Monitor International
BOO	Build Own Operate
BP	British Petroleum
BST	Bulk Supply Tariff
CAGR	Compound Annual Growth Rate
COA	Central Operating Area (Saudi Arabia)
DEWA	Dubai Electricity and Water Authority
EOA	Eastern Operating Area (Saudi Arabia)
ECA	Economic Consulting Associates
ECRA	Electricity and cogeneration regulatory authority (Saudi Arabia)
EGS	Eastern Gas Company (Saudi Arabia)
EIA	Energy Information Administration (USA)
FEWA	Federal Electricity and Water Authority (UAE)
GCC	Gulf Cooperation Council
GGFR	Global Gas Flaring Reduction partnership
GPIC	Gulf Petrochemical Industries Company (Bahrain)
GTL	Gas to Liquids
IEA	International Energy Agency
IPP	Independent Power Producer
IWPP	Independent Water and Power Producer
KNPC	Kuwait National Petroleum Company
KOC	Kuwait Oil Company
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MCM	Million cubic metres
MENA	Middle East and North Africa
MGS	Master Gas System (Saudi Arabia)
MIGD	Million Gallons per Day
MIS	Main Interconnected System (Oman)

mmbtu	million btu
MW	Mega watt
MWh	Megawatt hour
NGL	Natural gas liquids
OGC	Oman Gas Company
OPEC	Organization of the Petroleum Exporting Countries
OPWP	Oman Power and Water Procurement Company
PDO	Petroleum Development Oman
PEC	Provincial Electricity Corporation (Yemen)
QEWC	Qatar Electricity and Water Company
RAEC	Rural Areas Electricity Company (Oman)
RSB	Regulation and Supervision Bureau of Abu Dhabi (electricity and water)
SADAF	Saudi Petrochemical Company
SEC	Saudi Electricity Company
SEWA	Sharjah Electricity and Water Authority
SOA	Southern Operating Area (Saudi Arabia)
SWCC	Saline Water Conversion Corporation (Saudi Arabia)
TCM	Trillion Cubic Meters
TRANSCO	Abu Dhabi Transmission and Despatch Company
UAE	United Arab Emirates
USD	United States dollar
WEC	Water and Electricity Company (Saudi Arabia)
WOA	Western Operating Area (Saudi Arabia)
WTO	World Trade Organisation

Currency equivalents

(Exchange rates as of May 2009)

USD 1.00 = 0.286 Kuwaiti Dinar (KWD)

USD 1.00 = 3.74 Saudi Arabian Riyals (SAR)

USD 1.00 = 0.377 Bahrain Dinar (BhD)

USD 1.00 = 3.64 Qatari Riyals (QAR)

USD 1.00 = 3.67 United Arab Emirates Dirhams (AED)

USD 1.00 = 0.384 Omani Rial (RO), 1 Omani Rial (RO)

USD 1.00 = 199 Yemeni Rials (YR)

Conversion factors

1 (standard) cubic feet (scf) of gas = 0.028 cubic metres

1 metric tonne = 1.2023 short tonnes

1 kilolitre = 6.2898 barrels = 1 cubic metre

1 British thermal unit = 1.055 kilojoule (kJ)

1 trillion British thermal units = 0.028 BCM

1 tonne of oil equivalent (Toe) = 10 GJ

1 gallon = 0.0038 cubic metres

1 cubic meter = 1,000 litres

Executive summary

To be re-inserted XX Separate for the moment.

1 Introduction

This Report has been prepared by Economic Consulting Associates (ECA) under contract to the World Bank to explore the potential for interconnection and electricity trade among Yemen and the countries of the Gulf Cooperation Council (GCC).

1.1 Scope of the study

The primary objective for this study is to identify the efficient scenarios to utilise gas and electricity resources through cross-border integration among Yemen and the GCC countries[1]. The analysis includes an assessment of gas resources available for the electricity systems and identification of the potential for cross-border interconnections and integration among the respective countries to identify efficient ways to utilise the gas resources and generation capacities from national and regional perspectives.

Task 1 of the project involved the compilation of information on each of the six countries and an assessment of that information preparatory to using it in Task 2. Task 1 involved gathering:

- ❑ latest electricity demand projections;
- ❑ power generation capacity – current capacity, committed capacity (under development), and planned retirements – including information on available (MW) capacity, fuel type, technology, dual-fuel capabilities, age and efficiency;
- ❑ power sector investment plans for generation and transmission including, if available, information on investment options that were rejected (but could become feasible if cross-border trade occurs);
- ❑ projections of natural gas demand for the power sector;
- ❑ data on system load patterns;
- ❑ data on proven reserves of natural gas and existing or planned gas transmission developments and planned exploitation of gas resources in power generation and for other purposes;
- ❑ information on existing or proposed pricing policies for natural gas, power and other fuels;

[1] The possibilities of trade between the GCC group and Yemen with countries outside this grouping (eg., Djibouti) is specifically excluded from the study.

- ❑ review of policies and legal or regulatory frameworks impacting on the development and exploitation of power or gas resources domestically or for cross-border trade.

The information was collected through e-mail and telephone communication from relevant sources in each of the countries.

Task 2 involved the evaluation of potential cross-border/regional electricity trade and includes:

- ❑ assessment of possible scenarios to efficiently utilize natural gas in power generation;
- ❑ examination of cost-effective solutions to secure energy supply through power exchange and efficient generation mix;
- ❑ assessment of the relative economic benefits of gas cross-border trade versus electricity cross-border trade;
- ❑ evaluation of relevant electricity networks integration plans and ongoing projects;
- ❑ creation a feasible scenario(s) that promote regional network integration and cross-border electricity (and/or gas if feasible) trading among the respective countries to reliably meet their demand forecasts;
- ❑ articulate potential business development opportunities and economic benefits in the area of regional and/or cross-regional integration (institutional and investments).

In our Proposal we noted the limited budget for this project and the necessity of using simplified approaches to analyse the potential for cross-border trade. We also noted the limited resources available for data collection for Task 1. We note that considerably greater effort had to be expended on Task 1 in order to collect data requested in the Terms of Reference.

1.2 Location of the six GCC countries and Yemen

An overview map showing the location of the six countries and Yemen is provided in Figure 1.

Figure 1 GCC countries

Source: www.gcccountries-business.com

1.3 Outline of the Report

In Section 2 we describe information collected during Task 1 relating to the existing regional power and gas interconnection projects and, in Sections 3 to 9, we provide the information requested in the Terms of Reference relating to each of the seven GCC countries (Kuwait, Saudi Arabia, Bahrain, Qatar, UAE and Oman) and Yemen. Each of these Sections follows a similar structure.

Section 10 then describes the opportunities for trade in electricity and natural gas within the GCC countries. Section 11 describes the opportunities for trade between Saudi Arabia and Yemen and, finally, Section 12 describes the opportunities for trade between Oman and Yemen. Section 13 summarises the likely benefits of closer regional integration of the electricity and gas networks, describes the steps necessary to verify those benefits and notes some preconditions for achieving the benefits.

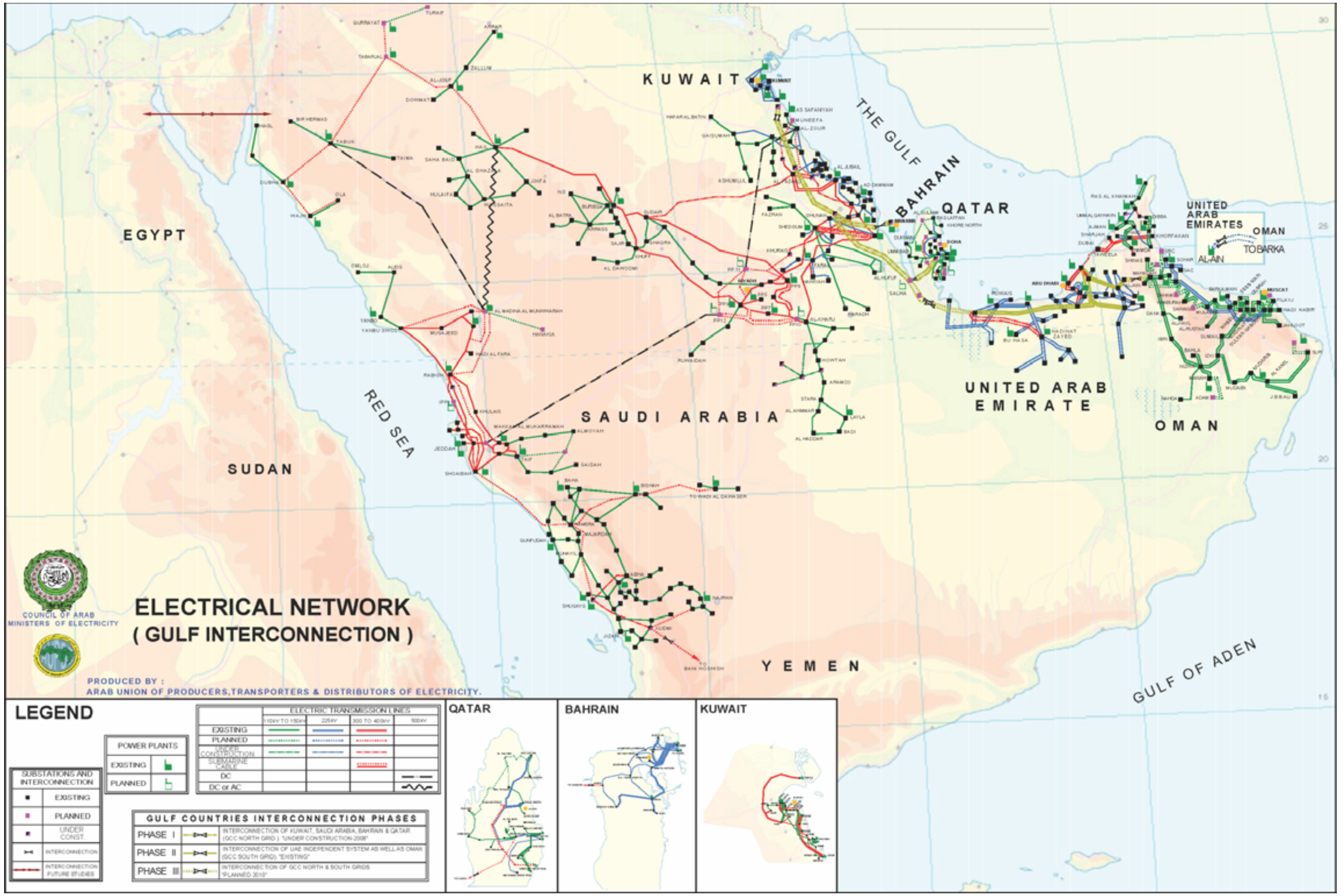
2 Regional GCC electricity and gas projects

Major gas pipeline and electricity interconnection projects are underway in the GCC countries. These are summarised below.

2.1 GCC electricity interconnection project

The GCC regional power grid shown in Figure 2 will allow electricity exchange among the six member states – Kuwait, Saudi Arabia, Bahrain, Qatar, United Arab Emirates (UAE) and Oman. Aimed at sharing reserve capacity and improving electricity supply reliability, the network is intended to reduce the need for investment in new generation.

Figure 2 GCC electricity interconnection scheme



Source: Arab Union of Producers, Transporters and Distributors of Electricity

The GCC interconnection project is divided into three phases (see Figure 3):

- In **Phase I**, the power grids of the northern states of Kuwait, Saudi Arabia, Bahrain and Qatar are being interconnected to form the GCC North Grid. The grid is expected to become fully operational in the first quarter of 2009.

  Phase I included the construction of a 400 kV grid in Kuwait, Saudi Arabia and Qatar with a 400 kV submarine cable link to Bahrain. It also includes a 380 kV, 60 Hz back-to-back HVDC transmission line to connect the 60 Hz Saudi Arabian with the other GCC countries which operate a 50 Hz system.

- **Phase II** of the project comprised:

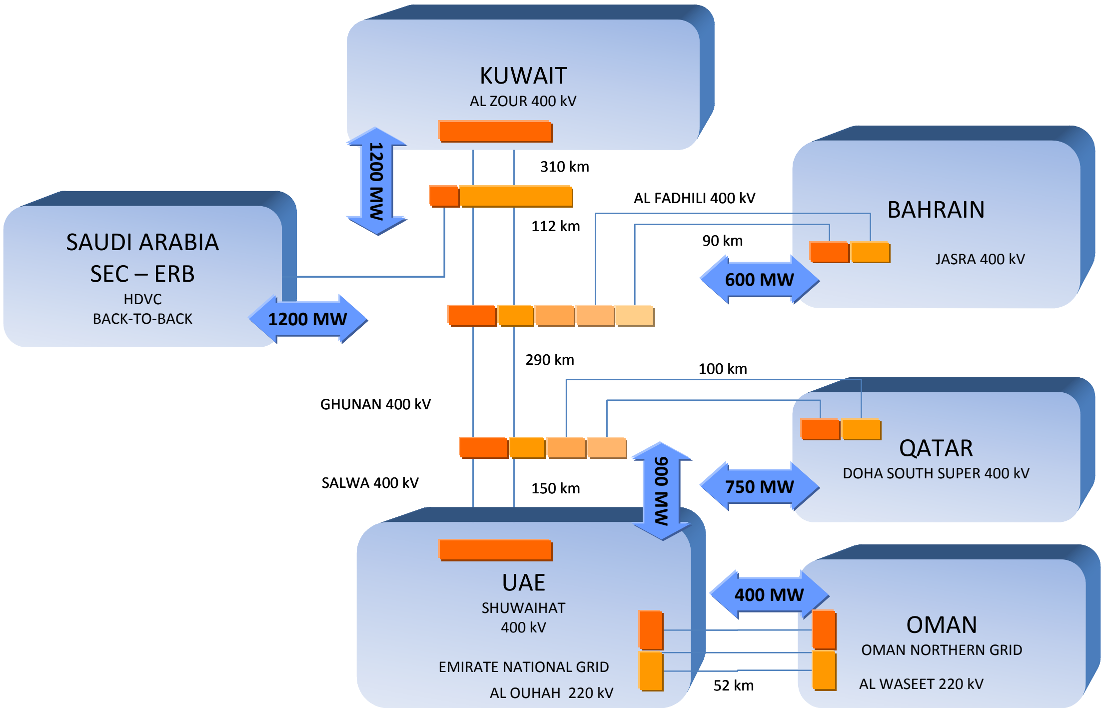
  - The integration of isolated networks of the various emirates of the UAE into a national grid. The UAE interconnected the separate power grids of its seven emirates to form the Emirates National Grid (ENG). Four major contact points have been established under the four power authorities in the UAE – Abu Dhabi Water and Electricity Authority (ADWEA), Dubai Electricity and Water Authority (DEWA), Sharjah Electricity and Water Authority (SEWA) and the Federal Electricity and Water Authority (FEWA), which is responsible for the other four northern emirates of Ajman, Umm Al Qaiwain, Fujairah and Ras Al Khaimah; and

  - Creation of Oman's integrated northern grid.

  This combined system (above) is the GCC South Grid. The UAE and Oman had signed an agreement to interconnect their electricity networks in 2004. This interconnection was completed in 2006 through a 220 kV line between Al-Waseet in Oman and Al-Ain in the UAE.

- In **Phase III**, the GCC North Grid will be interconnected with the South Grid. This is expected to be complete in 2010-11. Phase III includes a double-circuit 400 kV line from Salwa to Shuwaihat (UAE); and a double and a single-circuit 220 kV, 50 Hz line from Al Ouhah (UAE) to Al Waseet (Oman).

Figure 3 GCC electricity interconnection phases



Source: www.gccia.com.sa

A regional grid operator, GCC Interconnection Authority (GCCIA), based in Dammam, Saudi Arabia, has been set up to manage the interconnected system.

When completed GCC Interconnection will allow for imports of 1,200 MW from/to Kuwait and Saudi Arabia and between 600 MW and 900 MW from/to Bahrain, Qatar and UAE – as shown in Figure 3. The import/export capacity of the connection to Oman will be 400 MW.

The rules governing the operation of the regional grid – the Power Exchange Trading Agreement – are currently under negotiation among members.

2.2 GCC gas interconnection project

The GCC gas pipeline project, to export natural gas from Qatar to the UAE, Bahrain, and Kuwait, includes the following components[2]:

- The 48", 364 km Dolphin Gas pipeline shown in Figure 4 is used to export natural gas from the Qatar North Field to the UAE, began to deliver gas to Abu Dhabi in July 2007. The pipeline will initially carry 20 BCM of gas per year (57 MCM/day) but has the theoretical capacity to carry 32 BCM per year (90 MCM/day).

[2] The future of the planned Qatar-Bahrain and Qatar-Bahrain- Kuwait pipelines is uncertain due to the temporary moratorium imposed by Qatar on the expansion of gas extraction from its North field.

- Qatar-Bahrain pipeline, which will be used to export natural gas from Qatar to Bahrain but has been postponed following Qatar's moratorium on further export projects – revised dates have not been announced.

- Qatar-Bahrain-Kuwait pipeline, which will be used to export natural gas from Qatar to Bahrain and Kuwait but has been postponed following Qatar's moratorium on further export projects – revised dates have not been announced; and

- The 24", 182 km pipeline linking Al-Ain with Fujairah, both in UAE, has the capacity to deliver 20 BCM of natural gas per year. It was completed in 2003 and initially operated by the Emirates General Petroleum Corporation but since 2006 it has been operated by Dolphin Energy. Until 2008, the pipeline was used to supply Omani natural gas to the Fujairah power and desalination plant but, when Dolphin gas began to flow in November 2008, the pipeline was used import gas from Qatar to Oman.

Dolphin Energy Limited[3] is the constructor and operator of the project.

In October 2003, Dolphin Energy signed significant long-term gas sales agreements with its initial customers, Abu Dhabi Water and Electricity Company (ADWEC) and Union Water & Electricity Company (UWEC). In May 2005 a similar long-term gas sales agreement was signed with the Dubai Supply Authority (DUSUP).

Dolphin Energy signed a long term Gas Sales Agreement with Oman Oil Company (OOC) in September 2005, committing to supply an average of 2 BCM of natural gas for 25 years from 2008. The signature of the Gas Sales Agreement with Oman Oil Company completed Dolphin Energy's major contracts for long term gas supply.

Dolphin has been producing, processing and transporting natural gas through its Export Pipeline from Ras Laffan, Qatar to Taweelah in Abu Dhabi, UAE since July 2007. In March 2008 the company reached full capacity of 57 MCM per day.

Dolphin Energy's average daily contracted gas volumes are as follows:

- ADWEC (Abu Dhabi Water & Electricity Company) – 22.1 MCM /day;

- DUSUP (Dubai Supply Authority) – 20.4 MCM/day;

- ADWEC, Fujairah - 3.95 MCM/day; and

- OOC (Oman Oil Company) - 5.6 MCM/day.

The difference between the total of these daily contracted volumes and the daily capacity of 57 MCM/day allows Dolphin to offer flexibility over the peak requirements of its customers.

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[3] www.dolphinenergy.com. Dolphin Energy is owned 51% by Mubadala Development Company, on behalf of the Government of Abu Dhabi and 24.5% each by Total of France and Occidental Petroleum of the USA.

A Phase-II of the Dolphin pipeline calls for capacity to be increased to nearly 90 MCM/day. The target date for Phase II completion was originally 2012 but Qatar has placed a moratorium on new gas development projects at its offshore North Field and the Phase II project has been put on hold for the foreseeable future[4].

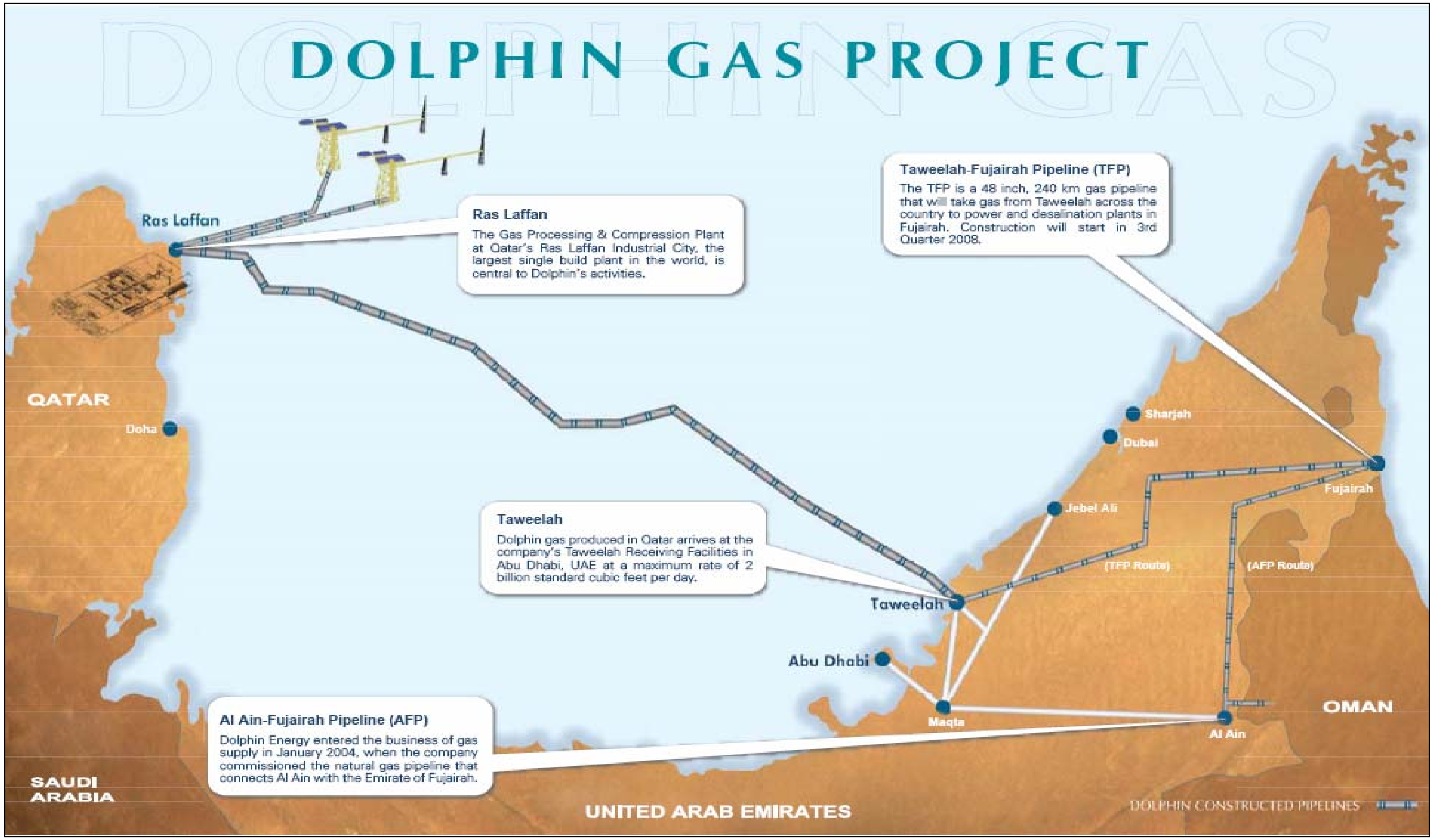
2.3 Other natural gas trade

While further expansion of gas exports from Qatar to other Gulf states via the Dolphin pipeline have been suspended, press reports[5] indicate that Dubai is moving ahead with a scheme to import natural gas as LNG, primarily from Qatar. The imports will be based around a floating storage and re-gasification unit to be moored offshore within the Jebel Ali Terminal and gas will be transported through a sub-sea pipeline to Dubai's natural gas network to industrial customers. The re-gasification plant is reported to have a capacity of three million tonnes of LNG per year which is equivalent to 4.1 BCM of natural gas. Shell will supply the scheme with LNG, primarily from its sources in Qatar.

[4] *Dolphin Imports From Qatar*, APS Review Gas Market Trends, May 26 2008
http://www.allbusiness.com/energy-utilities/oil-gas-industry-oil-processing/10549988-1.html

[5] Shell Press Release, 20 April 2008.

Figure 4 Dolphin gas project map



Source: http://www.meed.com

3 Kuwait

3.1 Energy resources

3.1.1 Gas reserves

Kuwait has 1.78 trillion cubic meters of proven natural gas reserves, estimated at the end of 2006 - slightly less than 1% of the world total. This places the country just outside the top 20 holders globally.

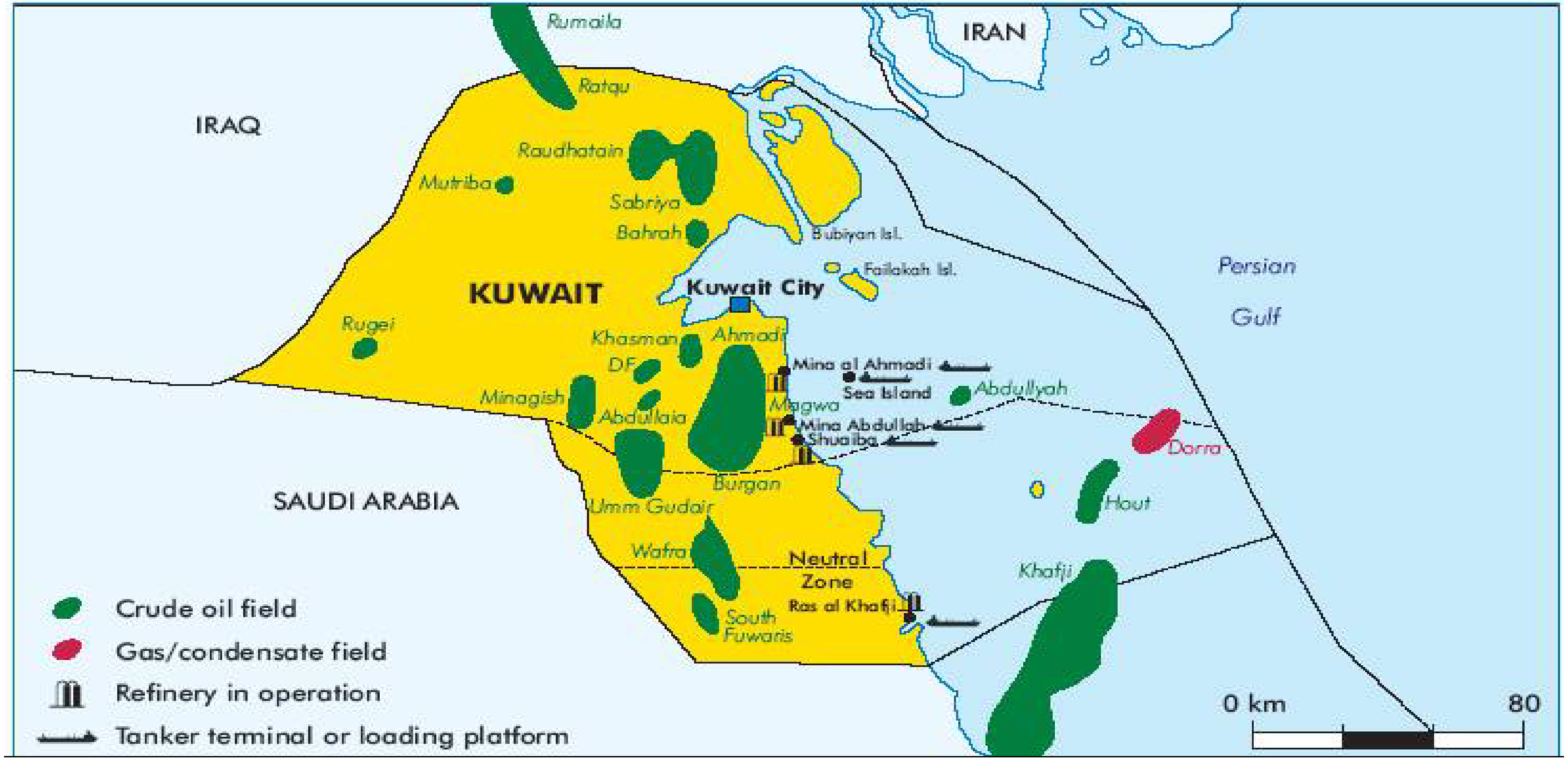
Table 1 Kuwait proven natural gas reserves - Kuwait

	at the end of 1987	at the end of 1997	at the end of 2006
Trillion cubic meters	1.21	1.49	1.78

Source: BP Statistical Review of World Energy, June 2008

Kuwait's gas reserves are almost entirely found in association with oil. Gas exploitation is accordingly linked to oil production and, by extension, OPEC quotas. This has contributed to past difficulties in sourcing sufficient gas to meet local demand. The location of gas resources are shown in Figure 5.

Figure 5 Kuwait gas resources and infrastructure



Source: IEA World Energy Outlook:, Middle-East and North Africa Insights, 2005

Kuwait hopes to increase its domestic natural gas production, both through reduced flaring of associated gas and through new drilling.

In recent years, Kuwait Oil Company (KOC) has stepped up efforts to discover non-associated gas, but these have been largely unsuccessful. However, in June 2006, non-associated gas was reportedly discovered onshore—in Umm Niqa, Sabriyah and Northwest Rawdatain—which according to studies is 60%-70% recoverable. KOC indicated that the new field will reach production of 5.1 MCM/day. This deposit is not yet officially classified as 'proved'; if it were to be, it would increase the country's reserves by 56% making Kuwait rank 11th in terms of gas reserves in the world[6].

Significant potential remains to increase reserves of associated gas. The focus of current drilling activity is on areas that are thought to contain gas rich deposits beneath the Raudhatain oilfield in the north, reaching geological formations much deeper than the oil deposits, which are believed to be gas rich.

Meanwhile, Kuwait and Saudi Arabia conduct seismic studies in the offshore Durragas field, which they share. Gas production is expected to reach 17 MCM/day.

Kuwait is also engaged in talks with Iran to resolve a long-running dispute over maritime borders, which would facilitate the development of the 200 BCM Dorra gas field which straddles Kuwaiti, Iranian and Saudi waters.

3.1.2 Gas production

Kuwaiti gas production fluctuates in line with oil output.

Table 2 Kuwait natural gas production

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
BCM	9.3	9.5	8.6	9.6	8.5	8.0	9.1	11.0	12.3	12.9	12.6

Source: BP Statistical Review of World Energy, June 2008

With reserves of only 1.78 trillion cubic meters, Kuwait hopes to significantly increase its use of natural gas in electricity generation, water desalination, and petrochemicals to free up as much as 100,000 bpd of oil for export.

Kuwait has made significant efforts to increase the share of its marketed natural gas production, including:

- Gas flaring has been reduced substantially and is targeted to be reduced further, but an estimated 2.1 BCM of gas continued to be flared in 2007 (see Table 79 in Annex A3).

[6] EIA, and GCC natural gas outlook (Global investment house, 2006) http://www.menafn.com/updates/research_center/Regional/Economic/GCC_natural_gas.pdf

- Natural gas gathering systems have been installed at each of Kuwait's oilfields. These are connected to a pipeline network which delivers the gas to the Kuwait National Petroleum Corporation (KNPC)'s facilities, where it is processed into feedstock for power generation and for petrochemicals and fertilizer production.

- In April 2006, Australia's WorleyParsons was awarded an engineering, procurement and construction management contract covering the Mina al-Ahmadi - Subiya natural gas-oil pipeline project to supply Subiya power station, north of Kuwait City.

In 2008, a little over 4 BCM of natural gas was used for power generation. If the same volume had been used in 2007 then, with total production of 12.6 BCM, the balance of gas, amounting to 8.6 BCM was used for the production of petrochemicals and fertilizers for export. Given Kuwait's shortage of natural gas for power generation and plans to import natural gas discussed below, the economic logic of this strategy is questionable.

3.2 Electricity demand

A forecast of peak electricity demand provided by the Ministry of Energy is shown in Table 3. Gross electricity production in 2008 was 52 TWh.

Table 3 Projections of peak electricity demand - Kuwait

Year	Peak demand (MW)
2008	9,710
2009	10,623
2010	11,509
2011	12,887
2012	14,273
2013	16,078
2014	17,238
2015	20,035
2016	21,495
2017	22,496
2018	23,585
2019	24,701
2020	25,954

Source: Ministry of Energy. Communication with the World Bank, July 2009.

3.3 Power generation capacity review

The installed capacity of power plants in Kuwait reached 10,300 MW in 2008. There are five plants that are distributed along the Arabian Gulf coast. These are[7]:

- Doha East, 1,050 MW installed capacity, in operation since 1980 and with 108 MW of gas turbines;
- Doha West, with steam turbine capacity 2,400 MW, in operation since 2004, and 85 MW of gas turbines;
- Al Subiya, 2,400 MW plant, which came partly on stream in 1998 and whose final units were commissioned in March 2001; the station also has 252 MW of gas turbine capacity;
- Shuaiba South, with a nameplate capacity of 800 MW and an output of 720 MW, in operation since 1970-1974; and
- Al Zour South started operation mid-2005 with 1,000 MW and in 2008 it had a total of 4,376 MW of installed capacity.

Table 4 Existing generation capacity (MW) - Kuwait

Plant	Gas turbines		Steam turbines		Total
	Units	Total	Units	Total	
Shuwaikh	6*42	252	-	-	252
Shuaiba South	-	-	6*120	720	720
Doha East	6*18	108	7*150	1,050	1,158
Doha West	3*28.2	85	8*300	2,400	2,485
Al Zour South	8*130 4*27.75 5*165	1,976	8*300	2,400	4,376
Al Subiya	6*41.7	250	8*300	2,400	2,650
Total		***2,671***		***8,970***	***11,641***

Source: Ministry of Energy, communication with the World Bank, July 2009.

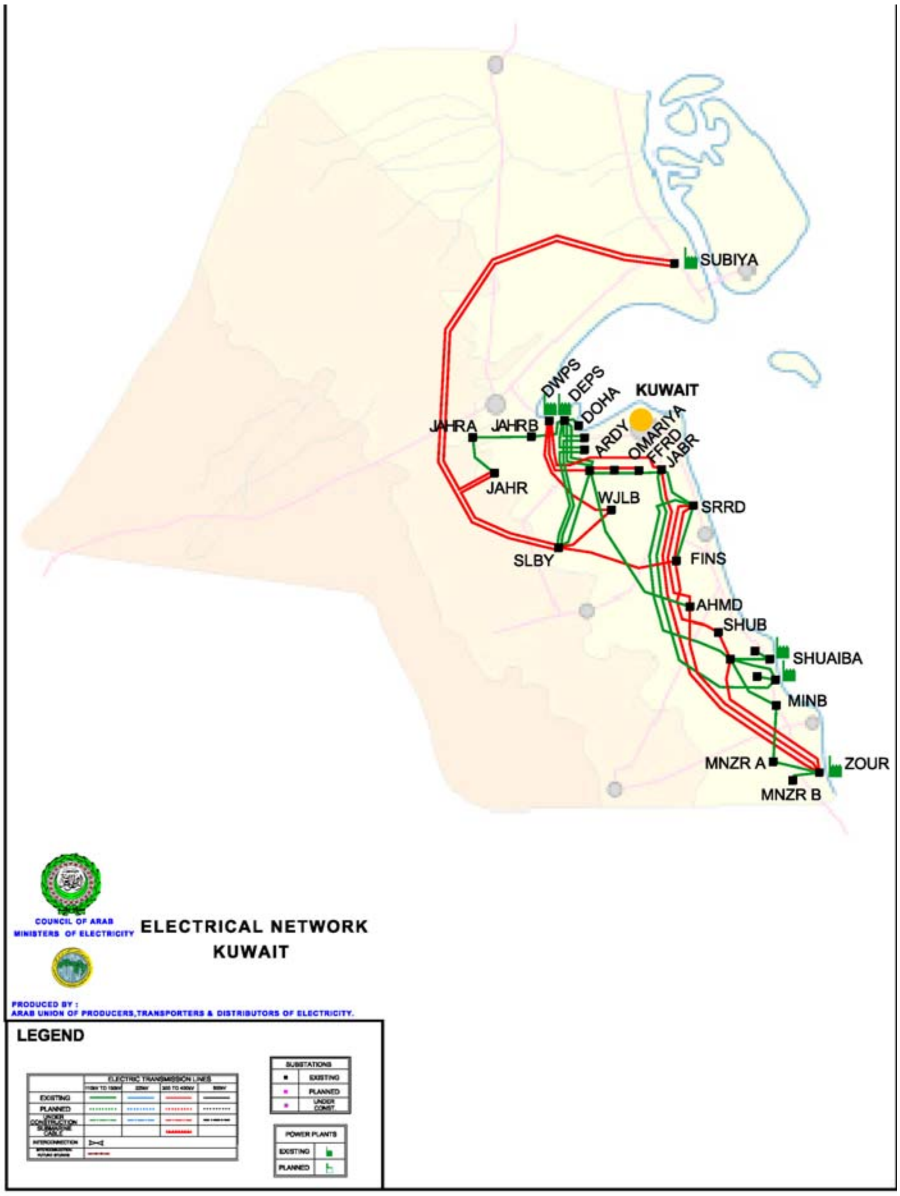
[7] Source: Arab Union of Producers, Transporters and Distributors, http://www.auptde.org, EIA and press reports

3.4 Electricity and gas transmission review

3.4.1 Electricity

Kuwait's transmission network includes voltages ranging from 110 kV up to 400 kV. The current network is shown in Figure 6.

Figure 6 Kuwait electricity network



Source: Arab Union of Producers, Transporters and Distributors of Electricity

Kuwait's electricity consumers are largely served by a single integrated grid. With the implementation of the GCC interconnection project, Kuwait's grid is now also connected to the GCC grid.

3.4.2 Natural gas

The map in Figure 5 in Section 3.1 shows the location of Kuwait's oil and natural gas resources. No information is available on the gas pipeline network.

3.5 Supply-demand balance for electricity

The supply-demand balance for electricity is shown in Table 5. The 7.6% required reserve margin is based on the value assumed in the GCC interconnection study (after completion of the GCC interconnection) but this appears very low. The Table suggests that over 18 GW of capacity will be required between now and 2020 after allowing for retirement of older plants scheduled between 2013 and 2016. As described in Section 3.6 below, 10 GW of capacity is under development or is planned.

Table 5 Electricity supply-demand balance, Kuwait

Year	Demand (MW)	Demand + 7.6% reserve margin (MW)	Installed capacity (MW)	Investment required (MW)
2009	10,623	11,430	11,641	0
2010	11,509	12,384	11,641	743
2011	12,887	13,866	11,641	2,225
2012	14,273	15,358	11,641	3,717
2013	16,078	17,300	11,281	6,019
2014	17,238	18,548	10,921	7,627
2015	20,035	21,558	10,342	11,216
2016	21,495	23,129	9,763	13,366
2017	22,496	24,206	9,763	14,443
2018	23,585	25,377	9,763	15,614
2019	24,701	26,578	9,763	16,815
2020	25,954	27,927	9,763	18,164

3.6 Electricity development plans

Kuwait announced plans in June 2008 to launch tenders for power expansion worth more than US$ 2.5 billion[8]. The plants under this program are:

[8] (Sourced from KUNA, Kuwait Bews Agency) Kuwait plans power expansion worth over USD2.5 bln Thu Jun 5, 2008

- Al-Zour North**:** The plant will have a nominal generating capacity of 2,500 MW. Originally planned to be a steam plant burning heavy fuel oil, as of February 2007 a decision was made to use gas instead of fuel oil. A further tender is expected to be issued in 2009 for a 4,700 MW plant, which is planned to be built in four phases, with completion scheduled for 2011.

- Al Zour South Conversion: The project will convert the existing 1,000 MW gas fired Al Zour South power plant to combined cycle. The scope of work includes supply and installation of heat recovery boilers and two steam turbines with a capacity of 250 MW each. The first units were scheduled to be commissioned in 2008 and the plant is expected to reach full capacity by the end of 2009.

- Shuaiba North: The proposed plant will be gas fired with a generating capacity of 800 MW and 0.21 MCM/day seawater (MSF) desalination plant. This is scheduled to start operation in the summer of 2010.

- Subiya**:** The proposed plant will have a capacity of 1,500 MW.

Kuwait is also installing two new gas turbines in its South Zour power station that will add another 320 MW starting in August 2009.

3.7 Demand for natural gas

3.7.1 Historical gas demand

Consumption of natural gas has been increasing sharply in recent years as shown in Table 6.

Table 6 Historical natural gas consumption - Kuwait

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
BCM	9.3	9.5	8.6	9.6	8.5	8.0	9.1	11.0	12.3	12.9	12.6

Source: BP Statistical Review of World Energy, June 2008

The bulk of electricity is currently provided by thermal power generation. Traditionally, oil and gas have been the dominant fuel sources in the power generation market in Kuwait. All plants burn natural gas to some extent and the share of natural gas in the fuel mix for power generation and water desalination has been increasing in the past few years but in 2006, of the total electricity production of 48 TWh, 35 TWh was fuelled by oil and only 13 TWh by gas[9]. Just over 4.1 BCM of gas was used for power generation in 2008.

[9] Source: Restructuring Kuwait Electric Power System: Mandatory or Optional? Proceedings of World Academy of science, engineering and technology Volume 35 November 2008 ISSN 2070-3740.

3.7.2 Gas demand projections

Business Monitor International has also produced a forecast for gas consumption in Kuwait (April 2009) which is summarised in Table 7. Gas demand is forecast to grow from 13 BCM in 2007 to 32 BCM in 2013. The projections beyond 2013 are calculated by the Consultant assuming a continuation of the 10.3% per annum trend predicted for 2013.

Table 7 Gas consumption forecast - Kuwait

Year	Source	BCM
2006	BP Statistical Review of World Energy, June 2008	13.0
2007	"	13.0
2008	BMI. Bahrain oil and gas report, Q2, 2009	14.0
2009	"	20.0
2010	"	23.0
2011	"	26.0
2012	"	29.0
2013	"	32.0
2014	ECA trend projection	35.3
2015	"	39.0
2016	"	43.0
2017	"	47.4
2018	"	52.3
2019	"	57.8
2020	"	63.7

3.8 Review of electricity and gas pricing

3.8.1 Electricity

Current electricity prices in Kuwait are shown in Table 8.

Table 8 Electricity prices in Kuwait (2009)

	Shuiaba industrial area	Chalets[10]	All other consumers
Fils (US¢)/kWh	1 (3.5)	10 (35.0)	2 (7.0)

Source: Ministry of Energy, communication with the World Bank, September 2009.

3.8.2 Gas

No information is available on natural gas prices in Kuwait.

3.9 Legal and regulatory framework

Kuwait's electric power system is vertically integrated utility that is owned and operated by the Ministry of Electricity and Water. Unlike other GCC states, Kuwait has not yet introduced the IWPP model but is seeking foreign investment for the construction of new plants.

[10] No information is available on this category of consumer.

4 Saudi Arabia

4.1 Energy resources

4.1.1 Proven gas reserves

According to BP, natural gas reserves stood at 7.07 trillion cubic meters at the end of 2006.

Table 9 Proven natural gas reserves - Saudi Arabia

Proven reserves	at the end of 1987	at the end of 1997	at the end of 2006
trillion cubic meters	4.19	5.88	7.07

Source: BP Statistical Review of World Energy, June 2008

Approximately 57%of Saudi Arabia's proven natural gas reserves consist of associated gas at the giant onshore Ghawar field and the offshore Safaniya and Zuluf fields. The Ghawar oil field alone accounts for approximately one-third of the country's proven natural gas reserves[11].

Gas reserves are expected to reach 7,420 billion cubic meters by 2011 (see Figure 7). The Kingdom holds the world's fourth-largest gas reserves and until now has had no problems meeting its gas needs.

Figure 7 Forecast for gas reserves - Saudi Arabia

Source: Global Research – May 08, GCC Natural Gas Sector – Dawn of the 'gas' era! Global Investment House.

For more than a decade, Saudi Aramco has aggressively explored on and offshore for additional reserves to meet growing demand, although success has been limited.

The majority of new natural gas discovered in the 1990s was associated with light crude oil, especially in the Najd region south of Riyadh. Over the last decade and a

[11] EIA country information, OPEC bulletins

half, Saudi Aramco has added around 2.1 trillion cubic meters of non-associated reserves, including the fields of Mazalij, Manjura, Shaden, Niban, Tinat, Al-Waar, and Fazran in the deep Khuff, Unaizah and Jauf reservoirs.

To meet growing domestic needs, in November 2006, the Petroleum Ministry and Saudi Aramco announced a US$ 9 billion strategy to add 1.4 trillion cubic meters of non-associated reserves between 2006 and 2016 through new discoveries (and potentially another 1.4 trillion cubic meters of associated reserves). In the last few years some important discoveries were made, including:

- Both associated and non-associated natural gas has been discovered in the country’s extreme northwest, at Midyan, and in the Empty Quarter (Rub al Khali) in the country's south eastern desert. The Rub al Khali is believed to contain natural gas reserves potentially as high as 8.4 trillion cubic meters, although these are not proven. The area remains under exploration.

- A large non-associated offshore natural gas field, Dorra (Durra), is located offshore near Khafji oil field in the Saudi-Kuwaiti Neutral Zone. Dorra development has been controversial since the late 1960s, however, because 70% is also claimed by Iran (called Arash).

- The offshore Jana-6 and an extension of Karan (Karan-7) were the major gas finds in 2007. The Karan gas field is the largest gas deposit yet discovered in the offshore Khuff formation, some 160 km north of Dhahran.

- Discoveries in 2006 included an earlier extension of the Karan field (Karan-6), with the potential to add 2.25 MCM/day to gas flows, and onshore, the Kassab-1 and the Zamalah wells in the Jauf Reservoir, which could add a combined 0.6 MCM/day.

According to the 2007 Saudi Aramco Annual Review, the company has increased the rate of exploration, drilling 73 development and exploratory wells in that year as compared to 35 in 2006 and 20 in 2005. Some 300 development and 70 exploratory wells are reportedly planned by 2010. Still according to the company, only 15%of Saudi Arabia has been "adequately explored for gas." To overcome the gas bottleneck, Saudi Aramco has launched an aggressive investment programme which involves:

- Fast-tracking development of the offshore Karan gas field in the Gulf and estimated to contain 0.25 trillion cubic meters. On completion, targeted for 2011, Karan is to produce 28 MCM/day. Recent non-associated gas finds are promising;

- Exploration of prospective areas along the Red Sea coast and in the country's north-west;

- Search in the Rub' al-Khali desert.

The Saudi domestic natural gas market, traditionally the sole domain of Saudi Aramco, is slowly being opened to private investment both in exploration and distribution, and increasing competition in the market.

- Saudi Arabia reached an agreement with Kuwait in July 2000 to share Dorra output equally, although the Kuwaitis are reportedly trying to purchase the Saudi share. According to Saudi Aramco, the field is estimated to contain non-associated gas reserves of 1.0 and 1.7 trillion cubic meters of natural gas, and is under seismic study. The Kuwaiti Ministry of Oil has reported that the goal is to produce initially 16.8 MCM/day from Dorra. Kuwait and Iran have intermittently discussed jointly developing the field, although production plans remain undisclosed.

- Recent reports also indicate that Saudi Arabia, Iran and Kuwait are expected to sign an agreement to develop non-associated gas reserves at Dorra, a field straddling their territorial waters with its reserves said to be large enough to feed a stream of more than 28 MCM/day.

- The South Rub al-Khali Company (SRAK), a consortium of Saudi Aramco and Royal Dutch/Shell, is exploring Shaybah and Kidan oil fields, abutting Oman and the UAE, and the Saudi-Yemeni border respectively, aiming to sell 14 MCM/day of gas.

- Russia's Lukoil is exploring for non-associated natural gas in the Empty Quarter, near Ghawar, as part of an 80/20 joint venture with Saudi Aramco, known as Luksar.

- Sino Saudi Gas, a venture of China's Sinopec has reported the first natural gas find in the Sheeh-2 area although the quantity is unconfirmed and geology reported to be complex.

4.1.2 Gas production

Highly subsidised prices and soaring costs of production, exploration, processing and distribution of gas have squeezed supply, while limiting investment in the sector and constraining other areas of economic and industrial growth. The situation is exacerbated by the fact that the majority of gas fields in Saudi Arabia are associated with oil, as discussed above.

Table 10 Natural gas production - Saudi Arabia

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
BCM	45.3	46.8	46.2	49.8	53.7	56.7	60.1	65.7	71.2	73.5	75.9

Source: BP Statistical Review of World Energy, June 2008

Saudi Arabia currently has seven gas processing plants with a total gas production capacity of approximately 0.26 BCM/day (75.9 BCM in 2007, according to BP – as shown in Table 10), including 1.1 million bbl/day of natural gas liquids (NGLs) and approximately 2,700 tons of sulphur at facilities at Berri, Shedgum, Uthmaniyah and Hawiyah.

According to statements made by Saudi Aramco, the country aims to process an estimated 0.36 BCM/day by the end of 2009 through additional facilities and capacity expansion. Mega-project plans are currently underway at Khursaniya, Hawiya, Ju'aymah, Yanbu' and Khurais.

Efforts are also made to reduce losses: according to OPEC and other sources, an estimated 13 to 14 percent of total production of natural gas in Saudi Arabia is lost to venting, flaring, re-injection and natural processes.

4.2 Electricity demand

Saudi Arabia's electricity demand was approximately 35,000 MW in 2008 and electricity sales were over 173,000 GWh.

A forecast of electricity sales prepared for the Ministry of Water and Electricity in 2007 for the four operating areas is provided in Table 11 below.

Table 11 System peak demand and energy forecast - Saudi Arabia by region

Year	COA		EOA		WOA		SOA	
	Demand (MW)	Sales (GWh)	Demand (MW)	Sales (GWh)	Demand (MW)	Sales (GWh)	Demand (MW)	Sales (GWh)
2008	11 713	51,953	11 784	63,611	11 775	52,751	2 792	12,736
2009	12 592	54,299	12 689	66,679	12 746	55,163	3 016	13,242
2010	13 462	56,925	13 547	70,455	13 708	57,863	3 251	13,870
2011	14 323	59,648	14 410	74,415	14 539	60,662	3 667	14,519
2012	15 184	62,468	15 256	78,569	15 418	63,563	4 216	15,191
2013	15 844	65,261	16 027	82,853	16 081	66,439	4 537	15,851
2014	16 525	68,156	16 790	87,350	16 761	69,421	4 861	16,533
2015	17 212	71,440	17 562	92,856	17 456	72,803	5 188	17,296
2016	17 894	74,873	18 321	98,702	18 161	76,340	5 522	18,092
2017	18 550	78,321	19 286	104,827	18 868	79,896	5 858	18,882
2018	19 202	81,931	20 369	111,335	19 556	83,621	6 202	19,709
2019	19 941	85,714	21 559	118,254	20 370	87,522	6 545	20,571
2020	20 711	90,191	23 060	127,045	21 268	92,141	6 901	21,576

Source: Demand forecast – Final Report, Development of Electricity Generation and Transmission Plan (EGTP), prepared for the Ministry of Water and Electricity by the Center for Engineering Research & SNC- LAVALIN, December 2007, Confidential.

The peak demand and sales forecasts for Saudi Arabia in aggregate for the interconnected networks are shown in Table 12.

Table 12 System peak demand and energy forecast - Saudi Arabia aggregate		
Year	**Demand (MW)**	**Sales (GWh)**
2008	34,708	173,185
2009	36,308	181,153
2010	38,141	190,460
2011	40,047	200,150
2012	42,029	210,239
2013	44,011	220,389
2014	46,073	230,965
2015	48,462	243,337
2016	50,971	256,356
2017	54,079	269,671
2018	56,762	283,701
2019	59,585	298,493
2020	63,001	316,565

Source: Demand forecast – Final Report, as for Table 11.

4.3 Power generation capacity review

According to the Saudi Electricity Company (SEC), electricity generating capacity reached 37,154 MW in 2007 – as shown in Table 13.

Table 13 Electricity generation capacity 2007 – Saudi Arabia		
Producing entity	**No. of plants**	**Capacity (MW)**
SEC	49	30,670
SWCC	12	3,426
Saudi Aramco	5	834
Tihamah Power Generation Co.	4	1,074
Marafiq (Yanbu)	1	900
Jubail Power Co.	1	250
Total	72	*37,154*

Source: ECRA Annual report, 2007

In 2007 natural gas supplied 52% of power generation, followed by heavy fuel oil (19%), diesel (18%), and crude oil (11%). In the eastern region natural gas is used for most of the power plants.

Table 14 describes generating plants with their capacity in 2007 based on a report prepared for the Electricity & Cogeneration Regulatory Authority (ECRA) in 2006[12]. This was supplemented with data from SEC for 2007.

Table 14 Existing power generating capacity – Saudi Arabia

	Plants			
Eastern Operating Area	**Station No.**	**Plant name**	**Plant type**	**Total generating capacity (MW)**
	1	Ghazlan- I	Steam turbine	1,600
	2	Ghazlan- II	Steam turbine	2,528
	3	Qurayyah	Steam turbine	2,500
	4	Shedgum	Gas turbine	1,069
	5	Faras	Gas turbine	803
	6	Dammam	Gas turbine	615
	7	Berri	Gas turbine	171
	8	Uthmaniyah	Gas turbine	284
	9	Juaymah	Gas turbine	91
	10	Qaisumah	Gas turbine	123
	11	Sfaniyah	Gas turbine	63
Central Operating Area	**Station No.**	**Plant name**	**Plant type**	**Total generating capacity (MW)**
	1	Riyadh PP9X	Gas turbine	480
	2	Riyadh PP9	Combined cycle	1,417
		Riyadh PP9	Gas turbine	814
	3	Riyadh PP8	Gas turbine	1,588
	4	Riyadh PP7	Gas turbine	1,113
	5	Riyadh PP5	Gas turbine	538
	6	Riyadh PP4X	Gas turbine	90
	7	Riyadh PP4	Gas turbine	215
	8	Riyadh PP3	Gas turbine	55
	9	Qassim PP3	Gas turbine	816
	10	Buraydah	Gas turbine	89
	11	Hail2	Gas turbine	302
	12	Hail1	Gas turbine	43
	13	Layla	Gas turbine	81
Western Operating Area	**Station No.**	**Plant name**	**Plant type**	**Total generating capacity (MW)**
	1	Jeddah PP3	Gas turbine	1,318
	2	Jeddah PP2	Gas turbine	116
	3	Rabigh	Steam turbine	1,572
	4	Rabigh	Combined cycle	1,091
	5	Sha'iba	Steam turbine	4,323
	6	Makkah	Gas turbine	778
	7	Madinah	Gas turbine	318

[12] *Revised final report updated generation planning for the Saudi electricity sector, Prepared for Electricity & Cogeneration Regulatory Authority (ECRA) Riyadh, Saudi Arabia, by Centre for Engineering Research,* Safar *1427 H March 2006.*

	Plants			
	8	Taif	Gas turbine	116
	9	Yanbu	Gas turbine	55
Southern Operating Area	**Station No.**	**Plant name**	**Plant type**	**Total generating capacity (MW)**
	1	Asir CPS	Gas turbine	433
	2	Asir CPS	Diesel units	77
	3	Jizan CPS	Gas turbine	677
	4	Jizan CPS	Diesel units	24
	5	Bisha CPS	Gas turbine	144
	6	Baha CPS	Gas turbine	24
	7	Baha CPS	Diesel units	51
	8	Tihama CPS	Gas turbine	482
	9	Njran CPS	Gas turbine	267

4.4 Electricity and gas transmission review

4.4.1 Electricity

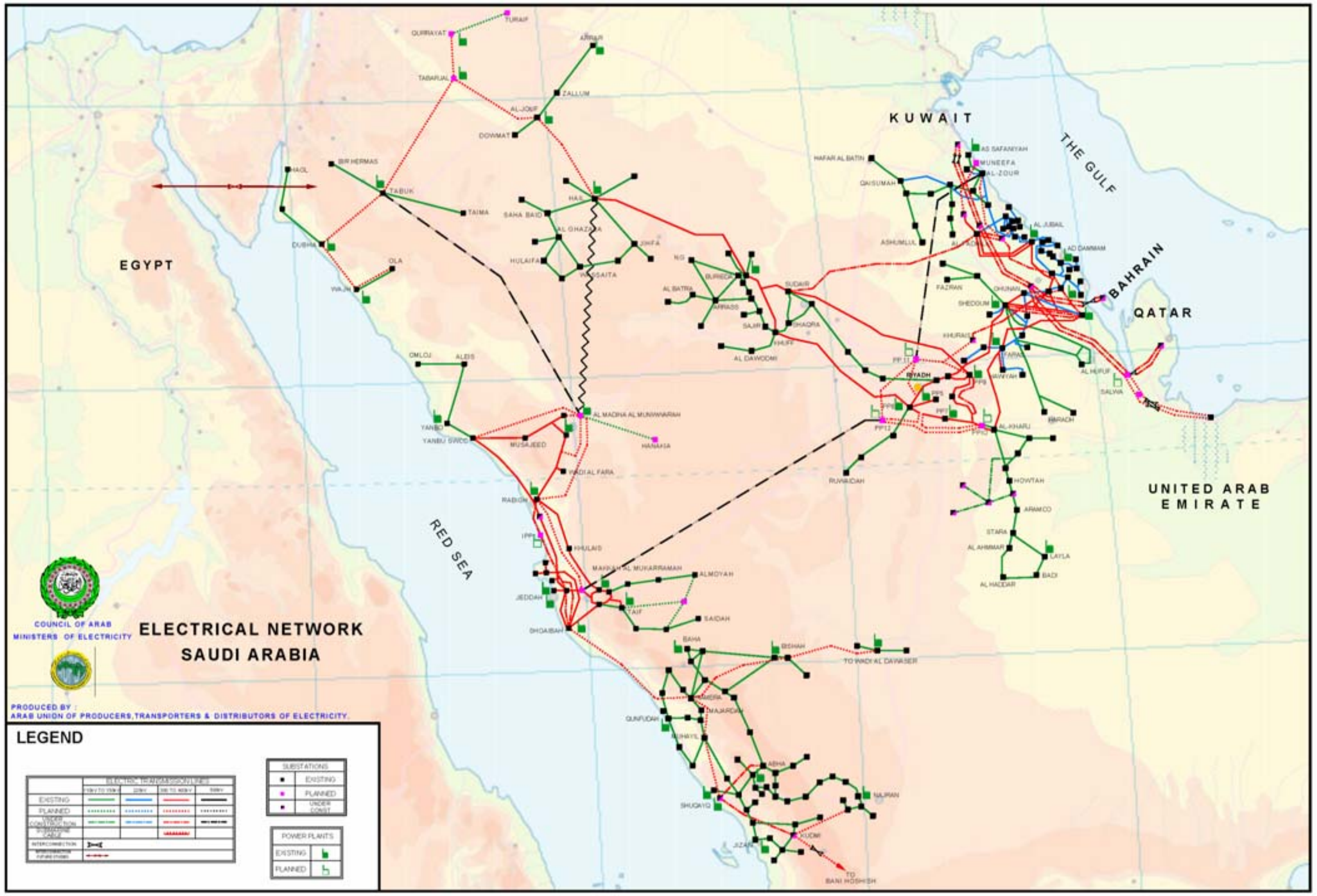
The electric power system in Saudi Arabia is divided into four operating areas: Eastern, Central, Western and Southern.

- The Eastern, Central, and Western operating areas have only a small number of isolated systems.
- The Northern region has a number of isolated systems that are managed by the Eastern and Western operating areas.
- The Southern operating area has four autonomous systems that are not interconnected with each other but there is a plan to link these four systems.

The Eastern and the Central operating areas are interconnected by 230 kV and 380 kV overhead lines. Hail and Qassim are also interconnected by 380 kV lines.

The network is shown in Figure 8 and schematically in Figure 9.

Figure 8 Electricity map - Saudi Arabia



Source: Arab Union of Producers, Transporters and Distributors of Electricity

Figure 9 Schematic electricity map of Saudi Arabia showing the operating areas

Source:Saudi Electricity Company, Annual Report 2007 www.se.com.sa

Steps are also being taken to increase the power exchange between operating areas within the Kingdom. Table 15 summarises the plans to interconnect the isolated areas and some of the operating areas as well as the GCC interconnections. The major interconnection between operating areas will be that between EOA and COA and it is intended that EOA will supply power to COA.

Table 15 Intereconnections, current and planned - Saudi Arabia

Importing operating Area	Importing from	Year	Maximum capacity (MW)
Eastern	SWCC	all years	1,888
	WEC	2012 onwards	333
	WEC	2013 onwards	1,000
	Maaden	2011 onwards	600
	Marafiq	2009	1,373
	Marafiq	2010 onwards	2,746
	SADAF	2008	250
	GCC *	2010 onwards	1,200
Central	EOA	2008	2,800
	EOA	2009-2010	3,700
	EOA	2011 onwards	4,700
Western	SWCC	all years	700
	WEC	2009 onwards	300
	WEC	2010 onwards	900
Southern	WEC	2010 onwards	285
		2011 onwards	850
Total			34,825

* the GCC interconnector is planned to be used for reserve sharing

Source: Demand forecast – Final Report, Development of Electricity Generation and Transmission Plan (EGTP), prepared for the Ministry of Water and Electricity by the Center for Engineering Research & SNC- LAVALIN, December 2007, Confidential.
Abbreviations: SEC = = Saudi Electricity Company, SWCC = Saline Water Conversion Corporation; WEC= Water and Electricity Company; SADAF = Saudi Petrochemical Company.

The study examining the benefits of interconnecting the operating areas is described in Annex A2.

We understand that there is an ongoing study for the interconnection of Saudi Arabia with Egypt but no information is available to us on this study.

A study of the interconnection of Yemen with the SOA of Saudi Arabia was prepared in 2006 by Tractabel and is discussed in Section 11.

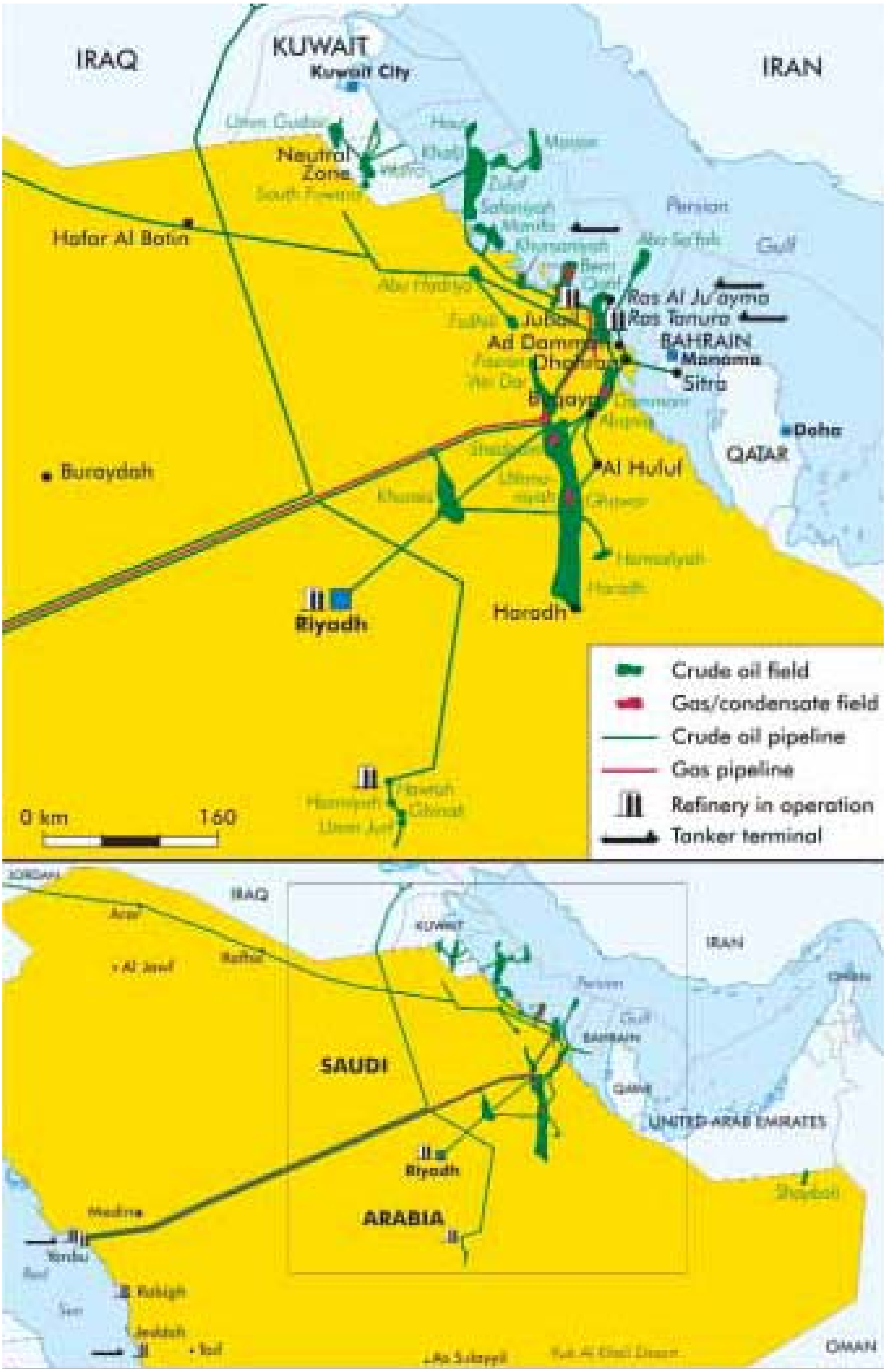
4.4.2 Natural gas

Saudi Aramco, the state-owned oil company, is the operator of the Master Gas System (MGS) - the network which brings natural gas to industrial users, first built in 1975. The MGS now has a capacity of 224 MCM/day.

The MGS feeds gas to the industrial cities including Yanbu, on the Red Sea, and Jubail. A key pipeline project was completed in June 2000 to extend the MGS from the Eastern Province (which contains large potential gas and condensate reserves) to the capital in the Central Province. This is part of a broader expansion of the existing gas transmission system in Saudi Arabia, reportedly to include the construction of around 1,930 km of additional natural gas pipeline capacity (on top of 16,895 km of oil, gas, and condensate, products, and NGL pipelines currently in operation). Since 2001, the MGS has been fed entirely by non-associated gas.

In order to feed the expanded gas processing facilities, several additions to the MGS are in the planning or construction phases. The largest pipeline to be built is to the Rabigh complex and the existing Yanbu' NGL processing facility, a distance of 223 km. Installation of four pipelines will connect Manifa to the Khursaniyah gas plant and Ras az-Zour for gas processing and power production.

Figure 10 Oil and gas Infrastructure in Saudi Arabia



Source: IEA World Energy Outlook:, Middle-East and North Africa Insights, 2005

4.5 Supply-demand balance for electricity

The supply-demand balance for electricity is shown in Table 16. The 6.6% required reserve margin is based on the value assumed in the GCC interconnection study (after completion of the GCC interconnection) but this appears very low. The Table suggests that over 30 GW of capacity will be required between now and 2020 in addition to any capacity needed to compensate for plant scheduled to be retired.

Table 16 Electricity supply-demand balance, Saudi Arabia

Year	Demand (MW)	Demand + 6.6% reserve margin (MW)	Installed capacity (MW)	Investment required (MW)
2009	36,308	38,704	37154	1,550
2010	38,141	40,658	37154	3,504
2011	40,047	42,690	37154	5,536
2012	42,029	44,803	37154	7,649
2013	44,011	46,916	37154	9,762
2014	46,073	49,114	37154	11,960
2015	48,462	51,660	37154	14,506
2016	50,971	54,335	37154	17,181
2017	54,079	57,648	37154	20,494
2018	56,762	60,508	37154	23,354
2019	59,585	63,518	37154	26,364
2020	63,001	67,159	37154	30,005

4.6 Electricity development plans

A comprehensive least-cost generation investment plan was prepared for Saudi Arabia's Water and Electricity Ministry and the Electricity & Cogeneration Regulatory Authority (ECRA) by the Centre for Engineering Research in 2006[13]. This was, however, based on a demand forecast which, at the time, expected peak demand of 58 GW in 2023 for the Kingdom in aggregate including both interconnected and isolated systems.

The latest forecast prepared for the Ministry of Water and Electricity by the Center for Engineering Research and SNC- LAVALIN in 2007 and described in Section 4.2

[13] *Revised final report updated generation planning for the Saudi electricity sector, Prepared for Electricity & Cogeneration Regulatory Authority (ECRA) Riyadh, Saudi Arabia, by Centre for Engineering Research, Safar 1427 H March 2006.*

suggests that demand will substantially higher at 78 GW in 2023 (interconnected plus isolated). For the year 2020, the comparison would be approximately 53 GW for the earlier forecast and 66 GW for the latest forecast, an increase of 24%. We do not, however, have the latest investment plan associated with this new (2007) demand forecast. We therefore provide below the investment plan based on the earlier (2006) demand forecast. This is shown in Table 17. For reference, the demand forecast on which that investment plan was based is provided in Annex A1.

Table 17 Generation investment plan (MW capacity) – Saudi Arabia

Year	EOA		COA	WOA			SOA	
	125 MW GT	600 MW ST	116 MW GT	123 MW GT	400 MW ST	600 MW ST	123 MW GT	250 MW ST
2008			812				369	
2009	250		464					
2010				369				
2011			696	246	400			
2012	375		696	246	400		123	
2013	500		696	369	400		246	
2014			696	246	400		246	
2015	250		812	246	400		492	
2016	125	600	696	246	400		369	
2017	125	600	696	369	400		369	
2018	125	600	696	123		600	123	250
2019	250	600	812	123		600	123	250
2020	125	600	696	615			369	250

Source: See footnote 14.

4.7 Demand for natural gas

4.7.1 Historical demand for gas

Despite sizable reserves and increasing demand, dry marketed natural gas production and consumption in Saudi Arabia remain limited. The demand in 2007 was estimated at 75.9 BCM.

[14] *Revised final report updated generation planning for the Saudi electricity sector, Prepared for Electricity & Cogeneration Regulatory Authority (ECRA) Riyadh, Saudi Arabia, by Centre for Engineering Research, Safar 1427 H March 2006.*

Table 18 Gas consumption - Saudi Arabia

Saudi Arabia	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
BCM	45.3	46.8	46.2	49.8	53.7	56.7	60.1	65.7	71.2	73.5	75.9

Source: BP Statistical Review of World Energy (2008)

Demand for gas from power and water desalination plants account for nearly 52% of the Kingdom's gas consumption, with the remaining 45% used as feedstock for petrochemicals. 70,217 GWh of electricity in the Kingdom was produced using natural gas (around 50%of the fuel demand by the power sector)[15].

4.7.2 Gas demand projections

According to press reports, Saudi demand is rising at 6% per year for dry gas and 9% per year for wet gas. A strong growth in Saudi gas demand is expected in the future as well. According to Saudi Aramco forecasts, natural gas demand in the Kingdom is expected nearly to double to 150 BCM by 2030, up from 76 BCM in 2007[16] at an average growth rate of 3% per year. The year-by-year forecast using a 3% per annum growth rate is shown in Table 19.

Table 19 Forecast gas consumption – Saudi Arabia

Year	Gas (BCM)
2007	76.0
2008	78.3
2009	80.6
2010	83.0
2011	85.5
2012	88.1
2013	90.7
2014	93.5
2015	96.3
2016	99.2
2017	102.1
2018	105.2
2019	108.4

[15] Source: Saudi Electricity Company, Annual Report 2007 www.se.com.sa.

[16] US - Saudi Arabia Business Council http://www.us-sabc.org/custom/news/dayetails.cfm?id=99

Year	Gas (BCM)
2020	111.6

Source: Development of Alternative Energy Technologies in Bahrain, WB 2008. Original source: National Oil and Gas Authority, Electricity Directorate. (Confidential)

4.8 Review of electricity and gas pricing

4.8.1 Electricity

Current electricity tariffs in Saudi Arabia are among the lowest in the world. Table 20 describes these tariffs.

Table 20 Electricity tariff structure - Saudi Arabia

Consumption, kWh	Commercial and residential	Industrial	Agricultural
	Halala and (US cents/kWh)		
0 - 1000	5 (1.3)	12 (3.1)	5 (1.3)
1001-2000	5 (1.3)	12 (3.1)	5 (1.3)
2001-3000	10 (2.7)	12 (3.2)	10 (2.7)
3001-4000	10 (2.7)	12 (3.2)	10 (2.7)
4001-5000	12 (3.2)	12 (3.2)	10 (2.7)
5001-6000	12 (3.2)	12 (3.2)	12 (3.2)
6001-7000	15 (4.0)	12 (3.2)	12 (3.2)
7001-8000	20 (5.3)	12 (3.2)	12 (3.2)
8001-9000	22 (5.9)	12 (3.2)	12 (3.2)
9001-10000	24 (6.4)	12 (3.2)	12 (3.2)
More than 10000	26 (6.9)	12 (3.2)	12 (3.2)

Source: World Bank, based on Ministry of Water and Electricity of Saudi Arabia. Note, for customers at 110 kV and above, tariffs are negotiated.

Saudi Arabia's Council of Ministers is reviewing recommendations for the restructuring of the country's electricity tariffs based on recommendations from ECRA (Electricity and Cogeneration Regulatory Authority) and a tariff study prepared by ECRA in 2006-07. The proposed new tariff structure seeks to address the industry’s chronic revenue shortfalls. Time-of-use tariffs proposed by ECRA have already been introduced.

4.8.2 Natural gas

With the aim to promote gas-based industries to local and international investors, the Saudi Government offers gas at a price of only US$ 0.75/mmbtu. The low price is a challenge to the foreign oil operators in the Kingdom hoping to exploit resources in some of the more remote areas of the country. The low price has also been challenged by the EU and is an issue with regard to negotiations over Saudi Arabia's entry to the World Trade Organisation (WTO).

As a result of concerns over the low gas prices, some changes have taken place. In mid-2006, the local Eastern Gas Company (EGS) was awarded a two-year contract to become Aramco's gas distributor to consumers in the Dhahran industrial area, with the purchase price from Aramco being at a level of US$1.12/mmbtu and a sale price of US$1.34/mmbtu (according to press reports). In Riyadh, the Natural Gas Distribution Company was granted a license to supply several small-scale manufacturing plants, with a similar pricing structure.

4.9 Legal and regulatory framework

The Ministry of Water and Electricity is responsible for planning and policy making.

The Saudi Electricity Company (SEC), which incorporated all previous electrical energy companies in the Kingdom was formed in April 2000. SEC currently operates as a vertically integrated business covering generation, transmission, and distribution activities.

The Saudi Electricity Regulatory Authority was formed in 2001 but in 2004 it became Electricity and Co-Generation Regulatory Authority (ECRA)[17]. By law, ECRA is a financially and administratively independent Saudi organisation, which regulates tariffs and market access in the electricity and water desalination industry.

SEC is responsible for tendering and procurement of IPPs. Ownership is normally structured with SEC having 10% of the equity, the developer having 60% and third parties 30%. In the absence of a third party investor, SEC or the developer may take this share of the equity.

The Shoaiba IWPP, scheduled to be completed in 2009, will be the first of four to be implemented by the private sector. The Saudi Basic Industries Corporation (SABIC), the Saudi Arabian Oil Company (Saudi Aramco) and the Royal Commission for Jubail and Yanbu have also combined with private investors to set up a utility company – Marafiq - to expand water and power supply in the industrial cities of Jubail and Yanbu.

Saudi Arabia has further plans to restructure the electricity sector, including unbundling of SEC in stages and the introduction of competition. However, no steps have yet been taken.

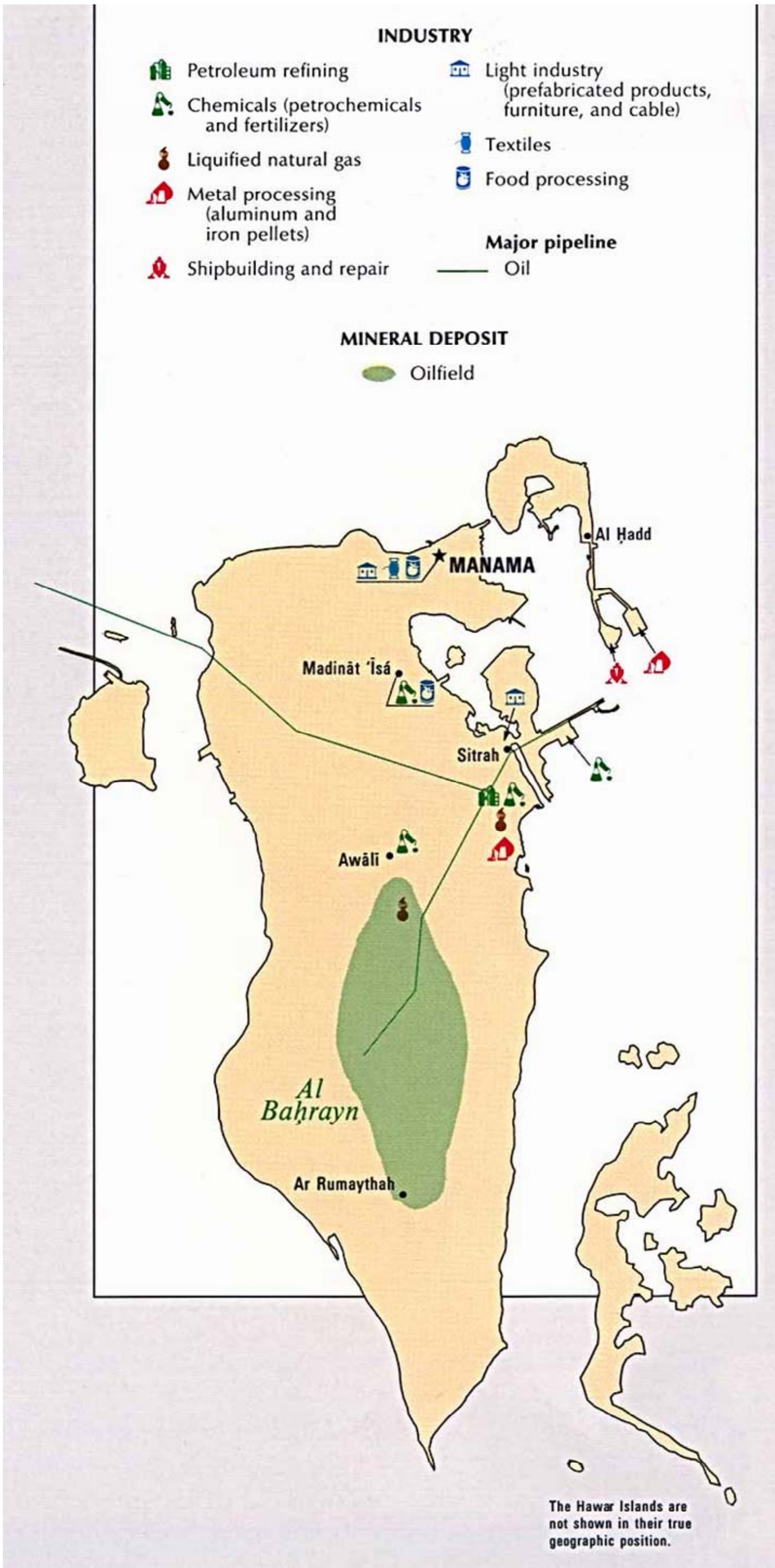
[17] Website: www.ecra.gov.sa

5 Bahrain

5.1 Energy resources

The Bahrain National Gas Company (BANAGAS) is 75% owned by the Government and 12.5% by Caltex Bahrain and 12.5% by the Arab Petroleum Investment Corporation. The Company was formed with the primary objectives of processing associated gas into marketable products and supplying gas for local industrial use. In September 2003, the government signed an agreement with the American firm Alcoa, allowing Alcoa to take up to a 26% percent equity stake in BANAGAS.

Figure 11 Oil and gas map of Bahrain



Source: http://www.lib.utexas.edu/maps/atlas_middle_east/bahrain_econ.jpg

5.1.1 Proven gas reserves

Bahrain has proven natural gas reserves of about 90 BCM at the end of 2006, much of it associated gas from the Awali oil field (see Figure 11).

Table 21 Proven natural gas reserves - Bahrain

	at the end of 1987	at the end of 1997	at the end of 2006
Trillion cubic meters	0.20	0.14	0.09

Source: BP Statistical Review of World Energy, June 2008

Bahrain started a fresh upstream initiative in 2007 based on restructured offshore blocks as part of efforts to boost the Kingdom's natural gas reserves. The initiative is one of the first to emerge from the recently-formed National Oil and Gas Authority (NOGA).

While Bahrain hopes to make new oil discoveries to stem its declining production, exploring for new sources of natural gas to ensure the Kingdom's security of supply has now become a priority. NOGA is currently working on a strategy, based on an assumption of increasing gas demand, notably for power and desalination, as new ventures are established in the Kingdom.

5.1.2 Gas production

The decline in the oil production has prompted Bahrain to increase production of its substantial natural gas reserves. To help meet rising demand, the Bahrain Petroleum Company (BAPCO) is leading an effort to increase the country's natural gas supply. BAPCO plans to increase natural gas production incrementally over the next several years, including drilling new wells and improving natural gas recovery rates at existing fields.

The total production of both natural and associated gas in Bahrain during 2007 was 11.5 BCM.

Table 22 Bahrain gas production

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
BCM	8.0	8.4	8.7	8.8	9.1	9.5	9.6	9.8	10.7	11.1	11.5

Source: BP Statistical Review of World Energy, June 2008

In 2007 production of associated gas decreased in comparison with 2006, while the overall gas production increased by 6.8%, as shown in Table 23.

Table 23 Production of associated and non-associated gas, Bahrain

	2007	2006	percent
Natural gas, BCM	11.4	10.7	6.80
Associated gas, BCM	2.80	3.00	5.90
Total, BCM	14.2	13.7	4.00

Source: National Oil and Gas Authority of Bahrain

5.2 Electricity demand

5.2.1 Historical electricity demand

As shown in Table 24, net energy demand generation grew sharply during the last ten years, reaching 10,689 GWh in 2007. Maximum demand reached 2,136 MW.

Table 24 Key electricity statistics, 2007- Bahrain

Period	Load factor (%)	Maximum demand (MW)	Net energy generation (GWh)	Number of consumers
2000	55.0	1,307	6,297	180,284
2001	56.2	1,376	6,779	187,145
2002	57.0	1,459	7,278	193,501
2003	57.8	1,535	7,768	200,622
2004	57.8	1,632	8,267	211,211
2005	57.8	1,725	8,867	221,101
2006	58.4	1,906	9,744	234,416
2007	57.1	2,136	10,689	na

Source: Bahrain Ministry of Electricity and Water, www.mew.gov.bh

The growth trend continued in 2008, with peak load just below 2,400 MW and energy generation at 11,657 GWh.

5.2.2 Electricity demand projections

The Ministry of Electricity and Water's 15-year master plan expects electricity demand to reach 19,706 GWh by 2020 and that peak demand will grow to 4,312 MW by 2020 (Table 25).

Table 25 Electricity Demand Forecast (2003-2020) - Bahrain		
Year	**Energy Sales (GWh)**	**Peak Demand (MW)**
2010	11,183	2,469
2015	15,301	3,349
2020	19,706	4,312

Source: Development of Alternative Energy Technologies in Bahrain, WB 2008.Original Source Ministry of Electricity and Water of Bahrain, (confidential)

5.3 Power generation capacity review

According to Business Monitor International (BMI), Bahrain approached 2,500 MW of installed electric generating capacity in the beginning of 2009[18].

At present, Bahrain gets its power from two combined water and power production complexes and two smaller electricity-only plants. In the last several years Bahrain has launched several modernisation projects at these generation units. In particular:

- **Hidd:** Currently, there are 2 phases of power plant on the site, with a third phase already planned. Phase I has a power capacity of 280 MW gross with a desalination capacity of 30 million gallons per day (MIGD), which entered full commercial operation in early 2000. Phase II currently has a power capacity of 675 MW and entered full commercial operation in 2004.

- **Al Ezzel:** In 2007 Bahrain completed its first private power project, Al Ezzel. The gas-fired plant started commercial operation in April 2006, with a capacity of 470 MW and the full capacity of 950 MW was reached in April 2007.

- **Sitra:** the power plant entered into operation in 1975. In 2009, the refurbishment of the plant was launched. Its current capacity is 125 MW.

- **Riffa:** When completed in 2009, as a result of major modernisation project, the capacity of the plant will be 700 MW.

5.4 Electricity and gas transmission review

5.4.1 Electricity

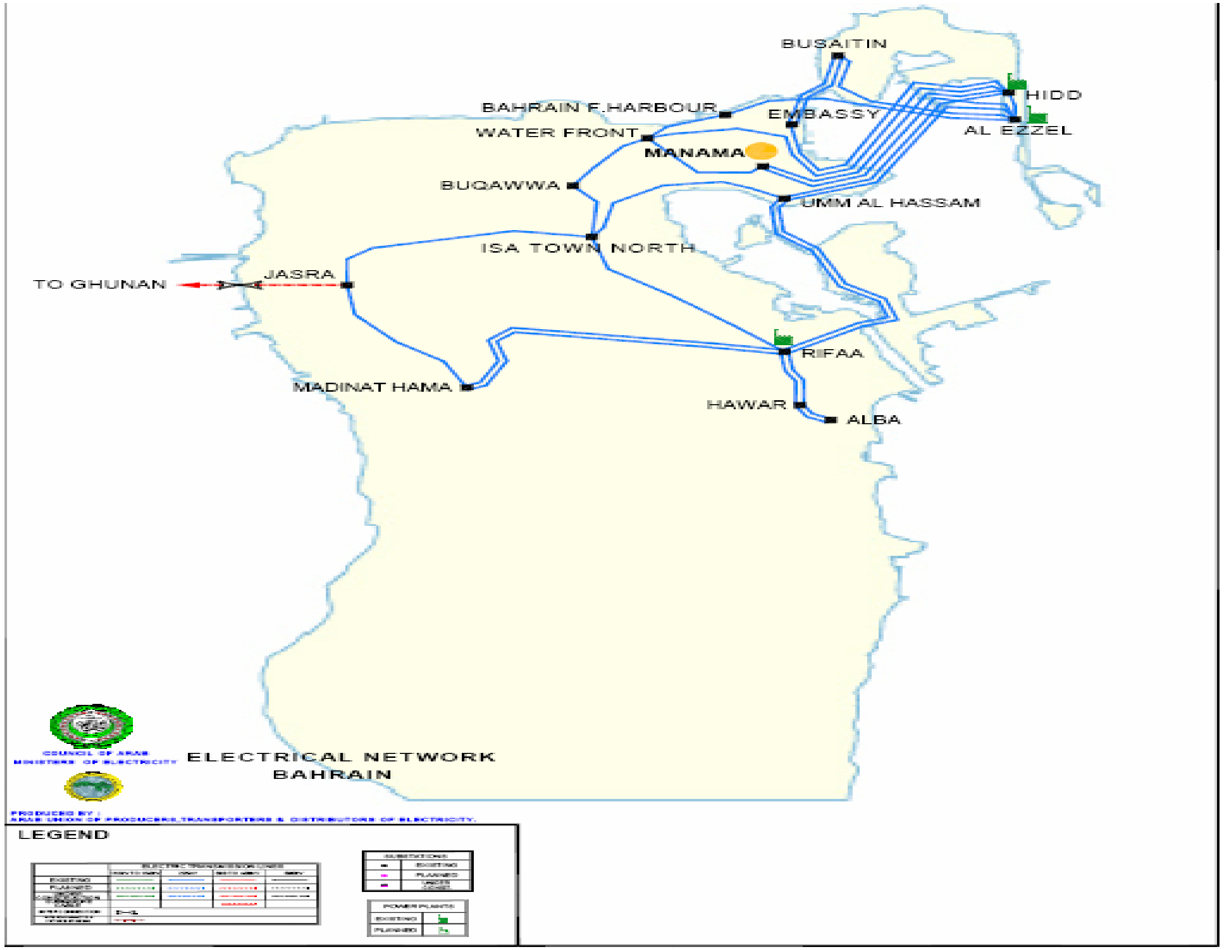
Bahrain's electricity network is owned and operated by the Electricity and Water Authority and is shown in Figure 12. The Authority's network includes 220 kV, 66

[18] Source: Bahrain oil and gas report, Q2, 2009, BMI

kV and 33 kV transmission lines, the majority of which is at 66 kV and mostly underground.

With the recent interconnection to the GCC interconnected grid, Bahrain can now import 600 MW from other members of the regional grid.

Figure 12 Map of electricity grid of Bahrain



Source: www.auptde.org

5.4.2 Natural gas

No maps appear to exist showing the gas transmission network of the Bahrain Petroleum Corporation (Bapco) which is responsible for the production and transportation of natural gas in Bahrain.

5.5 Supply-demand balance for electricity

The supply-demand balance for electricity is shown in Table 26. The 10.1% required reserve margin is based on the value assumed in the GCC interconnection study (after completion of the GCC interconnection) but this appears very low. The Table suggests that over 2,000 MW of capacity will be required between now and 2020 in addition to any capacity needed to compensate for plant scheduled to be retired. As described in Section 5.6 below, 1,200 MW of capacity is under development or is planned.

Table 26 Electricity supply-demand balance, Bahrain

Year	Demand (MW)	Demand + 10.1% reserve margin (MW)	Installed capacity (MW)	Investment required (MW)
2009	2,353	2,531	2,500	31
2010	2,469	2,657	2,500	157
2011	2,624	2,824	2,500	324
2012	2,789	3,001	2,500	501
2013	2,965	3,190	2,500	690
2014	3,151	3,390	2,500	890
2015	3,349	3,604	2,500	1,104
2016	3,523	3,790	2,500	1,290
2017	3,705	3,987	2,500	1,487
2018	3,897	4,194	2,500	1,694
2019	4,099	4,411	2,500	1,911
2020	4,312	4,640	2,500	2,140

5.6 Electricity development plans

Recently the government announced an international bid for a contract to build and run a 1,200 MW Al Dur power and desalination plant expected to be commissioned by the summer of 2011.

No other information is available on power investment plans in Bahrain.

5.7 Demand for natural gas

5.7.1 Historical demand for gas

The demand for natural gas is growing at the rate of 6% per annum as shown in Table 27.

Table 27 Historical gas consumption (2000-2006) - Bahrain

Year	Gas (BCM)
2000	9.1
2001	9.5
2002	9.6
2003	9.7
2004	9.3
2005	10.3
2006	11.0

Source: Development of Alternative Energy Technologies in Bahrain, WB 2008. Original source: National Oil and Gas Authority, Electricity Directorate. (Confidential)

Gas consumption in Bahrain was slightly over 13.7 BCM in 2007, of which 2.6 BCM was reinjected. Gas is consumed by the Electricity & Water Authority and other power companies (29%), Aluminium Bahrain (ALBA) (28%), re-injected for oil field operation (20%), the Gulf Petrochemical Industries Company (GPIC) (9%) and the refinery (8%). The balance of 6% is distributed to other industrial companies operating in Bahrain.

5.7.2 Gas demand projections

Forecasts of gas demand to 2013 prepared by BMI are shown in Table 28. These have been extended to 2020 based on the trend growth rate of 9.9% per annum from 2008-2013.

Table 28 Gas consumption forecast - Bahrain

Year	Source	BCM
2006	BMI. Bahrain oil and gas report, Q2, 2009	10.0
2007	“	9.0
2008	“	10.0

Year	Source	BCM
2009	"	11.0
2010	"	13.0
2011	"	14.0
2012	"	15.0
2013	"	16.0
2014	ECA trend projection	17.6
2015	"	19.3
2016	"	21.2
2017	"	23.3
2018	"	25.6
2019	"	28.1
2020	"	30.9

5.8 Review of electricity and gas pricing

5.8.1 Electricity

Electricity prices are maintained at low levels in Bahrain partly to encourage development of energy intensive industries. Present electricity tariffs are summarised in Table 29.

Table 29 Electricity tariffs (2007) - Bahrain

Tariff	US ¢/kWh
Most Industries, except the following[19]:	**4.36**
Industrial Charges	3.27
Industrial Factories	4.36
Private Hospitals	3.27
GPIC	2.72
Residential	
1-3000 units	0.82
3000-5000 units	2.45
5000+ units	4.36

[19] No explanation is given of the difference between industrial, industrial charges and industrial factories.

Tariff	US ¢/kWh
Non-Residential (Government Schools and Hospitals)	
1-2000 units	1.63
2000-5000 units	3.27
5000+ units	4.36

Source: Ministry of Electricity and Water

The average cost of electricity supply is expected to increase by about 150% to 200% by 2018[20]. The low electricity price, along with the high economic growth rate, has resulted in a rapid growth of electricity consumption in Bahrain. The Government realises that adjusting the electricity price to more realistic ranges will help to not only lower the amount of government's subsidy but also promote load management and system efficiency. The Government is considering options for electricity tariff reform.

5.8.2 Natural gas

Bahrain's energy pricing policy is based on heavily subsidising almost all of the energy products. Until 2004 natural gas was priced at US$0.25/mmbtu for the power sector and US$0.75/mmbtu for other major users. The government adopted a new pricing policy in 2005 by setting a unified price of US$1.0/mmbtu for all users and a gradual escalation formula which would take the price to US$1.4/mmbtu by 2010 (see Table 30).

Table 30 Historical and projected gas prices by sector - Bahrain

	Historical and projected gas prices by sector (US$/mmbtu)					
	Power Sector	**Alba**	**Refinery**	**GPIC**	**GIIC**	**Others**
2000	0.25	0.75	0.70	0.75	0.75	1.00
2001	0.25	0.75	0.70	0.75	0.75	1.00
2002	0.25	0.75	0.70	0.75	0.75	1.00
2003	0.25	0.75	0.70	0.75	0.75	1.00
2004	0.25	0.75	0.70	0.75	0.75	1.00
2005	1.00	1.00	1.00	1.00	1.00	1.00
2006	1.00	1.00	1.00	1.00	1.00	1.00
2007	1.10	1.10	1.10	1.10	1.10	1.10

[20] *Development of Alternative Energy Technologies in Bahrain*, World Bank, 2008 (confidential).

	Historical and projected gas prices by sector (US$/mmbtu)					
	Power Sector	**Alba**	**Refinery**	**GPIC**	**GIIC**	**Others**
2010	1.40	1.40	1.40	1.40	1.40	1.40

Source: National Oil & Gas Authority

A World Bank report - *Development of alternative energy technologies in Bahrain* - estimates the economic cost of gas in Bahrain and predicts a gas price for 2018-2020 at about US$8/mmbtu - close to the fuel oil price on per unit of energy basis[21].

5.9 Legal and regulatory framework

Before 2004, Bahrain's power sector was 100% state-owned but in 2004, Bahrain's Ministry of Finance and National Economy awarded a contract for a 950 MW CCGT plant to the Bahraini Al Ezzel Power Company – which began operation in April 2006 - and this marked the introduction of the Build Own Operate (BOO) model in Bahrain. Further reform took place in January 2007 when foreign investors (International Power, Suez Energy of Belgium, and Sumitomo of Japan) acquired the Al Hidd power and water plant from the government.

The Electricity and Water Authority is the single buyer for power from the BOO plants and is also the regulator.

Electricity production and distribution in Bahrain is the responsibility of the Ministry of Electricity and Water.

[21] *Development of Alternative Energy Technologies in Bahrain*, World Bank, 2008 (confidential).

6 Qatar

6.1 Energy resources

6.1.1 Gas reserves

According to BP forecasts, Qatar's proven natural gas reserves stood at 25.64 trillion cubic meters as of January 2007, about 15% of total world reserves and the third-largest in the world behind Russia and Iran. Among the GCC members Qatar holds the highest reserves, followed by Saudi Arabia, then the UAE.

Table 31 Proven natural gas reserves - Qatar

	at the end of 1987	at the end of 1997	at the end of 2006
Trillion cubic meters	4.44	8.50	25.64

Source: BP Statistical Review of World Energy, June 2008

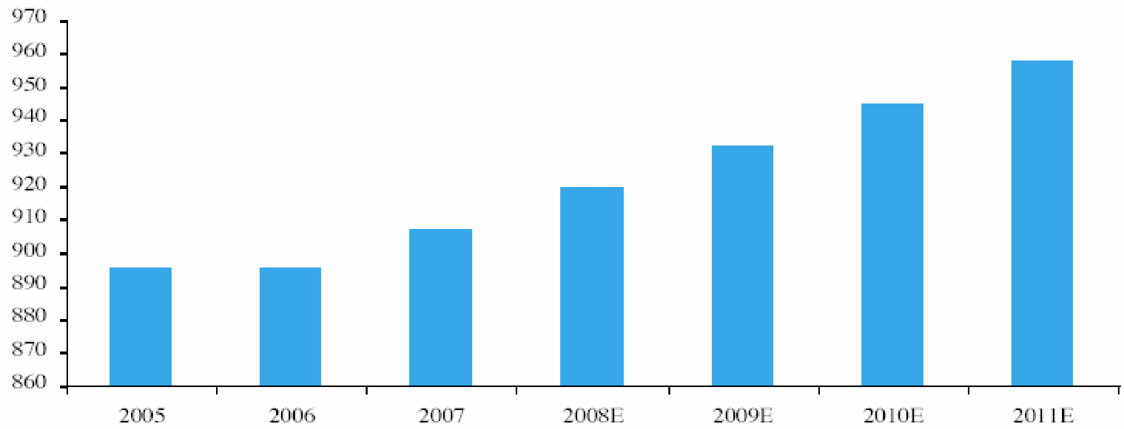
Most of Qatar's natural gas is located in the massive offshore North Field[22], which holds more than 25.2 trillion cubic meters of proven natural gas reserves and is the world's largest non-associated natural gas field. The North Field is a geological extension of Iran's South Pars field, which holds an additional 7.84 trillion cubic meters of recoverable natural gas reserves. The remaining reserves are located in the fields of Dukhan, which contain 0.2 trillion cubic meters, and other small fields.

The increasing demand of gas in international market has led the country into aggressive exploration and drilling activities, carried out by international and local companies. According to BP, proven gas reserves will reach 26.7 TCM in 2011.[23]

[22] EIA country information

[23] Qatar Economic and Startegic Outlook, 2008, Global Investment House, http://www.first-qatar.com/dayata/site1/pdf/Qatar_June_08.pdf

Figure 13 Gas reserves forecast (TCF)- Qatar



Source: Global Research – May 08, GCC Natural Gas Sector – Dawn of the 'gas' era! Global Investment House.

In 2005, Qatari government officials became worried that the North Field's natural gas reserves were being developed too quickly, which could reduce pressure in the field's reservoirs and possibly damage its long-term production potential. In early 2005, the government placed a moratorium on additional natural gas development projects at the North Field pending the results of a study of the field's reservoirs. This assessment is not expected to be completed until after 2009, which means that no new projects are likely to be signed before 2010. Recent press reports indicate that the moratorium could be extended to 2012.

However, this freeze did not affect projects that were approved or underway before the moratorium, which are expected to add significantly to Qatar's natural gas production in the next few years.

6.1.2 Gas production

Natural gas production in the country has increased during 2002-2007 with a CAGR of 12.3%, which is mainly due to the increase in gas demand on global front. Natural gas production levels stood at 59.7 BCM in 2007.

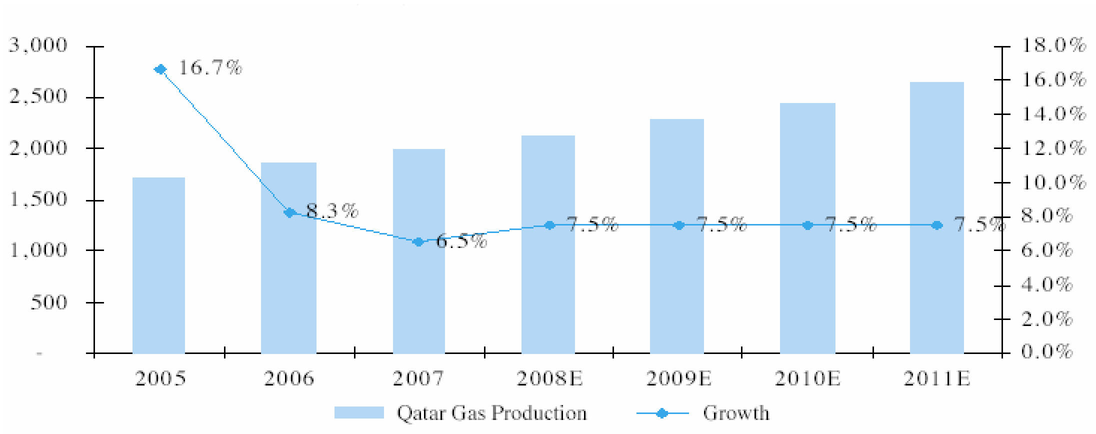
Table 32 Natural gas production - Qatar

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
BCM	17.4	19.6	22.1	23.7	27.0	29.5	31.4	39.2	45.8	50.7	59.7

Source: BP Statistical Review of World Energy, June 2008

The total production of both natural and associated gas in Qatar during 2007 increased by 4% in comparison with 2006 (total production of associated gas decreased by 5.9%, while the total production of non-associated natural gas increased by 6.8%. According to BP natural gas production will reach 70 BCM by 2011, as in Figure 14.

Figure 14 Natural gas production forecast (BCF) - Qatar



Source: Global Research – May 08, GCC Natural Gas Sector – Dawn of the 'gas' era! Global Investment House.

6.1.3 Gas-to-Liquids

In February 2007, ExxonMobil cancelled its planned 154,000 bpd Palm gas-to-liquids (GTL) project, which would have been the largest GTL facility in the world if completed.

GTL projects have received significant attention in Qatar over the last several years, and Qatar's government had originally set a target of developing 400,000 bpd of GTL capacity by 2012. However, project cancellations and delays since the North Field reserve assessment has substantially lowered this target.

By 2012, Qatar is likely to have 177,000 bbl/day of GTL capacity at two facilities: the Oryx GTL plant and the Pearl GTL project.

- Oryx GTL is a joint-venture of QP (51%) and Sasol-Chevron GTL (49%), and has the capacity to produce 34,000 bpd of liquid fuels. The plant was formally commissioned in June 2006 and the first export cargo began in April 2007. The Oryx project uses about 3 BCM of natural gas per year as feedstock from the Al Khaleej field. Depending on the outcome of the North Field reservoir study, Oryx GTL may choose to expand production capacity of the plant in the future.

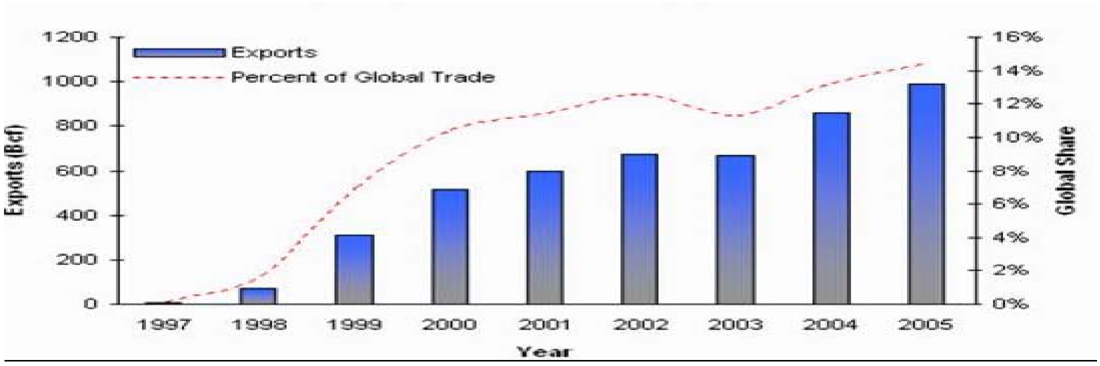
- In February 2007, Shell launched its Pearl GTL Project. The Pearl plant will be 51% owned by QP, though Shell will act as the operator of the project with a 49% stake. The facility is expected to use 16 BCM of natural gas per year feedstock to produce 140,000 bpd of GTL products as well as 120,000 bpd of associated condensate and LPG. The Pearl GTL project will be developed in phases, with 70,000 bpd of GTL product capacity expected by 2010 and a second phase expected in 2011.

6.1.4 Liquefied Natural Gas

In 1997, Qatar began exporting LNG when it sent small amounts of LNG to Spain. In 2005, Qatar exported 27.64 BCM of LNG, or 14.5% of all globally traded LNG. By

2006, Qatar surpassed Indonesia to become the largest exporter of LNG in the world.

Figure 15 Qatar LNG Exports



Source : EIA

Figure 16 describes Qatar LNG infrastructure.

Figure 16 Qatar LNG infrastructure, 2007

Unit	Liquefaction Capacity	Start-up	Primary Market(s)
	RasGas Facilities		
Trains 1 & 2	2 x 3.2 MMt (320 Bcf)	Aug. 1999	South Korea
Train 3	4.7 MMt (230 Bcf)	Feb. 2004	India
Train 4	4.7 MMt (230 Bcf)	Aug. 2005	Europe
Train 5	4.7 MMt (230 Bcf)	Mar. 2007	Europe & Asia
Train 6	7.8 MMt (380 Bcf)	2008	U.S.
Train 7	7.8 MMt (380 Bcf)	2009	U.S.
	Qatargas Facilities		
Trains 1 - 3	3 x 3.2 MMt (468 Bcf)	Dec. 1996	Japan & Spain
Trains 4 & 5	2 x 7.8 MMt (760 Bcf)	2008	UK
Train 6	7.8 MMt (380 Bcf)	2009	US
Train 7	7.8 MMt (380 Bcf)	2010	US, Europe
Source: RasGas, Qatargas, media reports			

Source: EIA

6.2 Electricity demand

Electricity generation was 17.8 TWh in 2007[24] - an increase of 16.3% over the previous year. The latest Qatar Oil & Gas Report from BMI forecasts[25] projects that the country's power consumption is expected to increase from an estimated 17.8 TWh in 2007 to 32.4 TWh by the end of 2018, an annual average growth rate of 5.6% per annum. This growth rate exceeds the 2.9% average growth rate that was forecast in the IEA's 2005 World Energy Outlook[26]. Demand projections based on BMI's predictions of 5.6% per annum are shown in Table 33.

[24] http://store.businessmonitor.com/power/qatar_power_report

[25] http://store.businessmonitor.com/power/qatar_power_report

[26] IEA, *World Energy Outlook:, Middle-East and North Africa Insights, 2005*

Table 33 Demand projections - Qatar

Year	Generation (TWh)	Peak demand (MW)
2008	18.8	3,749
2009	19.8	3,959
2010	21.0	4,180
2011	22.1	4,415
2012	23.4	4,662
2013	24.7	4,923
2014	26.1	5,198
2015	27.5	5,490
2016	29.1	5,797
2017	30.7	6,122
2018	32.4	6,464
2019	34.2	6,826
2020	36.1	7,209

Source: ECA calculations based on BMI forecast. Note, though the outturn 2008 peak demand is believed to have exceeded the figure in the Table above, a forecast is intended to predict trends and is not expected to be accurate in each and every year.

6.3 Power generation capacity review

Almost all Qatar's power generation is based on open-cycle gas turbines and all power plants are fuelled with natural gas. The Qatar Electricity and Water Company (QEWC), also known as Kahramaa, currently accounts for approximately 68%of all electricity generation and a majority of the nation's desalinated water capacity. QEWC has more than doubled its production capacity in the past ten years. It had a total installed capacity of 2,113 MW and desalination capacity of 0.4 MCM/day in 2007.

The main power plants currently are[27]:

- **RAF 'A'**. The primary combined-cycle plant built in Qatar between 1970 and 1993 is RAF 'A'. The total capacity of the plant is now 626 MW of electricity and 0.07 MCM/day of potable water. Forming part of RAF 'A' some satellite stations consist of AI Wajbah, Al Saliayah and Doha South Super located on the outskirts of Doha, generating only power. These plants were built in 1980 and have capacities of 301 MW, 134 MWand 67 MW respectively.

[27] http://www.qewc.com/web.nsf/locations?OpenPage

- ❑ **RAF 'B'.** Commissioned in the year 1995, RAF 'B' is a combined-cycle plant located in the southern part of the country, 25 km from the city of Doha. The total capacity of the plant is 609 MW of Electricity and 0.03 MCM/day of potable water.

- ❑ **RAF 'B1'.** Commissioned in 2002, RAF'B1' is an open-cycle plant with a capacity of 376 MW.

- ❑ **Dukhan.** Commissioned in 1997, the 44 MW plant was acquired by QEWC in the year 2003 from Qatar Petroleum (QP). It is located in the eastern part of the country, 70 km from Doha.

- ❑ **Ras Laffan Power plant-**the first gas-fired independent water and power producing (IWPP) venture in Qatar is located at the Ras Lafan Industrial City. The total capacity of the plant is 750 MW of electricity. The plant began operation in 2003.

- ❑ **Q POWER (Ras Laffan B).** Built in the city of Ras Laffan, the plant has a capacity of 1,025 MW of electricity and was scheduled to be completed by mid-2008.

Kahramaa's other committed projects include:

- ❑ **Extension of Ras Abu Fontas Station (RAF 'B2').** The commercial operation of this combined power and water plant began at the end of year 2008 with a total production capacity of 567 MW of electricity.

- ❑ **Mesaieed Power Project (Mesaieed A**). The completion of phase I for electricity production is now scheduled to be completed in May 2009 and completion of phase II in July 2009. The station's production capacity will be 2,007 MW.

- ❑ **Ras Girtas Project**. The first phase of this power and desalination plant is expected to be completed in 2010 and the full development in 2011 to give a total capacity of 2,730 MW of electricity.

- ❑ **Ras Laffan C.** The Ras Laffan plant will have the capacity to produce as much as 2,600 MW of power from 2010, making it Qatar's largest power and desalination facility.

Additionally, a 1,350 MW power plant is to be built for an aluminium smelter. The power plant and the smelter are expected to be on stream in late 2009.

6.4 Electricity and gas transmission review

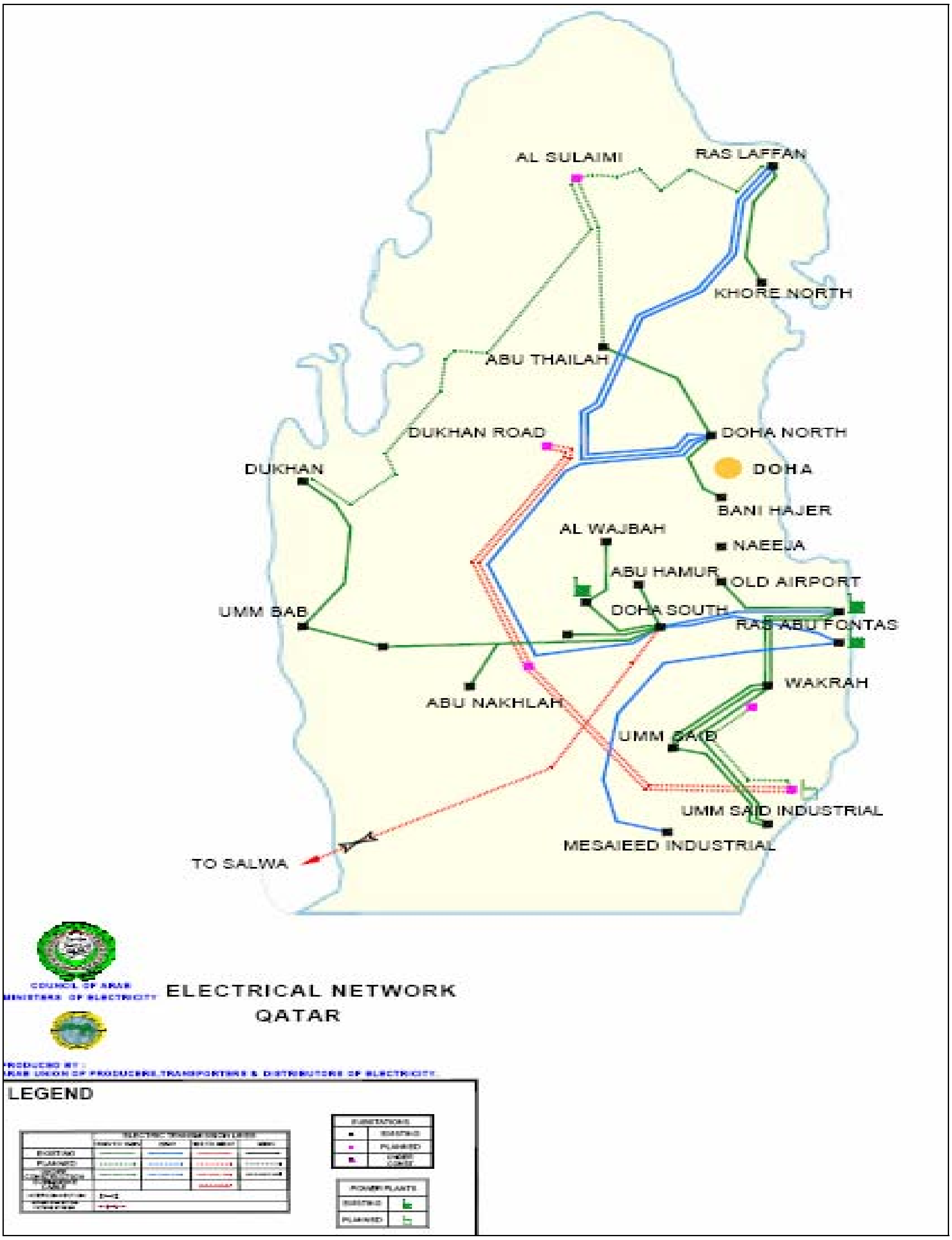
6.4.1 Electricity

Qatar's electricity grid is shown in Figure 17. The grid is owned and operated by the Qatar General Electricity & Water Corporation[28] or Kahramaa and includes voltage levels of 11 kV, 66 kV, 132 kV and 220 kV.

Within the framework of GCC interconnected, Qatar will be able to import 750 MW through the Doha South 400/220 kVA substation.

[28] www.kahramaa.com.qa

Figure 17 Electricity map of Qatar



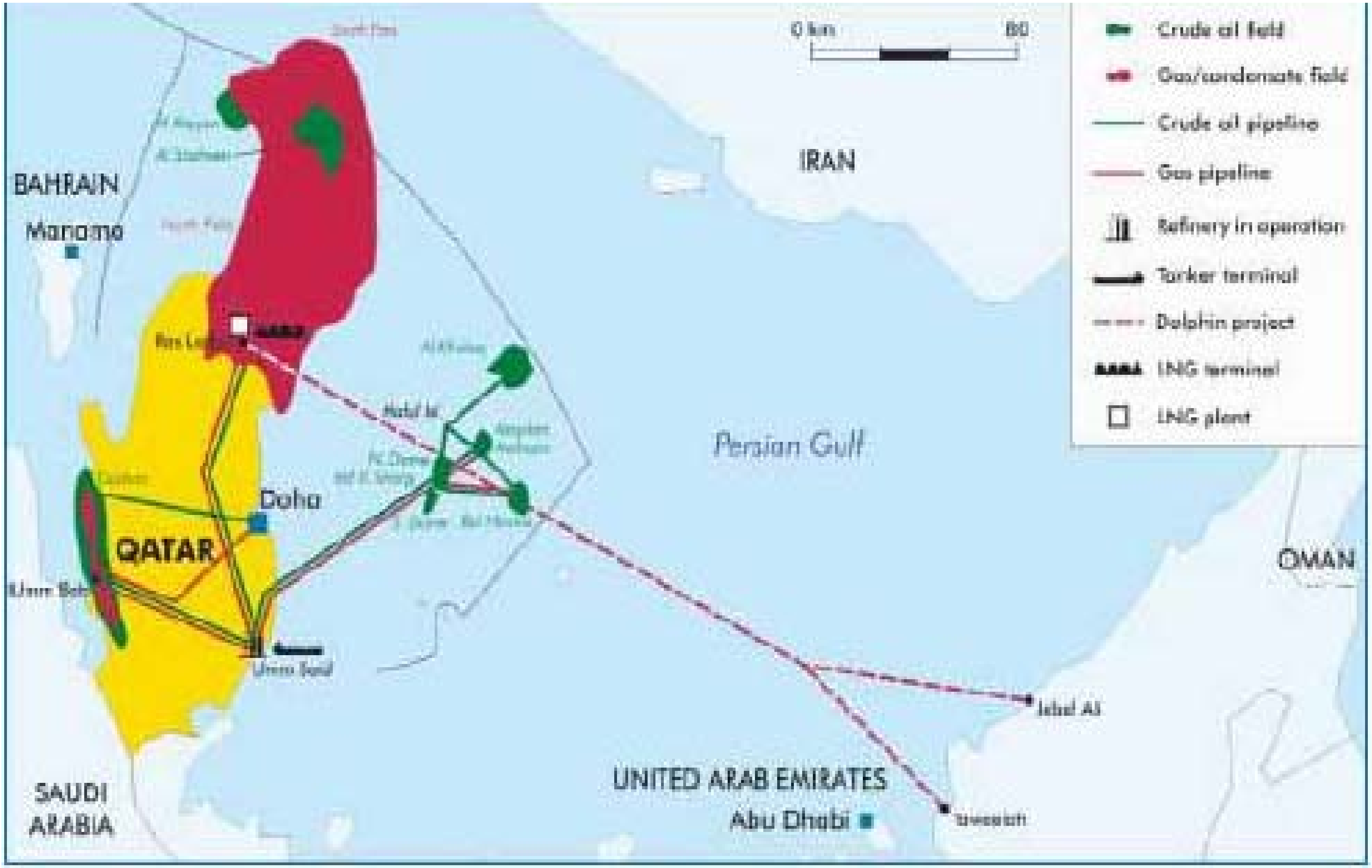
Source: http://www.auptde.org

6.4.2 Natural gas

All the natural gas for Qatar's LNG plants comes from the North Field. Qatar's LNG sector is dominated by Qatar LNG Company (Qatargas) and Ras Laffan LNG Company (RasGas). The LNG companies handle all upstream to downstream natural gas transportation.

In addition to the LNG projects and the Dolphin pipeline project, described in Section 2, other North Field projects include the Al Khaleej Gas Project, which provides gas for the domestic market including the Ras Laffan power plant, the Oryx GTL Project and to end-users located in Mesaieed Industrial City, south of Doha. The Al Khaleej Gas Project began producing gas in 2005. A gas map for Qatar is shown in Figure 18.

Figure 18 Oil and gas map of Qatar



Source: IEA World Energy Outlook:, Middle-East and North Africa Insights, 2005

6.5 Supply-demand balance for electricity

The supply-demand balance for electricity is shown in Table 34. The 8.8% required reserve margin is based on the value assumed in the GCC interconnection study (after completion of the GCC interconnection) but this appears very low. The Table suggests that over 4,700 MW of capacity will be required between now and 2020 in addition to any capacity needed to compensate for retired plant.

Table 34 Electricity supply-demand balance, Qatar

Year	Demand (MW)	Demand + 8.8% reserve margin (MW)	Installed capacity (MW)	Investment required (MW)
2009	3,959	4,307	3,107	1,200
2010	4,180	4,548	3,107	1,441
2011	4,415	4,804	3,107	1,697
2012	4,662	5,072	3,107	1,965
2013	4,923	5,356	3,107	2,249
2014	5,198	5,655	3,107	2,548
2015	5,490	5,973	3,107	2,866
2016	5,797	6,307	3,107	3,200
2017	6,122	6,661	3,107	3,554
2018	6,464	7,033	3,107	3,926
2019	6,826	7,427	3,107	4,320
2020	7,209	7,843	3,107	4,736

6.6 Electricity development plans

Other than the on-going investments described in Section 6.3, no other information is available on power investment plans in Qatar.

6.7 Demand for natural gas

6.7.1 Recent demand

Gas consumption, excluding gas injected into the oilfields and gas allocated for export, was 20.5 BCM in 2007. Gas was the dominant fuel in 2007, accounting for 82% of primary energy demand, followed by oil at 18%.

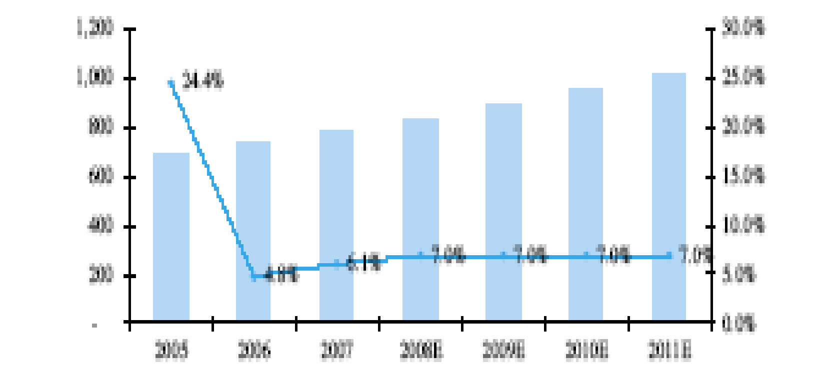
Table 35 Historical natural gas consumption - Qatar											
	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
BCM	14.5	14.8	14.0	9.7	11.0	11.1	12.2	15.0	18.7	19.6	20.5

Source: BP Statistical Review of World Energy, June 2008

6.7.2 Gas demand projections

BP forecasts that gas demand in Qatar will reach 28 BCM in 2011. Another forecast of gas demand is provided by Global Investment House and reproduced in Figure 19.

Figure 19 Gas Consumption forecast (BSF) - Qatar



Source: Global Research – May 08, GCC Natural Gas Sector – Dawn of the 'gas' era! Global Investment House.

Based on the information in Figure 19, we have projected gas demand to 2020 as shown in Table 36 at an annual average growth rate of 6.1%.

Table 36 Gas consumption forecast - Qatar

Year	Source	BCM
2006	BMI. Bahrain oil and gas report, Q2, 2009	20.0
2007	"	21.0
2008	Global Investment House	21.8
2009	"	23.1
2010	"	24.5
2011	"	26.0
2012	"	27.6
2013	"	29.3
2014	ECA trend projection	31.1
2015	"	33.0
2016	"	35.0

Year	Source	BCM
2017	"	37.1
2018	"	39.4
2019	"	41.8
2020	"	44.4

6.8 Review of electricity and gas pricing

New and higher electricity charges were applied in Qatar from November 2008 for consumers whose monthly consumption exceeds 4,000 kWh. In addition to the higher charge, non-Qatari government employees and staff of semi government establishments, who were until then exempt from paying domestic electricity and water charges, started to pay at a higher rate of 8 dirhams per kWh (US¢2.2/kWh)[29] where electricity consumption exceeds 4,000 KWh a month. Consumers continue to receive free electricity up to 4,000 kWh per month.

QEWC has long-term take or pay purchase contract with Kahramaa (the sole distributor of water & electricity in Qatar) on a fixed tariff. Also, the company has fixed-price contract with Qatar Petroleum for the supply of gas, which is subject to inflation indexation.[30]

6.9 Legal and regulatory framework

The state-owned Qatar General Electricity & Water Corporation (Kahramaa) was created in 2000. Kahramaa purchases its requirements for electricity and water from private producers and acts as the sole transmitter and distributor at the wholesale and retail level. Kahramaa buys power and water from the IWPPs under 25-year agreements and Qatar Petroleum (QP) supplies the IWPPs with natural gas under long-term contracts.

In May 2000, the Qatari government transferred assets owned by the Ministry of Electricity and Water to the Qatar Electricity & Water Company (QEWC or Kahraba), a semi-public body which is 57% owned by local investors and 43% by the government. QEWC is responsible for adding new electric generating capacity, and is working on several large-scale power projects with foreign companies such as AES and International Power. Kahramaa subsequently sold its power and water desalination plants to QEWC.

Kahramaa is to privatise its power and water transmission and distribution systems. However Qatari nationals currently receive free electricity and water supplies, which poses a significant barrier to complete the privatisation.

[29] 1 dirham = 0.275 US cents

[30] TAIB Research, Qatar Electricity & Water Company. GCC First Reaction Report, March 11, 2009

7 UAE

The power sector is organised in different ways in each of the seven emirates. There are four power authorities in the UAE:

- ❑ Abu Dhabi Water and Electricity Authority (ADWEA);
- ❑ Dubai Electricity and Water Authority (DEWA);
- ❑ Sharjah Electricity and Water Authority (SEWA); and
- ❑ Federal Electricity and Water Authority (FEWA), which is responsible for the other four northern emirates of Ajman, Umm Al Qaiwain, Fujairah and Ras Al Khaimah.

7.1 Energy resources

7.1.1 Gas reserves

UAE's natural gas reserves are projected to last for approximately 150-170 years. According to BP Statistical Review of World Energy (2008), the UAE's proven natural gas reserves were 6.11 trillion cubic meters as of January 1, 2007.

Table 37 Proven natural gas reserves- UAE

Proven reserves	at the end of 1987	at the end of 1997	at the end of 2006
trillion cubic meters	5.68	6.06	6.11

Source: BP Statistical Review of World Energy (2008)

UAE holds the fourth largest proven natural gas reserves in the Middle East after Iran, Qatar, and Saudi Arabia. Proven natural gas reserves are expected to rise to 6.4 TCM by 2011 (see Figure 20).

The largest reserves are located in Abu Dhabi (onshore and offshore). Here, the non-associated Khuff natural gas reservoirs beneath the Umm Shaif and Abu al-Bukhush oil fields rank are among the largest in the world.

Sharjah, Dubai, and Ras al-Khaimah contain smaller reserves of 300 BCM, 112 BCM and 34 BCM, respectively.

Figure 20 Natural gas reserves forecast (TCF)- UAE

Source: Global Research – May 08, GCC Natural Gas Sector – Dawn of the 'gas' era! Global Investment House

7.1.2 Gas production and exports

The majority of UAE gas production is associated gas. During the last ten years, gas production in the UAE has increased rapidly, as shown in Table 38.

Table 38 Natural gas production- UAE

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
BCM	36.3	37.1	38.5	38.4	39.4	43.4	44.8	46.3	47.0	47.4	49.2

Source: BP Statistical Review of World Energy (2008)

The rapid production expansion came, in particular, from:

- Production levels were significantly increased after the completion of the onshore development projects (OGDs), OGD-1 and OGD-2 at the Bab field and AGD-1 (Asab Gas Development) at the Asab field. OGD-3 project further expanded Abu Dhabi Gas Industries Ltd's (GASCO) natural gas production capacity by around 12 BCM in 2008;

- In 2004, an offshore gas production expansion project at the Khuff reservoirs under the Abu Al Bukhoosh field (completed in 2004) increased the volume of gas recovered from the reservoir by some 2 BCM per year.

Total UAE gas production is set to grow steadily as existing field facilities are expanded through to the end of the decade. However, a number of industry commentators have expressed a view that the proximity to the massive North Field in Qatar will make it more economic to import Qatari gas rather than developing the smaller and more complex domestic gas fields. The increasing need for reinjection in oilfields will also limit the expansion of marketed gas.

IMF projections for gas production until 2012 are shown in Table 39.

Table 39 Medium term baseline scenario - UAE

Natural gas production and exports	Est.	Projected (BCM per year)					
	2006	2007	2008	2009	2010	2011	2012
Natural gas production	47.0	48.6	51.1	53.6	56.3	59.1	62.1
LNG exports	7.8	8.0	8.4	8.9	9.3	9.8	10.3
NGL exports	13.7	14.2	14.9	15.7	16.5	17.3	18.1

Source: IMF UAE: Staff Report for the 2007 Article IV Consultation, 2007

Abu Dhabi accounts for more than 80% of the UAE's gas production.

Since the commissioning of the Das Island plant in 1977, the Abu Dhabi Gas Liquefaction Company (ADGAS) has sold LNG to Japan's Tokyo Electric Power Company (TEPCO) under long-term contracts. Under the current contract, ADGAS exports LNG to TEPCO until 2019. ADGAS has also sold LNG on the spot market to Europe, the United States, and South Korea.

Paradoxically, as described in Section 2.3, at the same time, Dubai is planning to build an LNG import terminal to be supplied with LNG by Shell either from Qatar or from outside the region.

7.2 Electricity demand

7.2.1 Historical electricity demand

Electricity demand has been increasing dramatically in the UAE in the last decade, along with peak loads as is shown in Table 40.

Table 40 UAE Historical electricity demand and consumption

Year	Consumption (GWh)	Peak demand (MW)
2003	48.155	10,547
2004	52,066	11,011
2005	54,064	11,461
2006	62,647	12,297

Year	Consumption (GWh)	Peak demand (MW)
2007	74,717	13,294

Source: www.moenr.gov.ae[31]

7.2.2 Electricity demand projections

The UAE Government estimates that the annual peak demand for electricity is likely to rise to more than 40,000 MW by 2020[32], reflecting a cumulative annual growth rate of approximately 9% from 2007 onwards. However, within this forecast, in the immediate future, are some developments of major energy intensive industries (aluminium) that account for a substantial share of the incremental demand. This includes developments by the Abu Dhabi National Oil Company (ADNOC) which require 1,000 MW of generating capacity and the Emirates Aluminium smelter which is due to start in 2010 and will be supplied by its own 2,000 MW power plant. Toward the end of the forecast period shown in Table 41 the growth rate flattens out to below 4.5% per annum.

Table 41 UAE electricity demand projections

Year	Peak demand (MW)
2009	18,593
2010	21,548
2011	24,126
2012	27,323
2013	29,444
2014	31,211
2015	32,814
2016	34,238
2017	35,881
2018	37,394
2019	39,104
2020	40,858

Source: www.moenr.gov.ae

[31] Ministry of Energy of he UAE, Statistical Report 2008 http://www.moenr.gov.ae/assetsmanager/dayocuments/Statisticalpercent20Report.pdf

[32] UAE Yearbok 2008

7.3 Power generation capacity review

The total electricity generating capacity in the UAE was 17,369 MW in 2007[33].

The emirates of Abu Dhabi, Dubai and Sharjah account for 90% of the country's installed capacity. ADWEA accounts for 53% of the Federation's total capacity, followed by DEWA, with 29%. SEWA and FEWA own 11% and 7% respectively (see Table 42).

Table 42 Gross generation capacity 2003-2007 (MW) - UAE

Year	ADWEA	DEWA	SEWA	FEWA	Total
2003	5,530	3,833	1,702	1,152	12,217
2004	7,164	3,833	1,702	1,152	13,851
2005	7,882	3,833	1,902	1,152	14,769
2006	8,312	4,199	2,102	1,252	15,865
2007	8,367	5,448	2,302	1,252	17,369

Source: www.moenr.gov.ae

7.4 Electricity and gas transmission review

7.4.1 Electricity

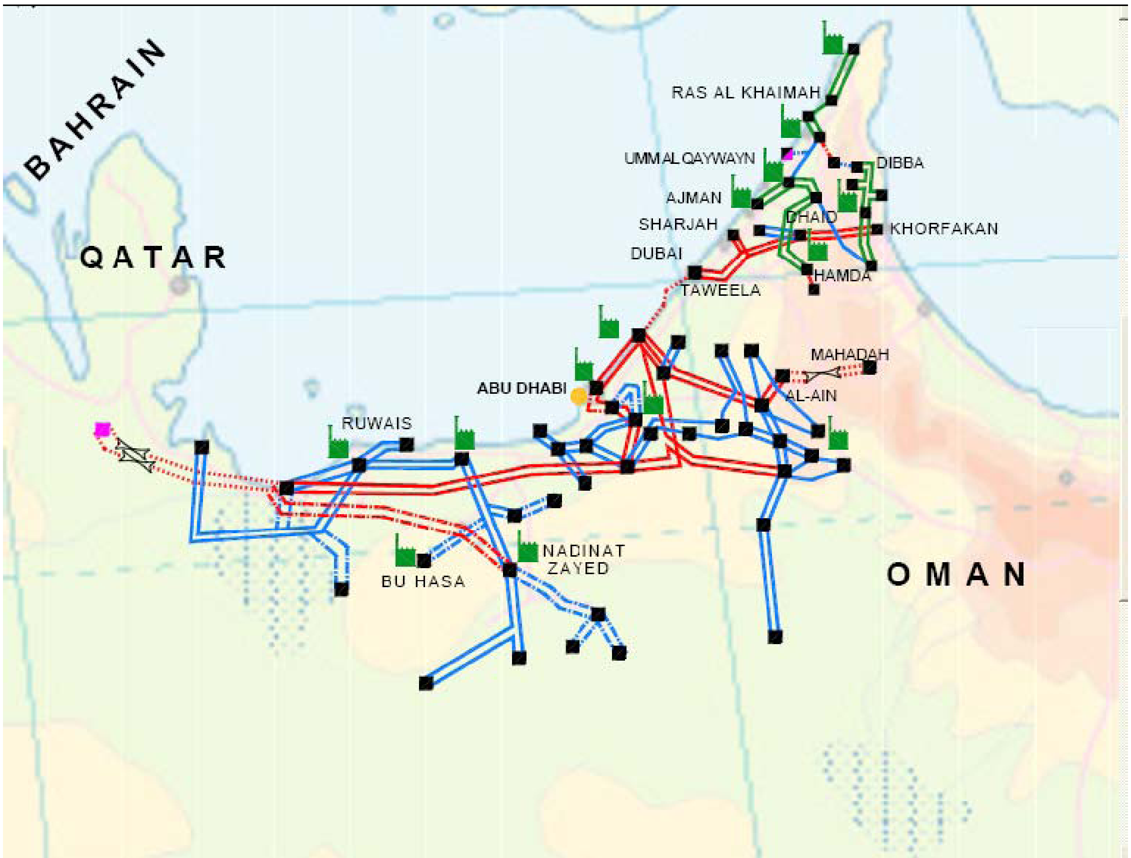
There are four power authorities in the seven emirates comprising the UAE:

- Abu Dhabi Water and Electricity Authority (ADWEA);
- Dubai Electricity and Water Authority (DEWA);
- Sharjah Electricity and Water Authority (SEWA); and
- Federal Electricity and Water Authority (FEWA), which is responsible for the other four northern emirates of Ajman, Umm Al Qaiwain, Fujairah and Ras Al Khaimah.

At present, each service provider operates as a separate entity but a common federal framework for the water and electricity sector is under study by the Ministry of Energy. The electricity network of the UAE is shown in Figure 21.

[33] UAE Yearbook 2008 and *www.moenr.gov.ae*

Figure 21 Electricity map of UAE



Source: http://www.auptde.org. Key: Green 110 kV to 150 kV, Blue 220 kV, Red 300 kV to 400 kV. Dotted lines represent lines planned. Dashed lines represent lines under construction.

Under an agreement signed between Abu Dhabi and the Northern Emirates, Abu Dhabi supplies the five northern emirates with up to 2,500 MW of power for the next seven years.

The GCC interconnection grid allows the UAE to import or export a maximum of 1,300 MW (900 MW to/from Kuwait, Bahrain, Qatar and Saudi Arabia and 400 MW to/from Oman).

7.4.2 Natural gas

UAE has a relatively simple gas network indicated in Figure 22 linking the associated gas from oil fields and non-associated gas with power plants.

Figure 22 Oil and gas resources and supply infrastructure- UAE

Source: IEA World Energy Outlook:, Middle-East and North Africa Insights, 2005

7.5 Supply-demand balance for electricity

The supply-demand balance for electricity is shown in Table 43. The 7.0% required reserve margin is based on the value assumed in the GCC interconnection study (after completion of the GCC interconnection) but this appears very low. The Table suggests that over 26 GW of capacity will be required between now and 2020 in addition to any capacity needed to compensate for plant that is expected to be retired.

Table 43 Electricity supply-demand balance, UAE

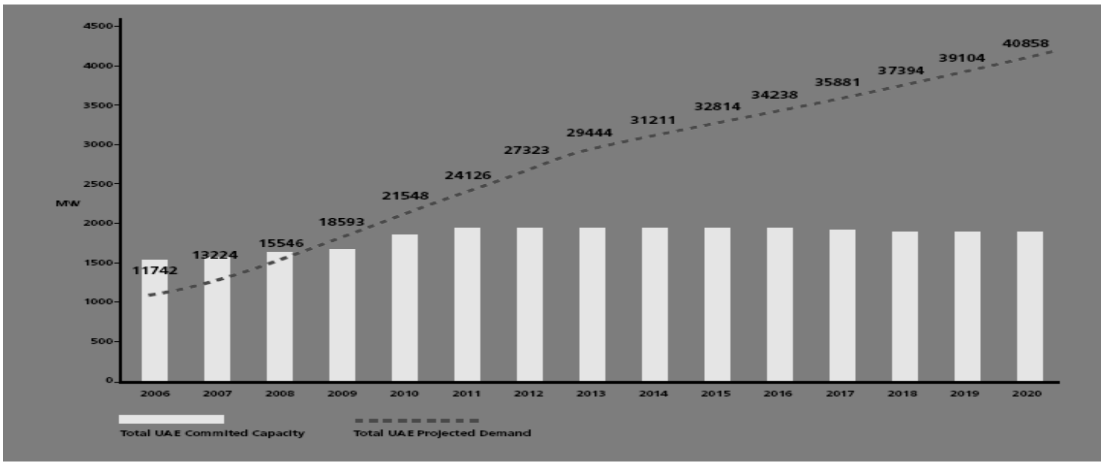
Year	Demand (MW)	Demand + 7.0% reserve margin (MW)	Installed capacity (MW)	Investment required (MW)
2009	18,593	19,895	17369	2,526
2010	21,548	23,056	17369	5,687
2011	24,126	25,815	17369	8,446
2012	27,323	29,236	17369	11,867
2013	29,444	31,505	17369	14,136
2014	31,211	33,396	17369	16,027
2015	32,814	35,111	17369	17,742
2016	34,238	36,635	17369	19,266
2017	35,881	38,393	17369	21,024
2018	37,394	40,012	17369	22,643
2019	39,104	41,841	17369	24,472
2020	40,858	43,718	17369	26,349

7.6 Electricity development plans

Almost 15,000 MW of power generating capacity will be commissioned by 2013, with another 16 000 MW in various stages of planning and bidding[34]. This investment will be needed to meet the fast growing demand (see Figure 23).

[34] UAE Yearbook 2008

Figure 23 Forecast committed electricity generation capacity and demand- UAE



Source: Policy of the United Arab Emirates on the Evaluation and Potential Development of Peaceful Nuclear Energy

About 60% of the total electricity capacity additions will be for new combined water and power plants with desalination units. Almost all new power plants are expected to be gas-fired.

7.7 Demand for natural gas

7.7.1 Historical gas demand

Natural gas consumption reached 43.2 BCM in 2007 (see Table 44)

Table 44 UAE gas consumption

Gas consumption	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
BCM	29.0	30.4	31.4	31.4	32.3	36.4	37.9	40.2	41.3	41.7	43.2

Source: BP Statistical Review of World Energy (2008)

7.7.2 Gas demand projections

Business Monitor International produced a forecast in April 2009, summarised in Table 4. Gas demand is forecast to grow from 43 BCM in 2007 to 67 BCM in 2013. Beyond 2013 we have projected based on BMI's forecast trend rates between 2008 and 2013 of 6.9% per annum.

Table 45 Gas consumption forecast - UAE

Year	Source	BCM
2006	BMI. Bahrain oil and gas report, Q2, 2009	42.0
2007	"	43.0

Year	Source	BCM
2008	"	48.0
2009	"	52.0
2010	"	56.0
2011	"	59.0
2012	"	63.0
2013	"	67.0
2014	ECA trend projection	71.6
2015	"	76.6
2016	"	81.8
2017	"	87.5
2018	"	93.5
2019	"	100.0
2020	"	106.9

7.8 Review of electricity and gas pricing

Each of the four power authorities in the UAE (ADWEA, DEWA, SEWA, and FEWA)[35] , currently operates its own regulatory system and pricing mechanism for electricity.

7.8.1 ADWEA

The Regulation and Supervision Bureau (RSB) implements Annual Price Controls Review system, which includes an annual review of the large-user tariffs[36].

Most customers are supplied with water and electricity by the two distribution companies at one of the standard published tariff rates. All the standard tariffs (see Table 46) are flat rate (do not vary with time of day, season or consumption). They also incorporate a degree of subsidy paid by the Abu Dhabi Government. Existing tariffs are published by the distribution companies. Ultimately all the costs are passed through to the distribution companies from the production companies via ADWEC, using the Bulk Supply Tariff (BST) and from Transco -via the transmission use-of-system charge. The distribution companies in turn pass on these costs and their own costs (distribution use-of-system and sale) to the customer.

[35] Abu Dhabi Water and Electricity Authority (ADWEA), Dubai Electricity and Water Authority (DEWA), Sharjah Electricity and Water Authority (SEWA), and Federal Electricity and Water Authority (FEWA)

[36] For details see http://www.rsb.gov.ae/PDFs/Workplan2009.pdf

Table 46 Standard tariffs for electricity – Abu Dhabi, UAE

Consumer group	Tariff, US cents/kWh
UAE national domestic (remote areas)	3
UAE national domestic (other areas)	5
Ex-pat domestic	15
Commercial	15
Industrial	15
Farms	3

Source: www.rsb.gov.ae

Under one of the terms of their licence the two distribution companies are required to offer special supply terms to large customers - defined as those taking more than 1 MW of peak demand for electricity – referred to as a Non-Standard Connection and a Non-Standard tariff.

Under the Non-Standard tariff arrangements customers have an option to select a flat rate tariff or one linked to the BST. For this latter arrangement, time of day metering is necessary as each unit varies in price over any given month. For the levelised or flat rate tariff the BST component is set at an average price each year.

Electricity customers with consumption in excess of 1 MW may, in certain circumstances, be entitled to Cost-Reflective Large-User Tariffs (see Table 47).

In view of the fact that the standard tariff is set at a subsidised level of 15 fils/kWh[37] (US¢4.09/kWh), such large-user tariffs are only likely to be attractive for customers with relatively low costs resulting from a direct connection to the transmission system and a favourable (flat) load profile.

Given the increase in the number of Large-User Tariff applications received during 2007, the Bureau agreed with Abu Dhabi Distribution Company (ADDC) and Al Ain Distribution Company (AADC) that a common Large-User Tariff may be offered to all customers meeting the above criteria. This structure provides an incentive for customers to manage their demands away from the peak demand period, and thus effectively reduce their tariff. This in turn reduces sector costs incurred in meeting peak demands.

Table 47 Large user tariffs for electricity in 2007- ADWEA, UAE

	Large user tariff , US cents per KWh

[37] 1 fil = 0. 2725 US cents

	Peak: midday- midnight	Off-peak: midnight-midday
Summer (June – Sept.)	3.38	2.73
Winter (October- May)	2.73	2.73

Source: RSB Annual Report 2007

7.8.2 DEWA, SEWA, and FEWA

On 1 March 2008 Dubai Electricity and Water Authority (DEWA) introduced a new tariff structure known as the *slab systems*[38] (see Table 48).

Table 48 Electricity tariffs – DEWA, UAE

Customer Category	Tariff, fils (US cents)/kWh
Residential	
1 to 2000 kWh	20 fils (US¢ 5.45)
2001 to 4000 kWh	24 fils (US¢ 6.54)
4001 to 6000 kWh	28 fils (US¢ 7.63)
6001 kWh and above	33 fils (US¢ 12.12).
Government establishments	
1 to 10,000 kWh	20 fils (US¢ 5.45)
10,001 kWh and above	33 fils (US¢ 12.12).
Industrial	
0 - 10,000 kWh	20 fils (US¢ 5.45)
More than 10,000 kWh	33 fils (US¢ 12.12).

Source: www.dewa.gov.ae

Average individual electricity usage at the time was said by DEWA to be 20,000 kWh per annum, placing Dubai among cities with the highest consumption per person in the world. However, consumers, whether commercial, educational or residential who did not introduce measures to reduce consumption after the

[38] 20 fils for 1 to 2000 Kilowatt Hour (KWh), 24 fils for 2001 to 4000 KWh, 28 fils for 4001 to 6000 KWh, and 33 fils for the 6001 KWh plus slab. For government establishments, the tariff is 20 fils for 1 to 10,000 KWh, and 33 fils for the 10,001 plus slab. For temporary connections a flat rate of 40 fils per KWh is charged.

introduction of the slab tariff will have seen electricity bills in some cases soar by over a million dirhams[39].

Both FEWA and SEWA followed suit, introducing similar tariff structures[40] and rates[41].

7.9 Legal and regulatory framework

At present, each of the four service providers ADWEA, DEWA, SEWA and FEWA operates as a separate entity but a common federal framework for the water and electricity sector is under study by the Ministry of Energy.

Abu Dhabi has one of the more advanced power reform programmes in the region. The Abu Dhabi Regulation & Supervision Bureau is the independent regulatory body for the water, wastewater and electricity sector. It regulates all companies undertaking activities associated with electricity and water production, transmission, distribution and supply. In addition, the Bureau also regulates the wastewater sector which is responsible for ensuring the safe collection, treatment and disposal of wastewater products.

Established in March 1998 by the government of Abu Dhabi to replace the Water and Electricity Department, ADWEA is a public agency owned by the Abu Dhabi government but with a separate legal identity and with financial and administrative independence. ADWEA is the holding company for the unbundled electricity sector and is owner of the electricity and water transmission company (TRANSCO), two electricity and water distribution companies, two of the emirate's generation companies and the single buyer – the Abu Dhabi Water and Electricity Company (ADWEC). In addition to its main activities, ADWEA develops, implements, and manages the water and electricity policies and procedures that are carried out by its subsidiaries.

Five IWPPs have been introduced on a build, own and operate (BOO) basis via joint venture arrangements between ADWEA and various international companies. In each IWPP, ADWEA holds a 60% share holding while the remaining 40% is owned by overseas private investors. All IWPPs sell water and electricity from their production plant to the single buyer (ADWEC) under long-term agreements.

Abu Dhabi is the only emirate to implement a privatisation programme in UAE in electricity sector. It is also the only emirate to have separated network activities from power generation. Transmission is handled by TRANSCO, while distribution

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[39] A survey, based on actual buildings, shows a Dubai office tower of around 35,000 square metres on Sheikh Zayed Road, which had a previous annual electricity bill of US$680,000, with an increase over the past year of 65% to US$1.2 million. "Dubai electricity costs soar 66% in one year". http://www.aeconline.ae/13/pdcnewsitem/01/60/12/index_13.html

[40] Emirates raise tariffs in line with Dubai, published: 20 March 2008 17:20

[41] Khaleej Times 2008, http://www.zawya.com/story.cfm/sidZAWYA20080406040529/Sharjah%20Electricity%20and%20Water%20Authourity%20launches%20slab%20tariff%20system

is divided between the Abu Dhabi Distribution Company (ADDC), which covers the old municipality region of Abu Dhabi including Al Gharbia (the Western Region), and the Al Ain Distribution Company (AADC), which covers the old municipality region of Al Ain.

Dubai, along with all other GCC states other than Kuwait, has is also introduced the IWPP model for new generation. It is also planning to reform and restructure its power sector in a way similar to that of Abu Dhabi.

The Federal National Council, which is UAE's governing body, has recently approved a plan to privatise the assets of FEWA, providing a clear signal that, as was done with ADWEA, it wants to attract private power and water investment into its poorer northern regions.

8 Oman

8.1 Energy resources

8.1.1 Proven gas reserves

Over the past decade, proven gas reserves have risen steadily, standing at around 0.69 BCM at the end of 2006.

Table 49 Proven natural gas reserves - Oman

Proven reserves of natural gas	at the end of 1987	at the end of 1997	at the end of 2006
trillion cubic meters	0.27	0.54	0.69

Source: BP Statistical Review of World Energy, June 2008

The number of non-associated gas fields during 2007 was 14, out of which 5 fields belonged to Petroleum Development Oman (PDO) and 7 to Occidental Oman Company, and one each to Rak Petroleum and BTT Oman.

For hydrocarbons, Oman's geology is different from that of Saudi Arabia and the UAE. Omani fields are small, deep and more complex, with many having low permeability. The wells in Oman are in very tight reservoirs down to depths of up to 5,000 metres. The gas has condensate so it is high pressure and high temperature. There are very few of these kinds of wells in the world today.

The main oil and gas producing areas of Oman (see Figure 25, Section 1.1.1) include the following[42]:

- ❑ Arabian Basin, linked to that of the UAE and Saudi Arabia;
- ❑ Oman Salt Basin in the centre and south; and
- ❑ A narrow strip of offshore territory facing the western coast of the Musandam Peninsula.

Within onshore Oman there are four oil areas:

- ❑ In the north the crude is light and normally recovered with gas. The most northerly oil area lies close to the borders with Abu Dhabi, and Saudi Arabia, in the extension of the Arabian Basin. The three main fields there are Lekhwair, Safah and Daleel. Their oil and gas reservoirs

[42] OMAN: The Geology. Publication: APS Review Gas Market Trends. February 2004 http://www.accessmylibrary.com/coms2/summary_0286-20177521_ITM

are of the Thamama group similar to that of eastern Abu Dhabi. Field sizes are small compared to the great Thamama field of Abu Dhabi.

- South of the Lekhwair-Daleel there are three productive areas in central and southern Oman. In the north of these areas are oil and associated gas fields centred on Fahud-Natih-Shibkah (Yibal).

- In central Oman, a group of fields is centred on Saih Nihaydah. Field sizes for oil are small. But since late 1989 drilling at Saih Nihayadah and nearby fields has led to the discovery of a deeper gas/condensate pool with very large reserves.

- In east-central Oman, the Barik and Saih Rawl fields have fairly large reserves of oil and gas.

- In the south there is little gas associated with oil. Marmul oil, found in 1956, was then considered uneconomical because of its quality (high sulphur content). Advanced technology makes oil extraction at Marmul possible. Some fields in the southern trend also have natural gas. Due to the lack of infrastructure in this area, however, companies are not interested in gas bearing blocks on offer.

The government plan is to find more gas so that the proven reserves may reach 1.4 trillion cubic meters by 2010[43]. Whether or not Oman is able to significantly increase natural gas production in the future hinges on the successful development of "tight" natural gas reservoirs, which are geologically complex structures considered much more difficult to access than conventional natural gas reserves. In particular:

- The Khazzan/Makarem tight natural gas fields were originally discovered in 1993, but have remained undeveloped. In January 2007, BP signed a Production Sharing Contract (PSC) for Khazzan/Makarem, and is carrying out appraisal work to judge the fields' potential. According to BP the two fields could potentially yield between 0.56 trillion cubic meters and 0.84 trillion cubic meters.

- Another tight natural gas project with large potential is the Abu Butabul field, for which BG signed a PSC in 2006. According to BG the field holds probable natural gas reserves of 0.14- 0.22 trillion cubic meters, although advanced seismic and drilling tests are not expected to be completed until mid-2007.

It is expected that al-Noor-2 and the newly discovered gas field - Simr - may provide significant new oil and gas reserves.

In early 2009 Oman signed gas exploration and sales deals with European major BP and Malaysia's state-owned Petronas and awarded an exploration and production sharing agreement (EPSA) to US-based Harvest Natural Resources for the E&P of non-associated gas and condensate in the Al Ghubar / Qarn Alam licence. This is

[43] Source: PDO Oman

Oman's latest move to try to develop its gas reserves as part of its economic diversification strategy. Intensive gas exploration activity has more than doubled proven reserves in recent years. Gas reserves are believed to have upside potential of around 790 BCM by 2013.

8.1.2 Gas production

Expanding natural gas production had been a chief focus of Oman's strategy to diversify its economy away from petroleum.

Table 50 Gas production - Oman

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007 est
BCM	5.0	5.2	5.5	8.7	14.0	15.0	16.5	18.5	19.8	23.7	34.1

Source: BP Statistical Review of World Energy, June 2008

Government sources indicate different figures for the production of natural gas at around 30.0 BCM in 2007 (see Table 51) with 6.1 BCM of associated gas and 23.9 BCM non-associated gas. Table 51 indicates 29.5 BCM in 2006 compared with BP's figure of 23.7 BCM. Government figures indicate:

- 0.87 BCM of natural gas (ie., only around 3% of total gas production) was exported to UAE. The remaining 97% of natural gas was used for LNG production and exports, in domestic industries, as well as oil fields.
- Oman LNG and Qallat LNG are consuming a major chunk, around 42% of natural gas to produce LNG for exports. During 2007 LNG exports amounted to 12.6 BCM, unchanged from 2006. LNG was exported to Korea, Japan, China, Taiwan and India.
- At present, besides the use for LNG trains, gas is largely utilised for re-injection into the oil reservoirs to maintain pressure and sustain oil production (9.3% in 2007).
- An increasing part of the natural gas is being used as fuel to generate power, and in desalination plants (6.8% in 2007)
- Gas is increasingly used also in the industrial sector, eg., cement factories and other industrial projects. Rising natural gas production over the last several years has resulted in the expansion of natural gas-based industries, such as petrochemicals.

Table 51 Gas production and consumption – Oman			
	2006	**2007**	**Percent change 07/06**
Production , BCM	29.5	30.0	1.8
Associated	6.6	6.1	-6.5
Non – associated	22.9	23.9	4.2
Consumption, BCM	29.5	30.0	1.8
Government gas system	6.7	7.6	12.8
OLNG	10.1	9.9	-2.0
QLNG	3.4	3.9	13.6
Exported (UAE)	1.3	1.0	-27.3
Oil fields	4.6	4.8	4.6
- Fuel	1.9	2.0	5.0
- Reinjection	2.7	2.8	4.3
Flared	1.4	1.4	-2.0
Other	1.9	1.5	-21.5

Source: Central Bank of Oman, Annual report 2007. Original source: Ministry of National Economy

Recent developments include:

- In February 2007, PTTEP started commercial production at the Shams field in Block 44 at an initial rate of 1.5 MCM per day;
- Kauther gas field and its associated processing plant were commissioned in 2008. The processing station has the capacity to produce 19.6 MCM.

8.2 Electricity demand

8.2.1 Historical electricity demand

Electricity demand has been growing at a compound average growth rate (CAGR) of 6.9% over the period 2002-2007 and stood at 14,443 GWh in 2007 (see Table 52).

Table 52 Historical electricity generation and sales - Oman							
	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Generation, GWh	9,737	10,331	10,714	11,499	12,648	13,585	14,443
Sales, GWh	9,178	9,851	10,303	10,959	12,023	13,127	13,856

Source: Ministry of Economy, Oman

8.2.2 Electricity demand projections

Table 53 below shows projections of demand for electricity (maximum demand and energy) for the two main public systems in Oman: the Main Interconnected System (MIS) and Salalah. The highlights are as follows:

- The maximum power demand in the MIS is expected to grow from 3,031 MW in 2008 to 5,348 MW by 2015, an average increase of around 8.5% or 330 MW per year. Annual energy demand is expected to grow similarly, from 14.0 TWh in 2008 to 25.6 TWh in 2015;
- In the Salalah System, the maximum demand is expected to grow from 260 MW in 2008 to 552 MW by 2015, an average annual increase of around 11% or 40 MW per year.

Table 53 Expected power and energy demand - Oman

	2008	2009	2010	2011	2012	2013	2014	2015	2020	Avg.
MIS										
Peak demand (MW)[44]	3,031	3,371	3,739	4,220	4,507	4,742	4,984	5,348	8,042	8.5%
Energy (TWh)	14,02	15.84	17.64	20.09	21.56	22.62	23.77	25.60	39.39	9.0%
Salalah										
Peak demand (MW)	260	305	349	427	458	492	523	552	947	11.4%
Energy (TWh)	1.47	1.73	2.00	2.48	2.68	2.87	3.05	3.23	5.62	11.7%
Total										
Peak demand (MW)	3,291	3,676	4,088	4,647	4,965	5,234	5,507	5,900	8,954	8.7%
Energy (TWh)	15.49	17.58	19.64	22.57	24.24	25.49	26.82	28.82	44.96	9.3%

Source: Oman Power and Water Procurement Company (OPWP) - year Statement (2009-2015). Extended from 2015 to 2020 using average growth rates from 2008-2015.

The above figures exclude the demand on the PDO grid which may account for as much as half of Oman's total electricity demand.

[44] Includes an. extension of the MIS to Ad-Duqm with a load of 90 MW.

8.3 Power generation capacity review

Generating capacity in Oman in 2008 included 3,319 MW connected to the MIS system including non-firm capacity from contracted plants and surplus generation from industry. There was a further 326 MW connected to the Salalah system comprising a new plant with 207 MW of gas turbines, an older plant with 49 MW of re-commissioned gas turbines, and the Raysut A&B diesel plant with 70 MW of capacity.

Table 54 Generation capacity (2008) – MIS, Oman

	Technology	Available capacity MW
Al- Ghubrah power and desalination plant	CCGT	478
Rusail power plant	Open-cycle gas turbines	684
Wadi Al—Jizzi power plant	Open-cycle gas turbines	287
Manah Power plant	Open-cycle gas turbines	279
Al-Kamil Power plant	Open-cycle gas turbines	282
Barka 1 power and desalination plant	CCGT	454
Sohar power and desalination plant	CCGT	605
Surplus capacity from industry		250
Total capacity available to OPWP		**3,319**

Source: OWPS 7 year Statement (2009-2015), p.12-13 and p. 31

In addition to the main grid supplied consumers, there are also other companies that produce power for their own needs, including the Oman Mining Company, Oman Cement Company, Sohar Refinery, Sohar Aluminium Company, Ministry of Defence and Occidental of Oman.

8.4 Electricity and gas transmission review

8.4.1 Electricity

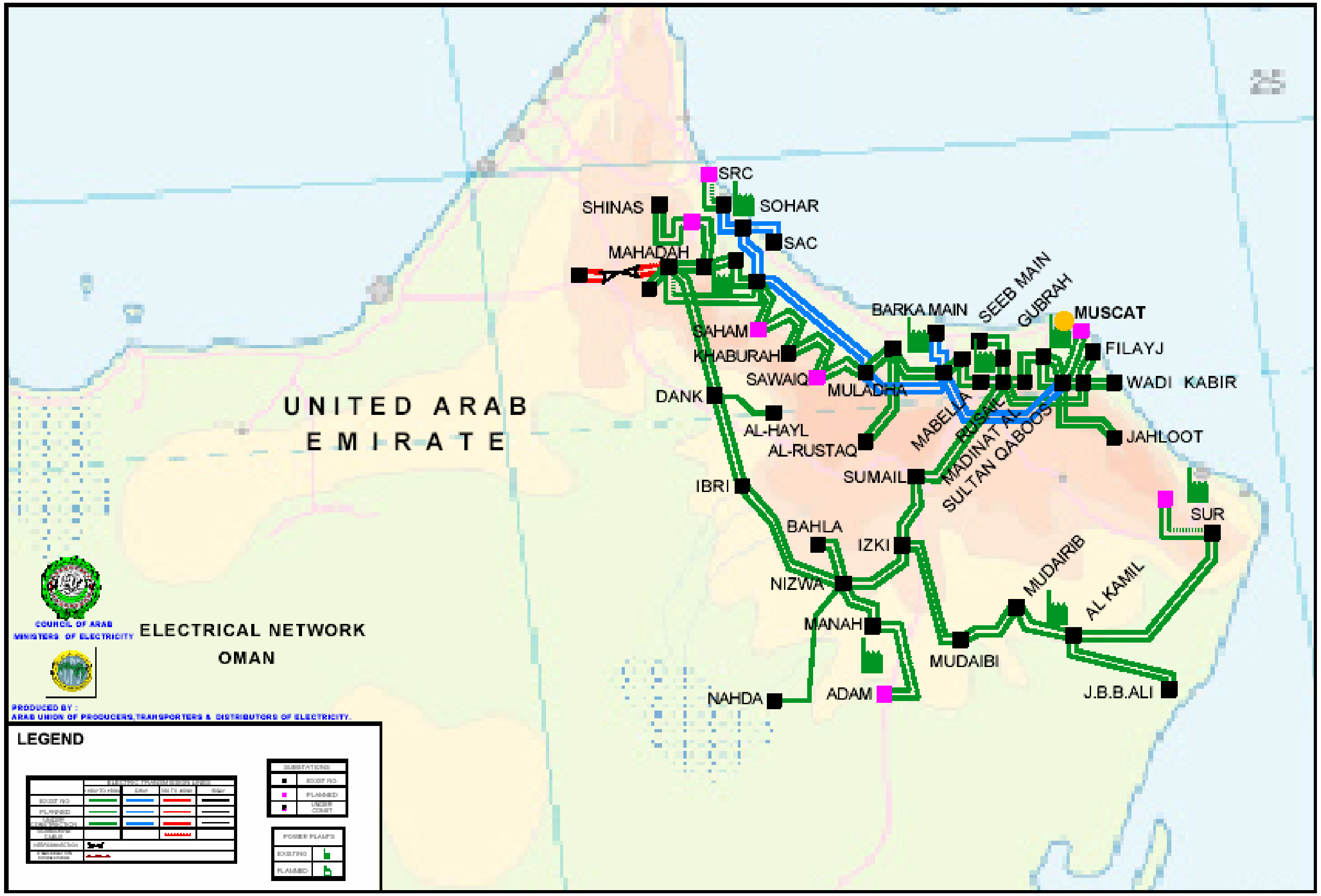
The electricity supply industry in Oman is divided into the following three main groups:

- **The main interconnected system (MIS)** serves the majority of Oman's population (almost 500,000 consumers) covering about 90% of the total electricity supplied in the Sultanate. The system interconnects seven main power plants using a network of 220 kV and 132 kV transmission lines.
- **The Salalah system** with voltage levels of 33 kV and, more recently, 132 kV covers Salalah and surrounding areas in the Dhofar region, south of Oman, serving around 50,000 consumers.

- **The Rural Areas Electricity Company SAOC (RAEC)** operates in areas where the transmission network of the MIS network does not currently exist, and includes the Musandam, Al Wusta and Dhofar regions.

- **Petroleum Development Oman (PDO)**, the main oil company in Oman has its own dedicated network comprising 2,400 km of 132 kV lines together with a large network of 33 kV lines. In addition to supplying its own needs it also sells electricity to RAEC.

Figure 24 Oman electricity map – Main Interconnected System



Source: http://www.auptde.org

The MIS is currently interconnected with the PDO power system by a 132 kV line with a capacity of 100 MW and, since 2006, with Abu Dhabi via a 220 kV link – forming part of the wide GCC interconnect, as described in Section 2. The GCC arrangement allows an exchange of 400 MW with UAE.

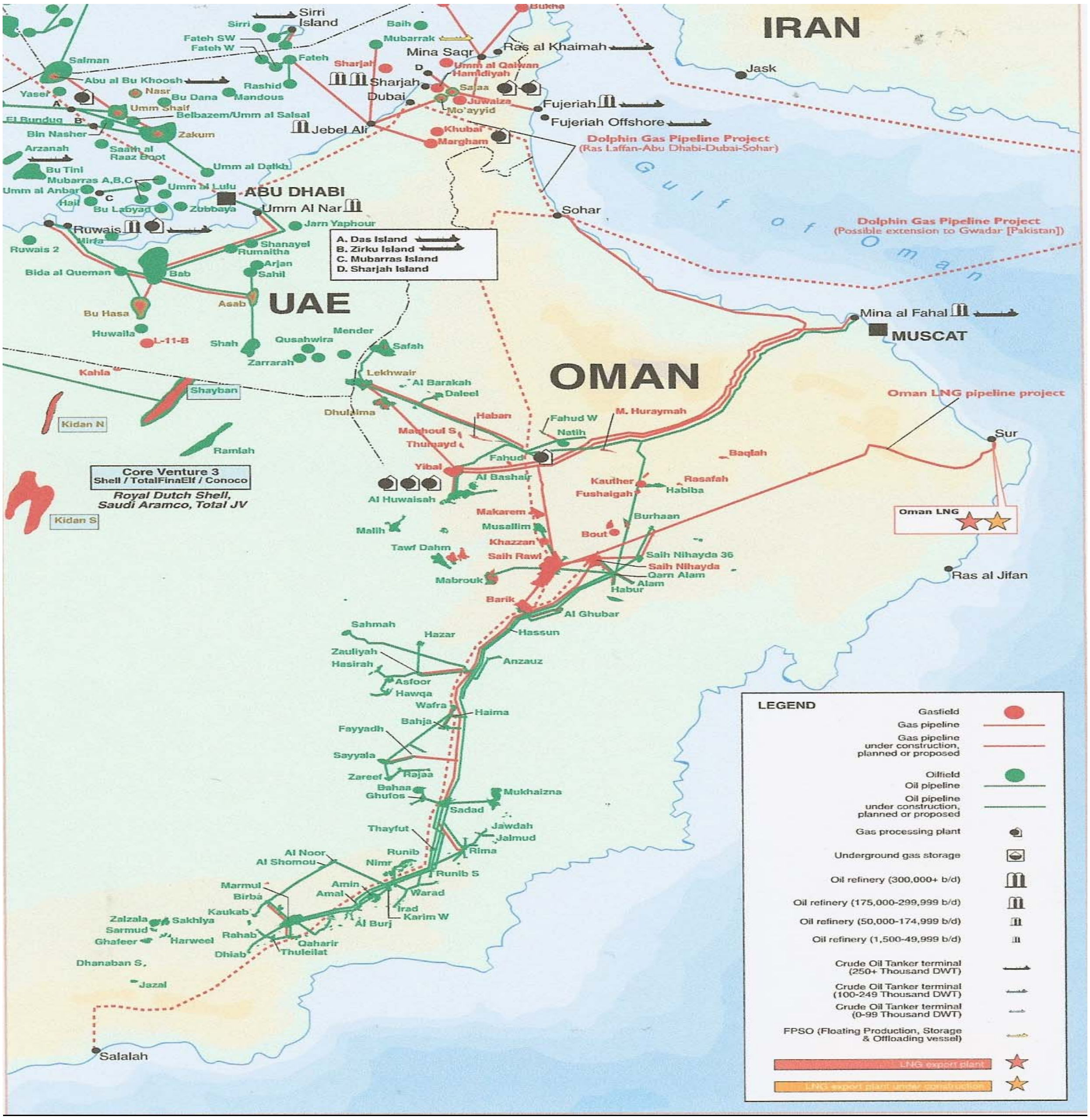
8.4.2 Natural gas

Petroleum Development Oman (PDO) is the leading player in the upstream natural gas sector in Oman but foreign companies such as Indago Petroleum, Occidental Petroleum, and Thailand's PTTEP also have a share of the upstream market. The Oman Oil Company (OOC) directs state investment in downstream projects through such subsidiaries as Oman Gas Company (OGC). Oman's domestic natural gas pipeline system is controlled by the OGC, although OGC has contracted the management of the network to a consortium of private companies. LNG activities are primarily carried out by the Oman Liquefied Natural Gas Company (OLNGC).

Oman's natural gas network spans about 1,760 km, bringing supplies from production centres to the country's LNG terminals, power plants, and other domestic end users. PDO is responsible for delivering gas to the advanced LNG export plant near Sur. The gas comes mostly from the Natih gas reservoir of the Yibal field.

Oman exported natural gas to the UAE via two pipelines. One 45 km pipeline, Suhar to Buraimi, sent approximately 1.7 BCM to a power plant in the UAE, but the flow was reversed starting in 2008 when Qatari natural gas through the Dolphin line became available. A second line of 300 km in length became operational in 2004, transported gas from Fahud to Sohar, before continuing through al Buraimi to Al Ain to UAE. The pipeline fed 0.5 BCM of Omani gas to UAE until 2007 when the flow was also reversed after gas from Dolphin became available in 2008.

Figure 25 Oil and gas map of Oman



Source: Petroleum Economist, World Energy Atlas 2004, www.petroleum-economist.com

8.5 Supply-demand balance for electricity

The supply-demand balance for electricity is shown in Table 55. The 8.2% required reserve margin is based on the value assumed in the GCC interconnection study (after completion of the GCC interconnection) but this appears very low. OPWP itself plans to install capacity to give a reserve margin closer to 13% to give a LOLE[45] of 24 hours per year. The Table suggests that over 6,000 MW of capacity will be

[45] Loss of Load Expectation – a measure of system security.

required between now and 2020 in addition to any plant scheduled for retirement. As described in Section 8.6 below, 2,800 MW of capacity is under development or is planned.

Table 55 Electricity supply-demand balance, Oman

Year	Demand (MW)	Demand + 8.2% reserve margin (MW)	Installed capacity (MW)	Investment required (MW)
2009	3,676	3,977	3,319	658
2010	4,088	4,423	3,319	1,104
2011	4,647	5,028	3,319	1,709
2012	4,965	5,372	3,319	2,053
2013	5,234	5,663	3,319	2,344
2014	5,507	5,959	3,319	2,640
2015	5,900	6,384	3,319	3,065
2016	6,413	6,939	3,319	3,620
2017	6,971	7,543	3,319	4,224
2018	7,578	8,199	3,319	4,880
2019	8,237	8,912	3,319	5,593
2020	8,954	9,688	3,319	6,369

8.6 Electricity development plans

Planned generating capacity over the period to 2015 for the MIS and Salalah systems is shown in Table 56 and Table 57 respectively.

Table 56 Generation capacity (MW) – MIS, Oman

	2008	2009	2010	2011	2012	2013	2014	2015
Total existing, contracted and planned	3,029	3,725	3,612	3,611	3,540	3,457	3,402	3,402
Total non-contracted capacity	290	290	401	401	471	471	525	525
Total capacity available to OPWP	3,319	4,015	4,013	4,012	4,011	3,928	3,923	3,923

Source: 7 year Statement (2009-2015)

Table 57 Generation capacity (MW) – Salalah system, Oman	2008	2009	2010	2011	2012	2013	2014	2015
Raysut New Power Station (NPS) DPC	256	256	256	256	256	256	256	256
Raysut A&B diesels (RAEC)	70	65	65	65				
Total	326	321	321	321	256	256	256	256

Source: 7 year Statement (2009-2015)

According to OPWP additional power generation requirements are as follows (see Table 58):

- Between 2,100 MW and 3,000 MW of additional power generation resources are needed for the MIS by 2015;
- Between 320 MW and 470 MW of additional power generation resources are needed for the Salalah System by 2015. All or most of this will ultimately be provided by the Salalah IWPP. However, up to 65 MW of additional power generation is required on a short-term basis by 2010, prior to the anticipated availability of early power of the Salalah IWPP;
- Additional capacity requirement is around 2,420 MW for the "expected" demand scenario.

Table 58 Additional generation required, Oman	2009	2010	2011	2012	2013	2014	2015
MIS							
For *expected* demand (MW)	-	150	650	1,100	1,400	1,700	2,100
Salalah							
For *expected* demand (MW)	-	40	120	230	270	290	320

Source: OPWP 7 year Statement (2009-2015)

The procurement Strategy adopted by OPWP for 2009 includes:

- Two new "green-field" gas-fired IPPs, located at Barka and Sohar, each having a capacity of around 650 MW. These are expected to provide up to 750 MW of early power from 2011 and be fully commissioned by 2012;
- Expansion/redevelopment of the Al -Ghubrah Power and Desalination Plant, including a new gas-fired IWPP providing additional power capacity of up to 500 MW, to be available from 2013 and located on part of the site presently occupied by Al-Ghubrah Power and Desalination Company SAOC (GPDC), combined with integration of existing assets

to be acquired from GPDC and addition of new desalination capacity of 136,000 m^3 per day; and

- A new "green-field" I(W)PP, located at Ad-Duqm, with a capacity of 1,000 MW. There is a possibility that this I(W)PP may be coal fired. This I(W)PP is expected to be completed in phases in 2015 and 2016 with the first phase providing up to 500 MW in 2015.

OPWP is pursuing and/or considering a number of additional options to address short-term generation requirements in the Salalah System prior to 2011, including:

- fast- track completion of interconnect with PDO system, tapping surplus generation resources available in the PDO system and/or the MIS;
- enhancement of the capacity of the Raysut NPS gas turbines by DPC; and
- temporary generation based on gas or diesel engine rental.

Ongoing procurement process for 370-430 MW and 68,000 m^3 per day Salalah IWPP is expected to be completed during the first half of 2009, with a view to securing full availability of the plant by first quarter of 2012. Up to 200 MW of "early power" may be secured for summer 2011.

OPWP plans also to pursue options for procurement of additional generation for the MIS, to meet the evolving demand scenario requirements of 2013 and 2014, supplement capacity provided by IWPPs and/or provide fuel efficiency benefits, including through conversion of existing open-cycle gas turbine capacity to combined cycle.

8.7 Demand for natural gas

Oman produced 21.7 BCM of natural gas in 2007 but about half is exported as LNG. The level of local gas consumption in Oman was 12 BCM in 2007[46].

Table 59 shows the forecasts for annual consumption of natural gas for the two main systems: MIS and Salalah. These were extended to 2020 by the Consultant based on trends between 2010 and 2015.

Table 59 Gas demand projections (BCM) - Oman

Year	MIS	Salalah	Total
2009	4.9	0.5	5.4
2010	5.3	0.6	5.9
2011	5.9	0.8	6.7

[46] Source: *BP Statistical Review of World Energy*, June 2008

Year	MIS	Salalah	Total
2012	6.2	0.6	6.8
2013	6.1	0.7	6.8
2014	6.4	0.7	7.1
2015	6.8	0.8	7.6
2016	7.1	0.8	8.0
2017	7.5	0.9	8.4
2018	7.9	1.0	8.8
2019	8.3	1.0	9.3
2020	8.7	1.1	9.8

Source OPWP 7 year Statement (2009-2015). Extended to 2020 by the Consultant.

8.8 Review of electricity and gas pricing

8.8.1 Electricity

Table 60 shows electricity tariffs in Oman in 2007. These, according to the Sector Law are approved by the Council of Ministers.

The electricity supply tariff for industrial entities is 12 baiza (US¢ 3.13)[47] per kWh from September to April, and 24 baiza (US¢ 6.26) per kWh during May to August.

The Permitted Tariffs shown in Table 60 do not provide sufficient revenue to cover the full economic cost of electricity supply, so subsidies are required to sustain the electricity sector's operations. The Sector Law implements a mechanism through which the Ministry of Finance provides a subsidy, as calculated by the Authority, to licensed suppliers on an annual basis. A subsidy is provided only to the four licensed suppliers: Muscat, Majan and Mazoon Discos and RAEC.

Table 60 Electricity tariffs (2007) - Oman

Group	Tariff				
Industrial	Dhofar region Aug. – March: 12 Bz (US¢3.1)/kWh Apr. – July: 24 Bz (US¢6.3)/kWh			All other regions Sep. – Apr: 12 Bz (US¢3.1)/kWh May. – Aug: 24 Bz (US¢6.3)/kWh	
Commercial	20 Bz (US¢5.2)/kWh				
Defence	20 Bz (US¢5.2)/kWh				
Residential & Government	0-3,000	3,001-5,000	5,001-7,000	7,001-10,000	10,000+

[47] 1 baiza = US¢ 0.2604

blocks (kWh)					
(Bz/kWh)	10 (US¢2.6)	15 (US¢3.9)	20 (US¢5.2)	25 (US¢6.5)	30 (US¢7.8)
Agriculture & fisheries blocks (kWh)	0-7,000	7,001+			
(Bz/kWh)	10 (US¢2.6)	20 (US¢5.2)			
Tourism blocks (kWh)	0-3,000	3,001-5,000	5,001-7,000	7,001+	
(Bz/kWh)	10 (US¢2.6)	15 (US¢3.9)	20 (US¢5.2)	20 (US¢5.2)	

Source: Oman Authority for Electricity Regulation, 2007 Annual Report

The Sector Law anticipates the introduction of cost reflective tariffs, which do not include any element of subsidy and reflect only the actual cost of supply. The Oman Authority for Electricity Regulation recommended the implementation of these tariffs for industrial customers from 1 January 2007 but they have not been implemented as yet.

8.8.2 Gas

The price of plant gas being charged by the state-owned Oman Gas Company for industries of strategic importance was US$0.80/mmbtu in 2008.

8.9 Legal and regulatory framework

Policy making responsibility in the power sector in Oman rests with the Ministry of Water and Electricity while the regulatory functions lie with the Authority for Electricity Regulation (AER).

Oman was the first GCC country to introduce the IPP and IWPP models and has successfully privatised, or offered its new plants for private investment, most of its power plants beginning with Manah Phase 1 in 1996 and Manah Phase 2 in 1999, the Al Kamil IPP and Barka IWPPprojects in 2000, the Salalah Concession Agreement in 2001 and the Sohar IWPP in 2004.

There remain two state-owned power generation companies:

- Wadi Al- Jizzi Power Company, and
- Al-Ghubrah Power & Desalination Company

The Oman Electricity Transmission Company, responsible for development and maintenance of the transmission network and for the transportation of electricity, is also state-owned. The Oman Power & Water Procurement Company, also state-owned, is the “single buyer” of electricity from generators and seller of electricity to the distribution companies and large consumers.

Three distribution and supply companies are:

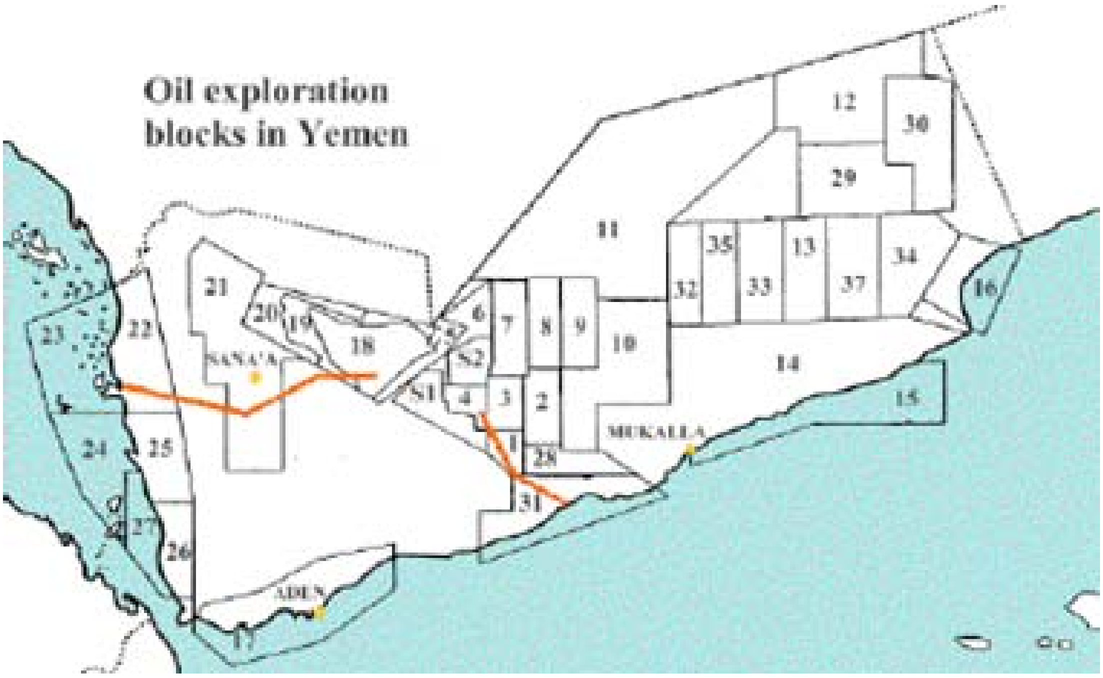
- ❑ Muscat Electricity Distribution Co (MEDC),
- ❑ Mazoon Electricity Co. (MZEC), and
- ❑ Majan Electricity Co (MJEC)

9 Yemen

9.1 Energy resources

An oil concession map for Yemen is shown in Figure 26. Gas reserves are all associated with oil and are primarily located in Blocks 18, 5, S1, S2 and 20. Estimates of reserves in each block are shown in Figure 26.

Figure 26 Oil concession map – Yemen



Source: www.al-bab.com

Information provided by Yemen's Ministry of Oil and Minerals indicates the gas reserves shown in Table 61. This implies that there are 432 BCM of proven reserves in Blocks 5, S1, S2 and 20 and up to 171 BCM available for domestic use after the demand for LNG has been satisfied with 260 BCM (9.2 tcf) from Block 18. The estimates of proven reserves have not been verified.

Table 61 Recent estimates of gas reserves (BCM)

Block	Certified reserves	Proven reserves
18	289	367
5	31	31
S1	0	14

Block	Certified reserves	Proven reserves
S2	0	13
20	0	8
Total	320	432

Source: Letter from Ministry of Oil and Minerals to the Ministry of Finance, January 2009

9.2 Electricity demand

9.2.1 Historical electricity demand

Historical electricity generation and peak demand, adjusted for load shedding, is shown in Table 62. Though adjusted for load shedding, demand was also suppressed by discouraging connections and encouraging customers to use their own generation at peak times.

Table 62 Historical electricity demand - Yemen

Year	Generation (GWh)	Peak demand (MW)
1998	2,556	397
1999	2,735	430
2000	2,960	477
2001	3,169	498
2002	3,281	514
2003	3,507	573
2004	3,707	598
2005	4,057	463
2006	4,275	519
2007	4,402	832

Sources: Ma'rib power project, 2nd stage, Study Final Report, Fichtner for the Ministry of Electricity and Public Electricity Corporation, January 2006 and *PEC Grid Annual Report* 2006.

9.2.2 Electricity demand projections

Projections of unconstrained electricity demand are shown in Table 63.

Table 63 Forecast electricity demand - Yemen

Year	Generation (GWh)	Peak demand (MW)
2009	9,106	1,485

Year	Generation (GWh)	Peak demand (MW)
2010	9,903	1,615
2011	10,504	1,713
2012	10,357	1,819
2013	11,007	1,933
2014	11,610	2,039
2015	13,945	2,449
2016	14,616	2,567
2017	15,323	2,691
2018	16,063	2,821
2019	16,843	2,958
2020	17,663	3,102

Sources: Ministry of Electricity and Energy.

9.3 Power generation capacity review

The capacity of Yemen's main power grid is shown in Table 64. The Ma'rib I power plant is expected to be commissioned in the late summer of 2009 and will add 341 MW of capacity of the network. PEC is also buying power from 210 MW of mobile diesel plants. Other smaller networks are not included in Table 64.

Table 64 Power generating capacity (2009) - Yemen

Plant	Commission year	Fuel	Nameplate capacity	Available capacity
Ras Katenib	1981	HFO	150	120
Al Mocha	1985	HFO	160	140
Hiswa	1986	HFO	125	75
Hiswa 2	2008	HFO	60	60
Al Mansoura	1982	Diesel	64	45
Al Mansoura 2	2006	Diesel	70	70
Khor-Maksar	2003	Diesel	18	18
Dhaban1	1980	Diesel	21	10
Dhaban2	2000	Diesel	30	20
Al Hali & Kornish	1980	Diesel	5	5
Al Hali 2	2003	Diesel	10	10
Sana'a	1972	Diesel	10	10
Sana'a (Wartsila)	2004	Diesel	5	5

Plant	Commission year	Fuel	Nameplate capacity	Available capacity
Osaifirah	2003	Diesel	10	10
Ja'ar	1981	Diesel	2	2
Ja'ar 2	2006	Diesel	4	4
Hiziaz 1	2003	Diesel	30	25
Hiziaz 2	2004	HFO	70	68
Hiziaz 3	2007	HFO	30	30
Ma'rib 1	2009	Gas	341	341
Total			1,215	1,068

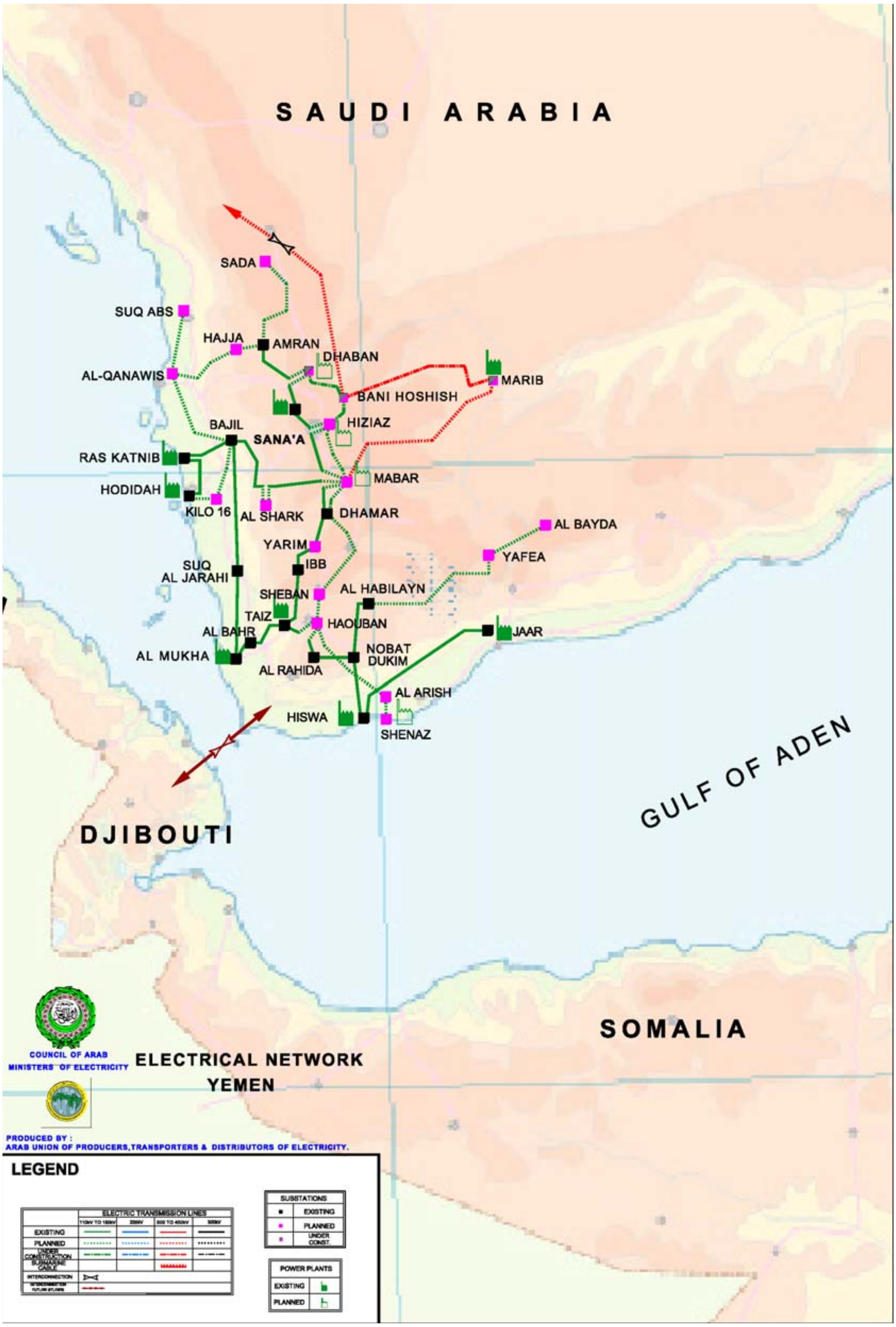
Source: Ministry of Electricity and Energy and Public Electricity Corporation.
Note: Nameplate capacity for older diesel plant is not accurate. Ma'rib 1 had not been commissioned at the time the report was prepared but was expected to be commissioned in July 2009.

9.4 Electricity and gas transmission review

9.4.1 Electricity

Yemen has one main 132 kV grid as shown in Figure 27. A new gas-fired power plant currently under commissioning at Ma'rib, to the east of Sana'a will shortly be connected to the main grid via a 400 kV double circuit transmission line at Bani Hoshish. A second 400 kV transmission line is also planned from Ma'rib to connect to the 132 kV substation at Dhamar, south of Sana'a.

Figure 27 Yemen's main electricity grid



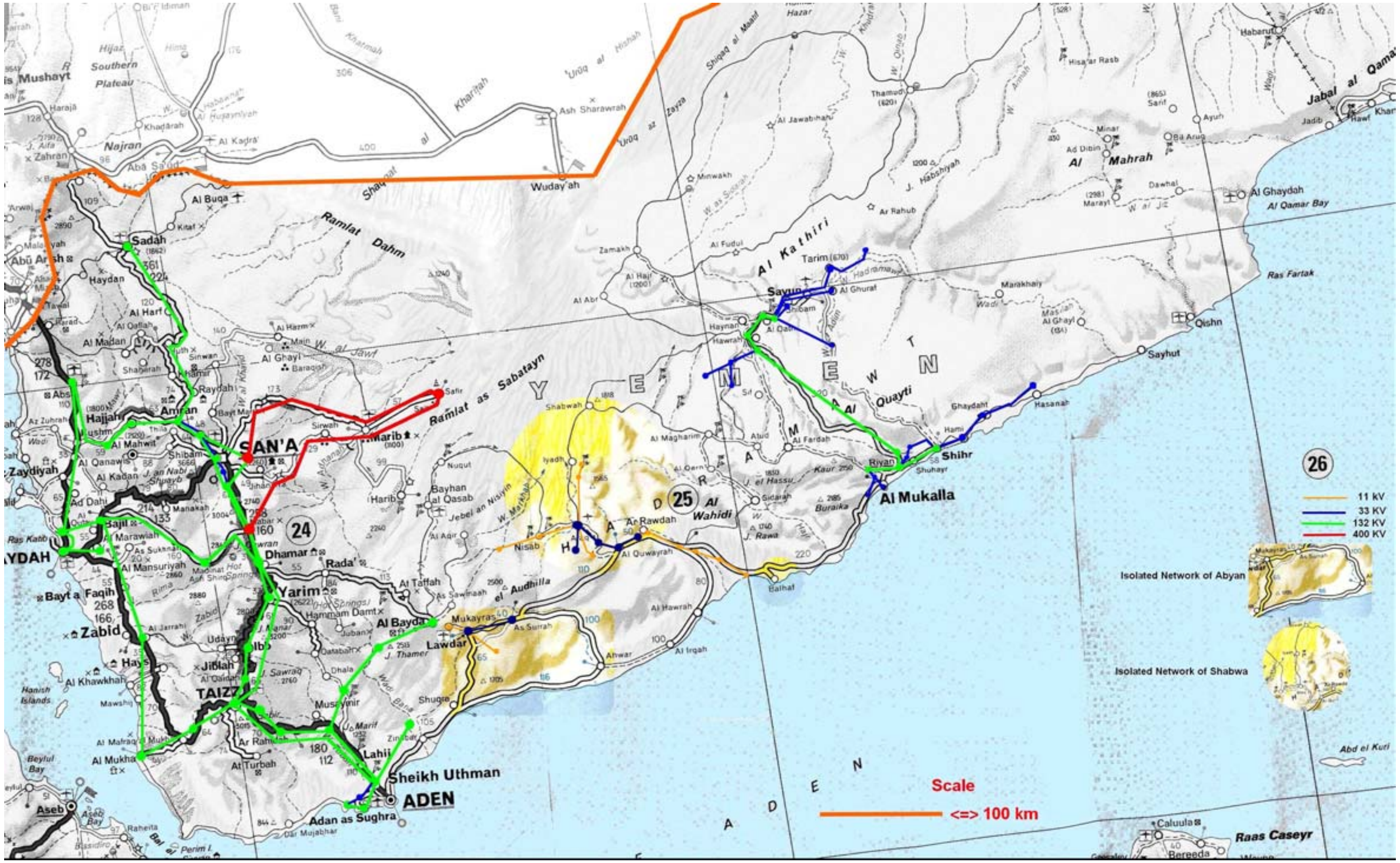
Source: Arab Union of Producers, Transporters and Distributors of Electricity.

There are smaller grids to the east centred around Wadi Hadramaut (Al Bayda), Al Mukhalla (on the coast), Balhaf (the site of the new LNG liquefaction plant) and Ataq. There is also an isolated network around Sada in the north.

A number of studies undertaken in the past have recommended the interconnection of Yemen's isolated grids. The most recent of these, prepared by EdF in 2008 for the Ministry of Electricity and Energy and the Public Electricity Corporation, recommended the connection of three currently isolated grids in the Hadramaut, Al Mukhalla, Balhaf (LNG terminal) and Ataq areas to form an eastern grid and to connect these to the main grid. This scheme is summarised in The EdF study recommended connecting the eastern grid via a 400 kV transmission line from Ma'rib.

Figure 28. The EdF study recommended connecting the eastern grid via a 400 kV transmission line from Ma'rib.

Figure 28 Interconnection of the eastern grid - Yemen



Source: EdF, *Feasibility Study for Balhaf Power Plant and associated Transmission Facilities*, October 2008.

Another study by Fichtner in 2006 recommended the interconnection of the northern grid around Sada city. This connection is also shown in Figure 28 above. The EdF study recommended connecting the eastern grid via a 400 kV transmission line from Ma'rib.

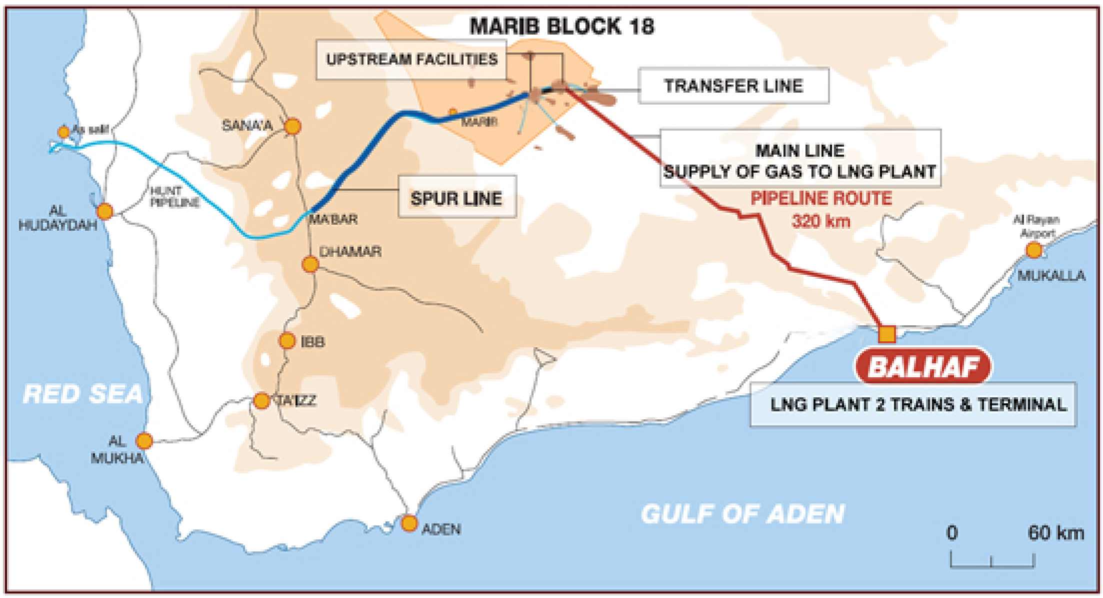
Though nominally included in PEC's investment plans, financing has not been found for these interconnection projects.

A study of the interconnection of Yemen with Saudi Arabia is discussed in Section 11.

9.4.2 Natural gas

The Yemen LNG company (YLNG) has completed a 340 km pipeline from Ma'rib to Balhaf on the coast but the pipeline is currently used exclusively to supply the LNG terminal. This pipeline is shown in Figure 29.

Figure 29 Yemen: Route of the pipeline to supply the LNG terminal

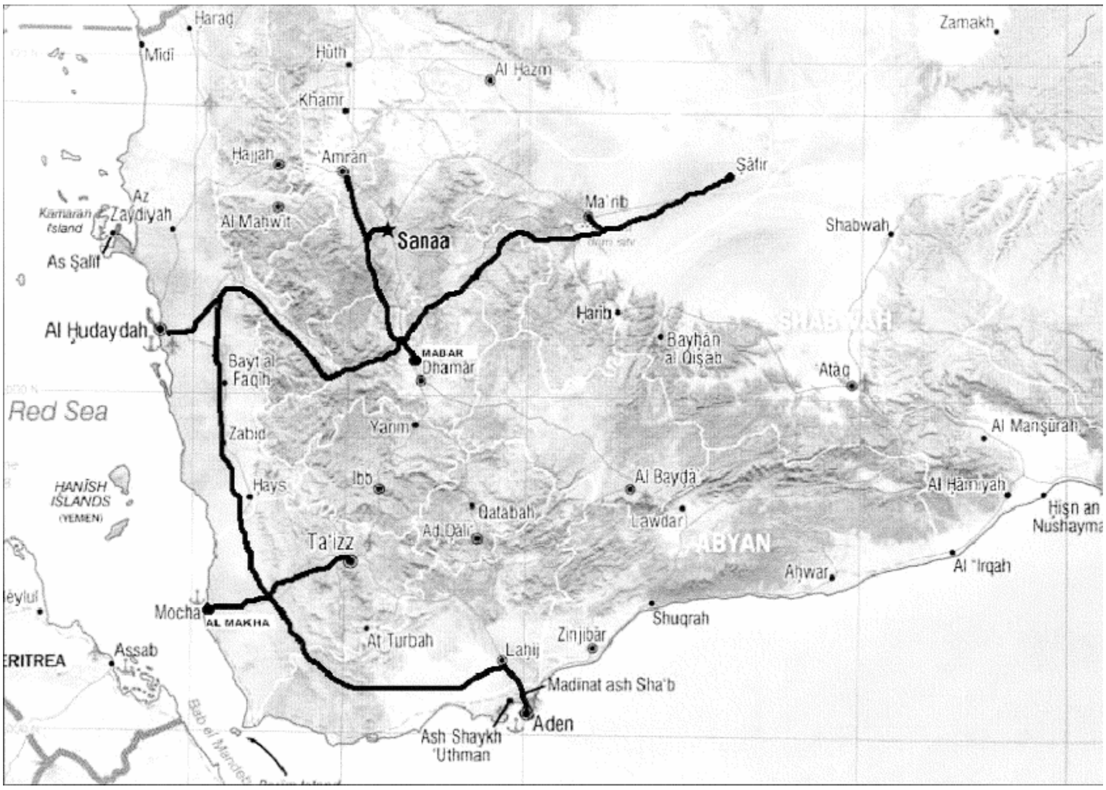


Source: Yemen LNG Company

There is a very short pipeline – less than 10 km - to supply the power plants at Ma'rib when they are commissioned.

There is also a plan to build a pipeline to supply proposed power plants at Ma'bar (south of Sana'a) as well as Al Hodeidah and Aden. The proposed pipeline route is shown in Figure 30. However, there is some concern that sufficient gas may not be available to justify the complete pipeline.

Figure 30 Planned pipeline route



Source: Ramboll, Gas Utilization and Pipeline Feasibility study, 2005

9.5 Supply-demand balance for electricity

The supply-demand balance for electricity is shown in Table 65. The 20% required reserve margin is our own assumption based on an assumed target system reliability of 48 hours LOLE per year. The Table suggests that over 3,000 MW of capacity will be required between now and 2020 after allowing for scheduled retirement of older plants and allowing for the commissioning of the 340 MW Ma'rib I plant in 2009. As described in Section 9.6 below, over 900 MW of capacity is under development or is planned at Ma'rib in addition to Ma'rib I.

Table 65 Electricity supply-demand balance, Yemen

Year	Demand (MW)	Demand + 20% reserve margin (MW)	Installed capacity (MW)	Investment required (MW)
2009	1,485	1,782	1,283	499
2010	1,615	1,938	1,275	663
2011	1,713	2,056	1,300	756
2012	1,819	2,183	1,198	985
2013	1,933	2,320	1,028	1,292

Year	Demand (MW)	Demand + 20% reserve margin (MW)	Installed capacity (MW)	Investment required (MW)
2014	2,039	2,447	1,018	1,429
2015	2,449	2,939	918	2,021
2016	2,567	3,080	918	2,162
2017	2,691	3,229	798	2,431
2018	2,821	3,385	658	2,727
2019	2,958	3,550	658	2,892
2020	3,102	3,722	658	3,064

9.6 Electricity development plans

Yemen's current power sector investment strategy is currently based on a plan prepared by PEC and the World Bank in 2003 and includes the commissioning of gas-fired power plants distributed along a pipeline to be constructed between the gas fields in Ma'rib and Aden, passing by Sana'a and Al Hodeidah and along the coast. The original plan was based on a very low economic value of gas and for this reason the plants chosen were all open-cycle gas turbines. The value of gas has since been recognised to be considerably higher and the most recent plan is to introduce combined-cycle plants instead. A shortage of natural gas may also cause the plan to be substantially modified.

The first gas-fired open-cycle gas turbine plant with a capacity of 340 MW will be commissioned at Ma'rib during 2009.

The latest update on the plan is summarised in Table 66. Some of the plants that are currently committed to be developed as open-cycle plants will be converted to combined cycle as soon as possible – these are indicated with: "OCGT → CCGT".

Table 66 Generation investment plan - Yemen

Plant	Type	Capacity	Year
Ma'rib II	OCGT → CCGT	352 → 528	2013 → 2019
Ma'rib III	OCGT→ CCGT	264 → 396	2014 → 2020
Wind	Wind turbines	180	2012 – 2014

Source: Ministry of Electricity and Energy

9.7 Demand for natural gas

Preliminary projections of demand for gas for the domestic market were presented by the World Bank at a workshop in Sana'a in June 2009 and are shown in Table 67. This excludes demand for gas for export as LNG.

Table 67 Gas demand projections - Yemen

Year	Gas demand (BCM)
2009	0.1
2010	0.9
2011	0.9
2012	0.9
2013	1.5
2014	2.3
2015	3.1
2016	2.8
2017	2.7
2018	2.3
2019	2.2
2020	2.3

Source: World Bank workshop, Sana'a, June 2009

9.8 Review of electricity and gas pricing

9.8.1 Electricity

Electricity tariffs for the Public Electricity Corporation (PEC) are shown in Table 68. The average revenue is approximately YR12 or US¢6/kWh. This is, however, far below the true cost of production – in part because PEC has been forced to purchase electricity from rented diesels in order to meet demand.

Table 68 PEC electricity tariff - Yemen

Group	Block (kWh)	Tariff YR (US¢) /kWh	Fixed charge (YR/month)		
			1 phase	3 phase	CT[48]

[48] Customers requiring a current transformer.

Group	Block (kWh)	Tariff YR (US¢) /kWh	Fixed charge (YR/month)		
			1 phase	3 phase	CT[48]
Urban houses	0 – 200	4 (2)	300	800	3,500
	201 – 350	7 (3.5)	300	800	3,500
	351 – 700	10 (5)	300	800	3,500
	700+	17 (8.5)	300	800	3,500
Rural houses	0 – 100	7 (3.5)	300	800	3,500
	100+	17 (8.5)	300	800	3,500
Commercial		17 (8.5)	400	1,500	3,500
Cement		15 (7.5)	400	1,500	3,500
Water Corporations		15 (7.5)	400	1,500	3,500
Government		18 (9)	400	1,500	3,500

Source: PEC.

9.8.2 Natural gas

Natural gas has not yet been sold in Yemen. The Ministry of Oil and Minerals has proposed to sell gas to PEC at approximately US$3.2/mmbtu but this is still subject to negotiation.

9.9 Legal and regulatory framework

The Ministry of Electricity and Power is responsible for policy making relating to the electricity sector. The state-owned, vertically integrated Public Electricity Corporation (PEC) is the country's main provider of electricity but does not have a legal monopoly over electricity generation.

A new Electricity Law was enacted in 2009 which provides for the establishment of an independent regulator and access to PEC's transmission and distribution networks on a fair and competitive basis by private sector generators and suppliers. According to the new Law, PEC is to be unbundled into generation, transmission and distribution companies. The detailed regulations to be promulgated under the Law are not yet available. There is a three year transition period during which PEC must create generation, transmission and distribution companies in conformity with the new Law.

Detailed regulations will be prepared by a Regulating Board of Electricity Activities to be chaired by the Minister of Electricity and Power; this Board will also regulate tariffs for generation and transmission and wholesale supply and distribution. The tariffs must be approved by the Council of Ministers.

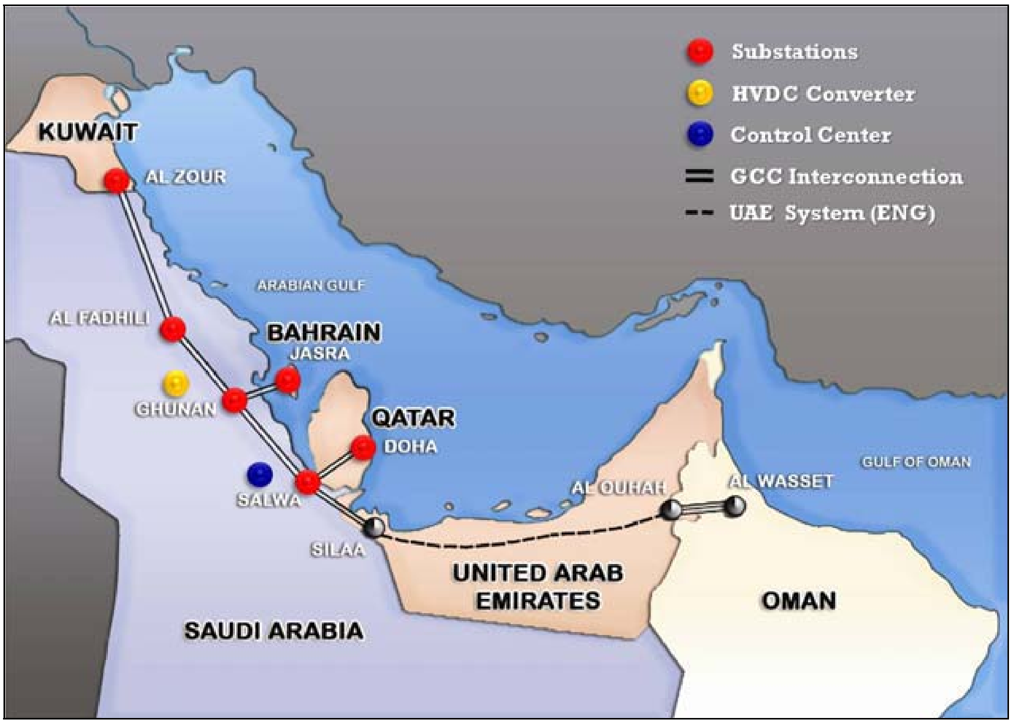
Access to transmission lines will be governed by regulations determined by the Minister in consultation with the Board and will be on a non-discriminatory basis.

10 Opportunities for trade: within the GCC region

The Gulf Cooperation Council (GCC) electricity interconnection scheme was originally conceived in 1981 but took off in earnest in 2001 when the GCC Interconnection Authority (GCCIA) was established and, subsequently in 2004, when the national Governments of the six member states – Kuwait, Saudi Arabia, Bahrain, Qatar, United Arab Emirates (UAE) and Oman – agreed to finance the interconnections and a control centre. The physical infrastructure – see Figure 31 - is being implemented in three phases, the last of which to connect the northern countries (Kuwait, Saudi Arabia, Bahrain and Qatar) with the southern states (UAE and Oman) is expected to be completed in 2010.

The physical infrastructure consists of an AC interconnection of the 50 Hz systems of Kuwait, Bahrain, Qatar, UAE and Oman with a back-to-back converter station to the 60 Hz Saudi Arabian system.

Figure 31 GCC Geographical Route of the Electrical Interconnection



Source: Al Asaad, GCC: The backbone of power reform

In parallel with the interconnection of the GCC electricity networks, the GCC countries have taken steps toward greater integration of the gas networks. The GCC gas pipeline project currently exports from Qatar to UAE and Oman and it is intended that it will export to Bahrain and Kuwait in future though the timetable has been pushed back because Qatar has placed a moratorium on further exports until a feasibility study is concluded – currently scheduled to be completed in 2012. The 600 km pipeline to Kuwait via Bahrain is also complicated because of disputes with Saudi Arabia through whose territorial water the pipeline would need to pass.

The benefits of natural gas pipelines connecting two or more countries are relatively straightforward - generally to allow exports of bulk energy from a country with a surplus of primary energy to a country with a deficit of primary energy sources (it may also improve security of energy supply).

However, in the case of electricity, the benefits of interconnecting power systems are more complex and include:

- sharing of reserve, thereby reducing the capital cost of investment in capacity to meet demand at peak periods or to reduce load shedding,
- trade in electrical energy[49] as an alternative to, or addition to, trading in primary energy such as natural gas or petroleum products,
- fully integrated power sector planning to take advantage of economies of scale in developing power plants for interconnected grids.

These three types of benefits are discussed below. We then discuss the constraints on electricity trade and finally provide conclusions on electricity and gas trade within the GCC countries.

10.1 Benefits of reserve sharing

10.1.1 Types of reserve

On any electrical power system there is a requirement for the provision of sufficient reserve to be in place in order to cover scheduled and unscheduled shut downs of generating capacity or unexpectedly high levels of demand. To cater for the possibility of failing to meet demand for either of these reasons, at the planning stage utilities plan to install generation capacity above the forecast demand (the "planning reserve") and in the operation stage the System Operator schedules enough generation ("standing reserve" and "spinning reserve"). Any lost output associated with an unexpected trip of a generating unit must be provided from the available spinning reserve which is available almost instantaneously and/or from standing reserve that takes time to synchronise with the grid.

The additional generation that is over and above the forecast demand and required by the System Operator within the operational timeframe is called the "operating margin" while the additional generation identified at the planning stage is the "planning margin" or the "installed capacity margin". The installed capacity margin will normally be greater than the operating margin[50].

The required quantity and make up of reserve varies according to:

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[49] Including the potential environmental benefits associated with achieving more efficient power system operation and reducing fuel consumption.

[50] The planning margin should normally exceed the operating margin but if the outturn load growth is higher than expected, the actual operating margin may exceed the original planning margin.

- the power system security criteria of the power utilities involved, and
- the generation mix[51] and demand side options that are available to the System Operator.

10.1.2 How benefits of reserve sharing will be realised

An interconnector between adjacent systems can be used in order to share reserve between the systems and thereby reduce the total overall requirement for reserve. In other words the reserve requirement for the interconnected system is less than the sum of the reserve required if the two systems are operated in isolation. This benefit from interconnection is achieved, even if the load patterns in the two adjacent systems are identical, because there is a low probability of simultaneous outages of plants in the two systems so that if one system suffers an unscheduled outage, generally the other system can provide support.

However, the benefit of reserve sharing increases the greater the diversity of load patterns between two systems. The differences in load pattern may be systematic or non-systematic.

- Systematic differences occur, for example, where peak demand in one system is driven by residential demand in the evening while another system may be driven by air conditioning demand in commercial buildings during the day.
- Non-systematic differences occur where, despite two systems tending to peak at the same general times of the day and the same months of the year, random factors will tend to cause the peaks to occur at slightly different times. For example, temperatures may be broadly correlated between two locations but may differ on specific days for a wide range of small weather-related reasons.

The greater the correlation between the loads in two systems, the lower will be the reserve sharing benefit of interconnection. Nevertheless, benefits still exist because plant outages should not normally be correlated.

10.1.3 Load patterns and reserve sharing

In the case of the GCC countries, the system peak demand - which drives the need for system capacity - is determined by ambient temperature and air conditioning load. The GCC countries tend to have similar weather patterns resulting in peak demands that are highly correlated (in practice they occur simultaneously or at very similar times). The load patterns of the five GCC countries are described in Annex A4 and summarised in Table 69.

[51] Size of units (large units relative to the system peak demand require a larger reserve margin to achieve the same reliability level) and technology (for example, hydro is very good for spinning reserve since its output can quickly be varied to follow variations in load or to step-in when other plants trip).

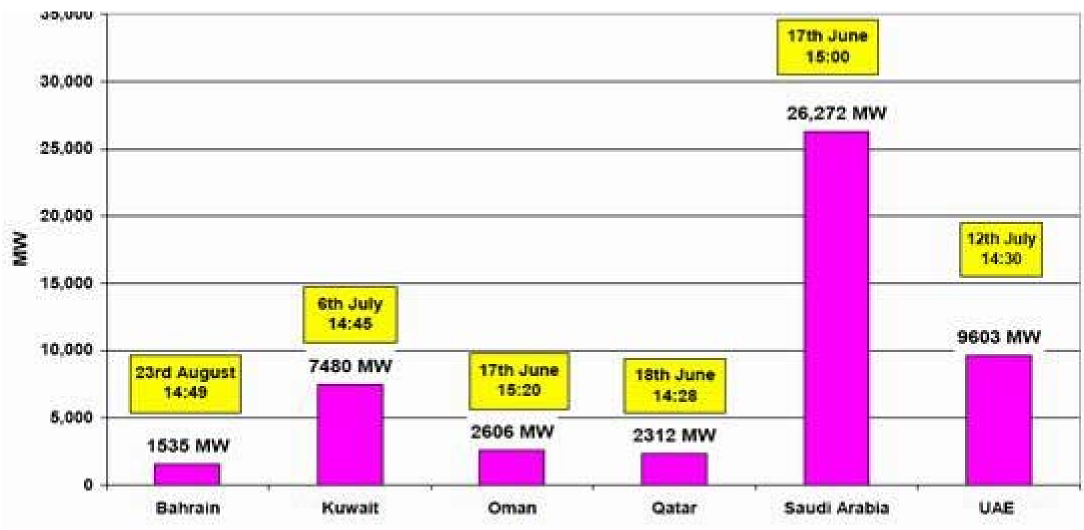
Table 69 Load shape characteristics of the GCC countries

Country	Hour of peak demand	Month of peak demand	Period of lowest demand	Ratio of low demand to peak demand
Kuwait (2003)	14:30 – 15:30	July – August	February	n/a
Saudi Arabia (2006)	15:00	June – Sept.	February	39%
Bahrain (2008)	n/a	July – Sept.	February	n/a
Qatar (general)	13:00 – 15:00	June – Sept.	February	n/a
UAE (2006)	n/a	June – Sept.	January	n/a
Oman	15:00 – 17:00	May – June	February	~50%

n/a = not available

The simultaneity of the peak is again illustrated in Figure 32 showing the peak demand of the GCC countries in 2003. In three of the countries – Saudi Arabia, Qatar and Oman – the peaks all occurred on 17th and 18th of June.

Figure 32 Annual peak load dates and times, GCC countries, 2003



Source: www.gcc-cigre.org

10.1.4 Reserve sharing in practice

The benefits of interconnection were estimated (see below) to include a material reduction in the aggregate need for the total reserves across the GCC region as a result of sharing reserves. However, strict rules are required to govern the manner in which any interconnector is operated in order to ensure that the agreed reserve is available as and when it is required[52]; this will restrict the interconnector's use for other purposes such as trading electrical energy.

We have not had access to the documentation describing the GCC interconnection feasibility study or the draft agreements governing the use of the interconnector, but we have studied various documents that are publicly available and our interpretation below is based on various statements in these publications. Of particular importance to our understanding of the expected role of the interconnection scheme is a paper published in the Electricity Journal, December 2008 - *Engaging in Cross-Border Power Exchange and Trade via the Arab Gulf States Power Grid* – by Hamish Fraser and Hassan K. Al-Asaad. A Power Exchange and Trading Agreement (PETA) is currently under discussion among GCC member states and the expected role of the interconnector will shape this agreement. We understand that the ***basic*** way that the interconnector is intended to operate is as follows:

- Each country will maintain a minimum margin of *installed capacity* over peak demand. The margin required under this agreement is lower than the margin that would otherwise have been required without interconnection (to achieve the same level of reliability). Because there is some diversity of load patterns between countries and because of the low probability of simultaneous plant outages in two countries, target reserve margins can be lower (see Table 70 below) and this reduces total installed capacity requirements and lowers the total capital costs.

- In operation, each country will schedule operating reserve (spinning reserve and standing reserve) ready to meet unexpected outages as if they are isolated from the interconnector. In the basic operating mode for the interconnector, it appears that the countries are not normally expected to rely on the interconnector for spinning reserve or standing reserve. This implies that in normal operation, the interconnector would not be loaded nor would it be relied on to provide spinning reserve (though inevitably the system may draw power through the interconnector if one of its plants trip).

- However, even if the countries adhere strictly to the agreed margin of installed capacity over demand, and adhere strictly to policies governing operating reserve, they would inevitably occasionally find themselves with insufficient capacity of their own to meet their demand (usually, but not always, at peak times) and the interconnector would then be used to provide support. This support would be provided instantaneously from neighbouring countries' spinning reserve if the outage is large and unforeseen and its own spinning reserve is insufficient. Support could be provided from neighbouring countries' standing reserve a short time after an unexpected outage if its own capacity is not sufficient to meet the shortfall. The support could be planned (scheduled a few hours or even days ahead) if several of its plants are unexpectedly unavailable and repair will take several days

[52] Failure to do so can result in severe system disturbances or total system collapse.

and it has no other plants available (despite the adhereance to the installed capacity margin requirements). Spinning reserve support by other GCC countries in the event of a major outage will be automatic but the exact agreements describing which country brings plants into operation specifically to provide other reserve support for their neighbours has not been described publicly.

- In addition to this occasional forced use of the interconnector, GCC states may additionally use the interconnector to satisfy their own installed capacity obligations by contracting with neighbours to provide some of the required capacity. This appears to be the second most important role envisaged for the interconnector. GCC members may nominate capacity in other GCC countries and, in combination with "installed capacity interconnector rights", partially satisfy their installed capacity obligation using the interconnector.

- Next, in terms of priority for the use of the interconnector, PETA will also allow for the possibility that countries will use the interconnector to satisfy normal operating reserve requirements (spinning reserve and standing reserve), but does not see this as being a major role for the interconnector. In other words, as described above, the countries are generally expected to provide sufficient spinning reserve and standing reserve themselves and only rely on the interconnector in emergencies when they have insufficient capacity to meet demand or insufficient capacity to operate their system stably.

- Finally, in terms of priority, the interconnector may be used for trading energy in the form of electricity.

10.1.5 Estimates of reserve sharing benefits

The feasibility study undertaken in 2003 estimated the benefits of GCC interconnection in terms of reduced installed generating capacity and based on the primary role of the interconnector described above. These benefits, up to 2028, are outlined in Table 70.

Table 70 Benefits of GCC interconnection

	Demand	Installed cap (MW)		Reserve (MW)		Saving		
	(MW)	isol-ated	conn-ected	isol-ated	conn-ected	(MW)	(%)[53]	US$ mn[54].
Phase 1								
Kuwait	27,017	30,397	29,066	3,380	2,049	1,331	4.9%	932

[53] Percentage of maximum demand.

[54] Very approximately, assuming open-cycle gas turbines.

	Demand	Installed cap (MW)		Reserve (MW)		Saving		
	(MW)	isol-ated	conn-ected	isol-ated	conn-ected	(MW)	(%)[53]	US$ mn[54].
Saudi Arabia	23,210	26,361	24,752	3,151	1,542	1,609	6.9%	1,126
Bahrain	4,989	5,782	5,494	793	505	288	5.8%	202
Qatar	4,649	5,427	5,060	778	411	367	7.9%	257
Total	59,865	67,967	64,372	8,102	4,507	3,595	6.0%	2,517
Phase 2								
UAE	29,358	32,651	31,424	3,293	2,066	1,227	4.2%	859
Oman	4,558	5,221	4,930	663	372	291	6.4%	204
Total	33,916	37,872	36,354	3,956	2,438	1,518	4.5%	1,063
Grand total	93,781	105,839	100,726	12,058	6,945	5,113	5.5%	3,579

Source: correspondence with SNC-Lavalin International.

We note that the margins shown in Table 70 above are low relative to international standards – both for the systems in isolation and for the interconnected system. The margin should vary with the size of the system so that a very large system such as the interconnected system of the Former Soviet Union or of the USA could have low margins because probabilistically, to achieve a given reliability, the reserve requirements are lower. Similarly, the economic loss from outages in developing countries tends to be lower than the economic loss from outages in developed countries, so developing countries can tolerate lower margins. But neither of these circumstances is true in the GCC countries[55] and the margins shown in Table 70 appear low. Nevertheless, for the purposes of assessing the benefits of interconnection, it is the comparison between the reserve margin with and without the interconnection that is important and the relative impact of the interconnector on this reserve margins appears reasonable.

The estimated capital cost of phase 1 of the GCC interconnection[56] was US$1,095 million and the GCC interconnection studies showed a benefit to cost ration of 1.77 which implies an economic benefit of $1,938 million. While we have not seen any figures for the economic benefit associated with phase 3[57], we have estimated this to be approximately US$820 million which results in a total benefit for phase 1 and 3 combined of around $2,760 million. These economic benefits exclude the potential savings associated with any other power trading undertaken for purposes other than the provision of reserve.

[55] Even though Saudi Arabia has a relatively large system demand, it is not large by international standards and, moreover, it is not one integrated network.

[56] Phase 1 comprises the interconnection of Kuwait, Saudi Arabia, Bahrain and Qatar systems.

[57] Phase 2 is the internal interconnection of the UAE and Oman systems while Phase 3 involves the connection of UAE to Saudi Arabia thereby interconnecting all the GCC States.

10.2 Benefits of energy trade

There is clear economic logic for Qatar to export natural gas via pipeline to its neighbours. There is no strong economic logic for trade in bulk energy in the region via electricity transmission lines.

Energy can be traded in its raw state as oil or coal or natural gas, or in processed form as heavy fuel oil or distillate or LNG. It can also be traded as electricity. In Section 10.2 we consider the benefits of trading energy between the GCC countries and, in particular, the benefits of trading energy in the form of piped natural gas or in the form of electricity.

10.2.1 Economic value of energy resources in GCC countries

The GCC countries are, with one exception, rich in oil and gas resources. The countries are home to the world's largest concentration of hydrocarbon resources in the form of crude oil and natural gas. The GCC countries have 45% of the World's proven oil reserves and 25% of the World's gas reserves. Kuwait holds the fourth largest reserves and is just outside the top 20 holders of gas reserves globally. Saudi Arabia has the world's largest oil reserves and is the world's largest producer of oil. The UAE is an important oil producer with the fifth largest proven oil reserves in the world and is the world's eighth largest producer. Qatar and Oman are also major world producers of oil and natural gas and Qatar has the third largest gas reserves in the world. Among the GCC countries, only Bahrain is endowed with relatively small reserves of gas and oil by the standards of its neighbours.

The GCC countries are all members of OPEC and the production of oil is controlled by agreement among OPEC members in order to optimise revenues from oil. This constraint has important implications for the economic value of oil that is used to meet domestic energy needs. In countries that are small in relation to the international market[58], the economic value of oil consumed domestically is the foregone export earnings. In the case of OPEC countries, domestic oil consumption will (or should if the exports are capped according to the agreements) only affect export revenues in the long term when resources are being depleted. Effectively, by saving consumption today they are not losing export revenues but, instead, the countries are banking the oil for the distant future. Given reasonable discount rates and a relatively long period until the oil becomes depleted, the value of oil consumed domestically in power generation in such countries can be low. This could be true in some of the GCC countries such as Saudi Arabia, Kuwait and UAE depending on whether production is constrained in the long-term by choice or whether it is constrained for techno-economic reasons. Where oil exports are capped by OPEC quotas (rather than by long-term production constraints) then in these countries it is less economically attractive to develop natural gas resources to substitute for oil in power generation.

[58] In economic terminology, the countries are 'price takers'.

Paradoxically, the economic benefit of exporting natural gas to countries outside the region is also affected by the GCC countries domination of the international oil market. Since gas competes with oil internationally, exporting gas will also reduce the demand for oil and will therefore reduce the market price for oil. This weakens the economic attractiveness of exporting natural gas by OPEC members – particularly Saudi Arabia.

Within the region there are benefits to trading natural gas (and oil) among fellow OPEC members since this should not, in theory, depress the international price of oil. There are therefore clear opportunities for exporting natural gas from the gas-rich countries (particularly Qatar and Saudi Arabia) to those countries that are relatively less well endowed with gas or oil resources (Kuwait, Bahrain, UAE and Oman). Natural gas exports could be in the form of piped natural gas or could potentially be in the form of electricity generated using natural gas.

10.2.2 Shortages of natural gas

Despite the abundance of energy resources in the UAE and Oman, two of the Emirates (Dubai and Abu Dhabi) and Oman have begun the development of, or are considering developing, power plants using imported coal. This is driven in part by concerns that Qatar has over-committed to LNG exports leading the Qatar government to place a moratorium on further commitments of natural gas exports (including commitments to Bahrain, UAE, Oman and Kuwait) until gas resources from its north field are guaranteed.

Dubai is also planning to build an LNG import terminal to be supplied with LNG by Shell either from Qatar or from outside the region.

Similarly, Kuwait expects its first LNG import terminal to begin commercial operations in August 2009. Imports of 1.6 million tonnes of LNG (equivalent to 2 BCM of natural gas) are expected to come 600 km through the Persian Gulf from Qatar under a five year agreement signed with Qatar's Ras Gas.

Shortages of natural gas in the region and under-development of gas resources has also resulted from national pricing policies for natural gas that encourage the utilisation of gas, particularly for use in energy intensive industries such as petrochemicals and fertiliser, but do not encourage the exploration and development of gas reserves. According to Justin Dargin of Harvard University[59], development costs for gas resources in the GCC countries are around US$4/mmbtu while domestic pricing policies hold feedstock prices for natural gas at between US$0.35/mmbtu in Iran to a high of US$1.19/mmbtu in Egypt. Saudi Arabia, which has some substantial potential for development of its gas resources, offers prices of only US$0.75/mmbtu.

Under-development of gas resources in the region is also, in part, because gas resources are often associated with oil, and production of gas is constrained by OPEC oil production agreements.

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[59] *Prospects for Energy Integration in the GCC: An Analysis of the GCC Energy Sector*; Research Seminar- Dubai School of Government, March 3, 2009; Justin Dargin, Dubai Initiative-Harvard University.

An additional factor affecting investment in exploiting gas resources among GCC countries, either for export of for domestic use, is the uncertainty over the availability and reliability of gas from Iran and Iraq, both of which have very large potential gas resources that could be exploited for export when political circumstances allow a dependable supply. Negotiations over terms for the import of gas have also been problematic. A number of projects have been proposed but none have made significant progress:

- A gas export contract between **Iran** and Crescent Petroleum based in Sharjah, **UAE**, involving a sub-sea pipeline and delivery of 6 BCM per year over a 25 year period, was originally signed in 2001, but agreement has recently stalled.

- **Kuwait** also considered importing natural gas from **Iran**. In early 2005, Kuwait signed a preliminary agreement to import 2.9 BCM per year of natural gas from Iran over a 25-year period commencing in late 2007. This would have involved a 260-km pipeline to transport the gas from Iran's South Pars field into Kuwait. The deal was held up by the need to resolve maritime border issues in the region, specifically on the Dorra offshore natural gas field.

- Prior to the 1990/1991 Gulf War, **Kuwait** received significant volumes of natural gas from **Iraq**. The gas came from Iraq's southern Rumaila field through a 40", 160 km pipeline to Kuwait's central manifold at Ahmadi. Kuwait and Iraq discussed plans to restart the pipeline and a memorandum of understanding between the two governments was concluded in December 2004. The first phase of the project was to have been a modest 0.4 BCM per year to be transported through the existing pipeline. The second phase could involve refurbishment of the pipeline and associated pumping stations to allow the volume to increase to 2 BCM per year. These plan have not yet led to the resumption of gas imports to Kuwait from Iraq.

10.2.3 Trading energy as natural gas or as electricity

There are very obvious economic benefits to the GCC countries in developing gas reserves and trading gas between GCC countries either by pipeline or as electricity. The obvious importing countries are Bahrain, UAE, Oman and Kuwait and the exporting countries are Qatar and, possibly, Saudi Arabia[60].

As a general rule, when faced with a choice between transporting large quantities of energy in the form of electricity or in its raw form as piped natural gas, it is cheaper to transport energy as piped natural gas. This would suggest that the strengthening

[60] There is little economic logic for Qatar to export gas in the form of LNG to the international market and lose a significant part of the value of the gas through the cost of liequefaction, shipping and re-gasification when it could export that gas much more cheaply by pipeline to its regional neighbours. Since the neighbouring countries are contemplating building capital intensive coal-fired plants that use imported coal, then those GCC countries should be willing to pay reasonable prices for piped gas from Qatar.

the gas pipeline network and increased trade in natural gas should be the region's priority ahead of strengthening the electricity interconnections to allow trade in electrical energy.

We note too that there are major shortages of potable water in the region and many power plants in the region are dual purpose and use waste heat from the power plants to produce desalinated water. While electricity can be produced close to fuel sources and transported to the load centres, this is not economically feasible for desalintated water. This tends to favour developing power plants close to population centres where there is a demand for both water and electricity, and transporting natural gas (or other fuels) to these power plants.

There appear to strong benefits in exporting natural gas by pipeline from Qatar to Bahrain, UAE, Oman and Kuwait. Opportunities may also exist for further developing Saudi Arabia's gas resources both to substitute for oil-based power generation within the country (though the opportunity cost of oil is low) or for export of natural gas via pipelines to its neighbours such as Kuwait, UAE or Oman.

10.3 Benefits of electricity trade in general

There will be economic benefits to electricity trade in the GCC region, other than trade in firm bulk energy.

Given that large-scale trading of energy within the GCC will be carried out most effectively using natural gas pipelines – as described above – the opportunities for trading energy as electricity will arise on a more modest scale including:

- temporary power capacity shortages and surpluses in some of the countries arising accidentally because outturn demand is below or above the levels previously forecast – these capacity surpluses can be exploited to trade electrical energy provided that the fuel, or the capacity to produce the fuel, is also available to supply the power plants,

- differences in system load patterns at certain times of the day or year allowing the regular export or import of cheaper energy from one country to another.

Opportunities may exist to take advantage of temporary capacity surpluses in some of the countries. Such surpluses may occur either because of the lumpiness of investments – particularly for small systems – or because the outturn demand growth is less than expected. Surpluses of this type are only useful if they are accompanied by deficits in other countries and provided that there is sufficient fuel to supply the power plants with surplus capacity. Such surpluses may arise in the GCC countries in the future but currently most of the GCC countries and Yemen are struggling to commission power plants fast enough to keep pace with growing demand and there are no countries with surplus capacity in the region. Since the economies of GCC countries tend to be affected directly or indirectly by the same international influences (primarily international oil prices), unexpected surpluses or deficits will generally affect all of the GCC countries simultaneously[61]. There will therefore be fewer opportunities of this type in the GCC trading block than in other trading blocks which have more diversified economies. Opportunistic trade of this type is useful to avoid load shedding or reduce the cost of fast-track investments, but cannot necessarily be relied upon to provide secure electricity supplies.

As described in Annex A4, load shapes among the regions' countries are rather similar. Peak demand is driven primarily by air conditioning loads from offices, shops and residential buildings during the hot summer months. The peak periods normally occur within the working day during the early afternoon and again in the early evening. There is some variation among the GCC countries, with some systems peaking in the early evening and others peaking in the early afternoon, but generally the variation is not significant. There is also some considerably uniformity in the timing of high temperatures in the region so that the peak can occur on the same day in several countries. In 2003, for example, the system peak occurred within 24 hours of each other in Saudi Arabia, Qatar and Oman[62].

Despite the similarity in load patterns, opportunities could exist to trade electrical energy during low demand periods of the year or periods of the day where there are substantial differences in the short-run marginal cost of generating electricity. This might occur if, for example, one system would otherwise generate electricity using expensive fuel (eg., distillate) while another has spare capacity that could use cheaper indigenous fuels (oil or natural gas). Generally, however, the opportunities for such trades in the GCC countries are complex and may be very limited:

- Although gas imported to Bahrain, UAE or Oman from Qatar may be relatively expensive per mmbtu when compared with the economic value of indigenous petroleum products used in oil-fired plants in, say Saudi Arabia or Kuwait, because of take-or-pay or ship-or-pay arrangements for gas and the high sunk costs of investments in pipelines and gas gathering systems, the avoided costs may be low and there may be few savings in importing off-peak electricity.

- The demand for water does not decline to the same extent in winter months as the decline in the demand for electricity[63]. Power production will continue to be needed in order to produce water and the opportunities for importing cheap electricity will therefore be constrained.

[61] The relative impact may differ between countries, but it will tend to lead to all countries simultaneously being in deficit or surplus. Surpluses or deficits are only exploitable if they are matched by corresponding deficits or surpluses in other countries.

[62] On the 17th or 18th June between 14:00 and 15:00. Source: *Prospects for electricity trade between the GCC countries*, Mr. Keith Miller, ADWEC, Power Transmission and Distribution Forum, March 2005.

[63] See: *Prospects for electricity trade between the GCC countries*, Mr. Keith Miller, ADWEC, Power Transmission and Distribution Forum, March 2005.

- The power generation technologies used in the region and the fuels used tend to be similar, thus reducing differences in short-run marginal costs of generation between different systems[64].

Opportunities for exploiting surplus off-peak electricity generation could arise from the use of open-cycle gas turbines in some of the countries of the region. Open-cycle plants are more often used in Saudi Arabia and Kuwait because of the low economic cost of petroleum products. In theory there are opportunities for increased production from combined-cycle plants in other countries to displace generation by open-cycle gas turbines in Saudi Arabia and Kuwait. But open-cycle gas turbines have been chosen precisely because the value of fuel is very low. Additionally, the interconnections of the Saudi operating areas is likely to lead to increased commissioning of combined-cycle plants within Saudi Arabia and reduced use of open-cycle plants, thus reducing the opportunities for trading between GCC countries.

10.4 Constraints on electricity trade

The GCC interconnector allows non-firm[65] trade but priority is given to reserve sharing and, given the limited size of the interconnector, will not allow much firm capacity or energy to be traded.

The import capacities for each of the GCC countries are as detailed in Table 71[66]. These limits were determined by technical modelling[67]of a number of scenarios.

Table 71 GCC interconnector import capacity

Power system	Import capacity (MW)
Kuwait	1,200
Saudi Arabia	1,200
Bahrain	600
Qatar	750
UAE	900

[64] Unless coal-fired power plants are constructed.

[65] Non-firm capacity or energy means that if contingencies arise requiring the use of the interconnector then supply cannot be assured and no compensation will be given.

[66] See *Progress Report on the Gulf Council Electricity Grid System Interconnection in the Middle East*, Adman Al-Mohaisen and Luc Chausse.

[67] See footnote 66 – including loadflow, stability and short circuit analysis.

Power system	Import capacity (MW)
Oman[68]	400

The above capacities define the maximum power that any given power system can import in the event of a contingency (such as the loss of a generating unit) on their system assuming that the pre-contingency import was zero[69]. For example, Oman can import up to 400 MW in the event of a generator trip on its system so long as there is no simultaneous contingency on another GCC power system. It is noted that the values in Table 71 are for the situation where all interconnector circuits are in service and these import limits will be reduced in the event of any extended outage on the interconnector circuits.

The ability to trade capacity and energy over the GCC interconnectors is thus limited by two key factors:

- The interconnector import capabilities themselves are limited to between 400 MW and 1,200 MW depending upon the power system concerned; and
- Priority of interconnector use is given to the sharing of reserve rather than to trading other electricity services.

10.5 Specific opportunities for electricity trade

It is unclear whether it would be worth reinforcing the interconnector between the northern and southern group to allow increased non-firm electricity trade; it is unlikely that Bahrain or Qatar would wish to use the interconnector to provide operating reserve.

As described in Section 10.1.4, it is expected that some interconnector transfer capability will be available to meet the installed capacity obligation, ancillary service obligations (primarily operating reserve), and also the trading of energy - in that order of priority. We understand that the GCC Interconnection Authority has yet to determine how much transfer capability will be allocated to member states for such trading.

Below we consider two specific examples of trade in addition to the basic role of the interconnector to provide emergency support, and we consider whether reinforcement of the interconnector might be worthwhile:

[68] According to the Oman Power and Water Procurement Co., 7-Year Statement 2009-2015, the interconnector capacity is 600 MW, of which 170 MW will be firm in 2009-10 and 300 MW will be firm thereafter.

[69] In other words no power flow between the two systems prior to a contingency. In the event of a loss of generation, power will automatically flow across the interconnector and will make up part of the shortfall on the system where the loss took place.

- non-firm energy trade between the northern group (Kuwait, Saudi Arabia, Bahrain and Qatar) and the southern group (UAE and Oman), and
- use of the interconnector by Bahrain or Qatar to provide operating reserve.

Similar assessments could be undertaken for trade between other GCC countries.

10.5.1 Northern-Southern interconnector

We consider here an example of the use of the interconnector for trading non-firm energy between two countries (and, in this case, transiting through a third).

The Northern-Southern interconnector, to be completed in 2010-11, will link the northern networks of Kuwait, Saudi Arabia, Bahrain and Qatar with the two southern networks of UAE and Oman.

It should be noted that the main backbone of the GCC interconnector runs through Saudi Arabia but operates at 50 Hz and is not part of the Saudi Arabia's system (which is mostly 60 Hz and connects to the interconnector via a back-to-back converter substation). The UAE's system is the only part of the GCC interconnector that might be used to wheel power through one system into another – in this case it could be used for wheeling power to Oman.

The connections between the GCC and UAE and between UAE and Oman are as follows:

- The transmission connection into UAE (Salwa in Saudi Arabia to Shuweihat in UAE) involves a double circuit 400 kV line with a length of 100 km. The UAE import limit from the interconnector is currently 900 MW.
- The proposed UAE to Oman (Al Oha to Al Wassit) interconnector involves three 220 kV circuits with a length of 52 km. The Oman import limit is currently 400 MW.

Given UAE's own energy deficits, UAE is unlikely to be a direct exporter of electrical energy to Oman, and imports from other GCC states would therefore require power to be wheeled through UAE; this would reduce the interconnector capacity available to UAE. If, for example, Oman wished to contract with Qatar to provide 400 MW of capacity to help meet its installed capacity obligation, then this would reduce the interconnector capacity available to UAE and would therefore have to be agreed with UAE.

Given the difficulties that GCC countries have faced in commissioning power plants fast enough to meet their own demand growth, it seems unlikely that UAE or Oman would be able to persuade their neighours to build capacity to meet UAE or Oman's "installed capacity obligation" as defined by PETA. This leaves the interconnector available for ancillary services (operating reserve) and energy trade. The possibility of using the interconnector for operating reserve is discussed below in relation to

Qatar and Bahrain and here we assume that the north-south interconnector is not used for this purpose and instead consider the possibility of using the interconnector for energy trade (plus emergency support).

As discussed in Section 10.2, the GCC states will probably not develop power plants specifically in order to export energy in bulk[70] to other member states (eg., from Qatar to Oman), but opportunities may exist to exploit differences in operating costs of power plants in order to trade energy at certain times of the day.

Oman's MIS system, for example, has a number of relatively inefficient open-cycle gas turbine plants which would probably be used in mid-merit and peaking roles while using its CCGT and combined power and desalination plants for base-load roles. Oman also imports natural gas from Qatar. While the open-cycle plants may not directly use imported natural gas, there might theoretical be economic opportunities, at certain periods of the year and shoulder periods of the day, to import electricity from Saudi Arabia, back-off production from the open-cycle plants and use Omani gas to displace imported gas. We are using Saudi Arabia as an example but the same discussion could apply to other GCC countries. The feasibility of this strategy depends on a range of complex factors:

- the flexibility of the Oman-Qatar gas import contracts in absolute terms and within the year or between years (whether take-or-pay and ship-or-pay agreements mean that there are few cost savings from reduced gas consumption or from shifting gas demand from one period to another),
- the price of gas imported to Oman compared with the opportunity cost of fuel that Saudi Arabia assumes when calculating the price of electricity exported to Oman (does it calculate the value of gas or crude oil at international market values or as the opportunity cost),
- the flexibility of the gas transmission network within Oman to divert imported and domestic gas between power plants,
- the flexibility of gas supply contracts between the power plants in Oman (do the power plants contracted to OPWP have individual gas supply contracts?),
- the willingness of UAE to agree to allow Oman to use a portion of the UAE-Saudi Arabia interconnector for non-firm import of electrical energy,
- the willingness of Saudi Arabia to enter into non-firm export arrangements with Oman,
- load patterns in the two countries, and
- the merit order of Omani plants and the variable fuel and operating costs of Omani plants at times when Saudia Arabia has surplus capacity.

[70] It would be cheaper to export the natural gas by pipeline.

The maximum import capacity to Oman through the interconnector is assessed by GCCIA to be 400 MW but the non-firm capacity is assessed by the Oman Power and Water Procurement Company to be 600 MW. This would set the upper limit on the amount of power that could be imported with the current infrastructure. This is considerably less than the capacity of Oman's open-cycle power plants (over 1,500 MW).

The capacity of the interconnector between UAE and Oman could be increased by adding an additional circuit. However, a full range of technical studies would be required in order to establish the extent to which the import limit could be increased through the addition of an additional circuit without jeopardising system security. Given the modest distance involved, it might be worth undertaking cost-benefit analysis to establish whether such an interconnector upgrade could be justified for energy trading.

The reinforcement of the interconnector between Saudi Arabia and UAE would additionally be necessary to allow additional transit of 400 MW to 600 MW of electrical energy through UAE to Oman and may be necessary before UAE would agree to allow any imports of electrical energy. The interconnection into UAE (Salwa in Saudi Arabia to Shuweihat in UAE) involves a double circuit 400 kV line with a length of 100 km. The UAE import limit from Saudi Arabia is currently 900 MW. Adding a second double circuit line could be expected to increase the import limit significantly but technical studies would be required in order to ensure that this was indeed the case and, again, economic studies would be required to consider whether energy trade is justified.

Whether consideration of the reinforcement of these two interconnectors is worthwhile to allow increased trading of electrical energy will depend on whether the interconnector currently planned is found to be used to its maximum potential. It would probably be premature to consider strengthening the capacity of these interconnectors at the current time.

10.5.2 Connections with Bahrain and Qatar

Here we consider an example of the use of the interconnector for providing operating reserve to two systems that are supplied by two clear spurs from the backbone interconnector (running through Saudi Arabia) – Bahrain and Qatar. We also consider whether the strengthening of the interconnectors with Bahrain or Qatar might be justified solely for the additional benefits of providing operating reserve.

As described above (Section 10.1), operating reserve covers spinning reserve and standing reserve. Spinning reserve refers to capacity that can be brought into operation within seconds or minutes – usually provided by plant that is part loaded – while standing reserve refers to plant that takes longer to be synchronised[71]. Such reserve is usually required to cover unexpected trips of power plants but can also be

[71] This may be referred to as primary, secondary and tertiary reserve. The definitions (timeframe for making this reserve available to the system) vary from country but a detailed discussion is unnecessary for the purposes of this paper.

required to cover other contingency events such as the loss of an interconnector. Operating reserve requirements are often specified in terms of the single largest contingency event, typically the loss of the largest 'unit' on the system or, for a system that imports electricity or has power plants concentrated in one location and connected to the main grid by a transmission line, the loss of a transmission circuit.

We note that Bahrain and Qatar have some relatively large plants in comparison to the size of the system (and the interconnector). The Ras Laffan 'C' CCGT plant in Qatar will, when completed, have an overall capacity of over 2,700 MW and will be the largest in the country. Operating margins are, however, typically measured in terms of the largest contingency event. Though the total capacity of the Ras Laffan 'C' plant may be very large, the single contingency events are more modest. The Ras Laffan C plant uses eight gas turbines with a capacity of approximately 200 MW each combined with four steam turbines of 260 MW to produce combined-cycle blocks of approximately 680 MW. The largest contingency event would then be a 200 MW gas turbine and half of the output of a steam turbine, totalling 330 MW. The interconnector, which has a capacity of 750 MW, would provide sufficient capacity to fill the immediate deficit arising from this contingency.

Similarly, the 600 MW capacity of the interconnector with Bahrain is sufficient to fill the deficit left by contingencies from loss of units from its combined-cycle blocks.

Bahrain and Qatar could potentially rely on the interconnector to provide all of their operating reserve. To do so, they would need to reach agreement:

- with GCCIA to allocate interconnector capacity for this purpose, and
- with a neighbouring state to provide that reserve.

If the interconnector capacities are not allocated to meet the installed capacity obligations (nor allocated for trade in electrical energy) then there should be no constraint to allocating the interconnector capacity to provide operating reserve.

However, given that operating reserve in the GCC countries will be provided primarily by open-cycle gas turbine plants, it is questionable whether neighbouring countries could provide operating reserve more cheaply than Bahrain and Qatar.

Additionally, even if the interconnector is used to provide operating reserve from neighbouring GCC countries, system operators in Bahrain and Qatar would probably wish to maintain at least some of their own operating reserve so that the interconnector capacity to these two countries is unlikely to be fully allocated to provide operating reserve.

10.6 Opportunities originating in Saudi Arabia

Opportunities may exist for further developing Saudi Arabia's gas resources in the Empty Quarter in the south-east of the country for export to UAE and Oman.

Oil production at the Shaybah field in the Empty Quarter area bordering UAE and Oman (see Figure 33) began production in 1998, and in April 2004 reached around 560,000 bbl per day. The Shaybah field is connected to Abqaiq, Saudi Arabia's closest gathering centre via a 630 km oil pipeline. The field has a large natural gas cap with estimated reserves of 700 BCM. Gas production of 25 MCM per day is currently reinjected but could be exploited to produce 9 BCM per year.

The field is about 10 km south of the border with Abu Dhabi and perhaps 200 km from the Dolphin pipeline at Al Ain or the pipeline at Maqta (see Figure 4 in Section 2.2) and is therefore closer to Abu Dhabi than to Saudi Arabia's own load centres.

The South Rub al-Khali Company (SRAK), a consortium of Saudi Aramco and Royal Dutch/Shell, is exploring the Shaybah and Kidan oil fields, aiming to produce 14 MCM/day of gas (or 5 BCM per year).

Russia's Lukoil is also exploring for non-associated natural gas in the Saudi Empty Quarter, near Ghawar, as part of an 80/20 joint venture with Saudi Aramco, known as Luksar. This development is closer to Saudi Arabia's main load centres and the gas, if developed, would be used for the domestic power sector.

Figure 33 Natural gas resources – Saudi Arabia

10.7 Conclusions on electricity and gas trade

10.7.1 Assessment

The discussion in the previous sub-sections suggests the following:

- There appear to be strong benefits in increased export of natural gas by pipeline from Qatar to UAE and Oman and in developing natural gas exports from Qatar to Kuwait and Bahrain. Qatar is a major exporter of natural gas as LNG to the rest of the world, with high costs of liquefaction, transportation and re-gasification, while its close neighbours are resorting to importing bulk energy from outside the region, also facing relatively high transportation costs. There are clear savings available to Qatar and its neighbours from regional trade via pipelines that have much lower overall transport costs.

Kuwait, Bahrain, UAE and Oman are all waiting for Qatar to relax its moratorium on further gas export agreements. However, even when the moratororium is lifted, the development of a 600 km gas pipeline linking Qatar with Kuwait, via Bahrain, is subject to some uncertainty until agreement is reached with Saudi Arabia over the use of its territorial waters in the Persian Gulf.

- Opportunities may also exist for further developing Saudi Arabia's gas resources both to substitute for oil-based power generation within the country or for export of natural gas via pipelines to its neighbours such as Kuwait, UAE or Oman. Opportunities may exist in this regard for gas developments in the Empty Quarter in the south-east of the country.

- There are constraints to the development of natural gas resources in the short-term (particularly Qatar) and until these are resolved, some GCC countries are, paradoxically given the abundance of oil and gas resources in the region, planning to develop coal-fired power plants using coal imported from outside.

- Electricity interconnectors are unlikely to be the optimal channel to trade energy because it is cheaper to export energy in bulk via pipeline and the demand for water and the use of multi-purpose power and water desalination plants makes it more attractive to generate electricity close to the population centres and to import natural gas (rather than to import the electricity in bulk).

- Furthermore, the trading arrangements developed for the GCC electricity interconnector and the size of the interconnector do not favour its use for trading bulk energy as electricity. The interconnector was designed primarily to allow the sharing of reserve and, once capacity is allocated for reserve sharing, there is limited spare capacity available to permit the trading of energy on a firm basis (ie., long-term firm contracts between an electricity producer in one country and a buyer in another). Given the advantages of direct trade in natural gas, this design of the electricity interconnector – primarily for reserve sharing rather than bulk energy trade – is likely to have been the optimal design for GCC members.

- The feasibility study to examine the benefits of the GCC interconnector selected the planned interconnector capacity in order to allow reserve sharing. The study is not publicly available. It is possible that reinforcement of the regional electricity network could yield net benefits, but an evaluation would require a full probabilistic analysis and it is impossible to judge without such an analysis. However, a study of the further reinforcement of the GCC interconnector should probably wait until the interconnector that is near to completion is fully operational and some experience has been gained.

- A study should be undertaken to help understand how the existing interconnector could be optimised to allow trade in non-firm energy to exploit differences in short-run fuel and operating costs among GCC members and differences in load patterns. Such analysis would require the use of multi-area dispatch simulation models.

10.7.2 Opportunities

The most feasible energy trading scenarios for the region would be the following:

- The primary strategy should be to maximise the utilisation of the existing gas pipeline linking Qatar with UAE and Oman. The pipeline can carry 32 BCM per year but only 20 BCM is contracted. Since UAE and Oman are both planning to develop power plants using imported coal, there are obvious benefits to utilising this capacity to the maximum and in order to minimise imports of energy from outside the region.

- Gas demand projections for UAE in Section 7.7 indicate that demand will double from 52 BCM in 2009 to 106 BCM in 2020. The demand for gas in Oman in the power sector is also expected to double though more modestly from 5 BCM in 2009 to 10 BCM in 2020. In total, an extra 60 BCM per year will be required and, unless UAE and Oman can expand their own production to meet this additional demand, the capacity of the existing Dolphin pipeline will quickly become fully utilised. Further expansion of the Dolphin pipeline would therefore be an obvious strategy.

- Another obvious strategy for regional trade is a pipeline linking Qatar with Bahrain and Kuwait, as planned by Dolphin Energy. If there continue to be difficulties in reaching agreement with Saudi Arabia over the pipeline between Qatar and Kuwait through Saudi Arabia's territorial waters, and if Kuwait cannot reach agreements with Iraq and Iran over gas imports, then Kuwait's main choice of primary energy supply from the region is the further expansion of imports of LNG from Qatar. Use of the electricity interconnector to provide bulk energy is likely to be problematic since it would depend on agreement with its neighbours on a fundamentally different use of the interconnector. Additionally, none of the GCC countries other than, perhaps, Qatar are likely to have sufficient spare generating capacity and energy resources to supply Kuwait in the near future.

- Another, complementary scenario, involves utilisation of gas reserves in the Empty Quarter of Saudi Arabia at Shaybah to supply gas to UAE and Oman. These are closer to Shaybah than Saudi Arabia's own load centres, and additionally prices paid by UAE and Oman for Saudi Arabia's gas should be more attractive than the official prices paid by Saudi Arabia itself.

- At a policy level, there are strong economic advantages from raising the prices paid for natural gas both to discourage the diversion of gas to energy-intensive export industries and to encourage the exploration and development of natural gas resources.

- Another strategy to minimise electricity generation costs within the region will be to exploit the GCC electricity interconnector to exploit differences in the marginal costs of electricity production on different systems at different times of the day.

11 Opportunities for trade: Yemen and Saudi Arabia

A study was undertaken in 2006-07 by Tractebel Engineering and CESI on behalf of the Governments of Yemen and Saudi Arabia entitled: *Consultancy Services for the Feasibility Study for the Saudi-Yemen Electrical Interconnection*. To our knowledge, no studies have been undertaken of natural gas pipelines connecting the two countries.

The Tractebel study and its conclusions are summarised in Section 11.1 below. The study was based on assumptions made at the time that natural gas was abundant in Yemen and that Yemen could export electricity to Saudi Arabia from its gas-fired power plants, but it is now clear that gas available for power generation in Yemen is constrained and the conclusions of the Tractebel study no longer apply. In Section 11.2 we therefore re-consider, to the extent possible, the economic justification for interconnection. Finally, in Section 11.3 we consider the possibilities of a natural gas pipeline connecting the two countries.

11.1 Saudi-Yemen electrical interconnection

11.1.1 Summary of Tractebel's study and conclusions

The proposed interconnector would involve a 416 km , 400 kV double-circuit AC line from Bani Hoshish to Kudmi, both in Saudi Arabia, and a back-to-back AC/DC converter station (required to convert between the 50 Hz system in Yemen and the 60 Hz system in Saudi Arabia) to connect Saudi Arabia with Yemen's main grid. The convertor station was to be built in phases with a 250 MW convertor to be commissioned in 2009 and then to be upgraded to 500 MW in 2013. The construction of the interconnector was assumed to start in 2007-2008 in order to have the first convertor in operation by 2009.

The total interconnector investment cost of US $331 million included the following three components:

- A back-to-back converter station (500 MW at US$170/kW) costing US$85 million;
- A 400 kV double-circuit AC line (US$0.5 million/km for flat terrain routing and US$1 million/km for mountain terrain routing yielding a weighted average cost of $0.584 million/km) with a total line cost of US$242.9 million; and
- An AC shunt reactor costing US$2.9 million.

As noted above, Tractebel concluded that such an interconnector would be justified in economic terms due primarily to the assumed abundance of natural gas in Yemen. The generation expansion plan of Yemen was based upon generating units fired with natural gas while the power plants in Saudi Arabia were assumed to be fuelled with crude oil. Using the marginal cost of gas production (US$1/mmbtu) and internationally traded price of crude oil in its economic analysis, Tractebel concluded that a large incentive exists for exporting "cheap" power from Yemen to Saudi Arabia involving large power transfers on the interconnector. However, the benefits from the interconnection depend critically upon:

- the amount of gas that is available for power generation in Yemen for export purposes; and
- that Saudi Arabia values the crude oil that is burnt within its power plants at internationally traded oil prices.

At the time the study was undertaken in 2006-07, Yemen was expecting to develop new gas-fired power plants to meet all of its power demand and still have enough gas available to supply industry and other users. However, since then the Yemen LNG project has become a reality and 9.2 tcf of Yemen's primary natural gas reserves (from Block 18 in the Ma'rib basin) has been ring-fenced for LNG. The liquefaction plant has now been completed and the LNG project is expected to begin shipping LNG in mid-2009. It is now clear that the remaining reserves available to supply power plants within Yemen is constrained and that there is certainly insufficient gas to allow Yemen to develop power generation capacity to allow substantial exports to Saudi Arabia.

Tractebel's study identified three sets of benefits from interconnection:

- Energy and power exchanges;
- Capacity exchanges; and
- Reliability revenues.

The Tractebel report did not clearly divide the quantitative benefits into these three categories but the primary benefit was associated with energy exchanges resulting from exports to Saudi Arabia of electricity generated in Yemen. The three types of benefit are re-visited below in the light of the revised assumption of natural gas availability.

11.1.2 Energy and power exchanges

"Energy and power exchanges" in the Tractebel report refer to fuel cost savings from optimal dispatch that exploits differences in variable fuel and operating costs of plants on the two systems and differences in load patterns. These benefits assume that the two systems continue to plan their investments independently (ie., not adopting an integrated planning approach).

Though gas supplies are clearly not now surplus in Yemen, nevertheless there could still be benefits relating to energy and power exchanges.

Until Yemen has commissioned a substantial gas-fired capacity, the Yemen power system will be using expensive diesel plants[72] and old, inefficient steam plants

[72] Including rented diesels.

burning heavy-fuel oil and this older plant could not economically displace generation in Saudi Arabia. Saudi Arabia might be able to supply load in Yemen more cheaply but until Saudi Arabia has comfortable surplus capacity it is unlikely that Saudi Arabia would want to connect the two grids because of the risk that it would have to support the Yemen system and jeapardise reliability on its own system, or isolate the Yemen system. An interconnector will therefore be unlikely in the short-term. However, by the time an interconnector could be built – perhaps 2014-16 at the earliest - it would be hoped that Yemen's power shortages would have been significantly reduced or eliminated and the prospects for fruitful power and energy exchanges may be worth investigating.

We, therefore focus on the medium term (from 2015 onwards) after the interconnector could feasibly be commissioned and when capacity shortages are likely to be less serious in Yemen and when Yemen will have commissioned substantial gas-fired capacity.

We note additionally, that Tractebel assumed that the opportunity cost of fuel used in Saudi Arabia's power plants would be its opportunity cost calculated as the net foregone export revenue. However, given that Saudi Arabia is clearly not a price taker in the international oil market and given that its exports of oil and petroleum products are voluntarily capped in order to maximise oil sector revenues, the opportunity cost of fuel used by its power plants to meet domestic electricity demand is probably much lower than net export revenue expected over the planning horizon of the project[73]. However, perversely, the economic value of fuel used in Saudi Arabia's power plants when these plants are used to supply electricity for export to Yemen is probably *higher* than the international market price. This is because it may lead to reductions in Yemen's imports of petroleum products which, in turn, will marginally reduce international market prices and reduce Saudi Arabia's revenues from oil and oil products. This latter affect is likely to be insignificant and can therefore be ignored, but it remains the case that:

- the economic opportunity cost of petroleum products used in Saudi Arabia's power plants to produce electricity for domestic consumption is low[74], and
- the economic opportunity cost of petroleum products used in Saudi Arabia's power plants to produce electricity for export is at least the international market price for petroleum products (net of the costs of transportation to the international market).

This creates a strong barrier to trade in electricity between Saudi Arabia and Yemen[75].

[73] It is the present value of foregone export revenue from oil that would be exported in the distant future when the Kingdom's exports begin to be supply constrained. Using reasonable discount rates, even with assumptions of increasing market prices for oil over time, this value is still low.

[74] See footnote 73.

11.1.3 Assessment of energy and power exchanges

As with all power systems, despite Yemen's current capacity constraints, in future there will be surplus capacity in Yemen in off-peak periods which could theoretically be used to export electricity to Saudi Arabia. Similarly, Saudi Arabia could export to Yemen during its off-peak periods. For example, there might be exports from Yemen to Saudi Arabia during the daytime peaks when air conditioning demand in offices is high in Saudi Arabia and there could be imports from Saudi Arabia to Yemen in the evening when Saudi Arabian demand has dropped below its peak. Similarly, Yemen might import from Saudi throughout the winter months when the Yemen load is relatively high and the Saudi load is relatively low.

If there were no constraint on gas reserves in Yemen then exports from Yemen to Saudi Arabia at Yemen's off peak periods might theoretically be possible. However, gas reserves in Yemen are constrained and it makes sense for Yemen to conserve its scarce gas resource to meet future domestic demand rather than use the gas to export electricity at what is likely to be a very low export price (because it will displace electricity produced in Saudi Arabia using fuel that has a low opportunity cost). The only reason that Yemen might wish to export off-peak electricity might be if gas production constraints in Yemen mean that gas utilisation has to be relatively constant throughout the year and interconnection of the power systems of Saudi and Yemen might give Yemen's gas-fired plants a higher plant load factor. Unfortunately, the upstream gas supply constraints in Yemen are currently unknown and it is impossible to assess whether this would be a benefit for Yemen. Even if it is a benefit to Yemen, it is not clear that the benefit would be sufficient to justify displacing fuel used in Saudi Arabia's power plants (which have low economic value to Saudi Arabia).

There is also some question as to whether there are benefits to either system from exporting electricity from Saudi Arabia to Yemen during the evening hours in the summer or during the winter months when Saudi Arabia's load is relatively low. This would typically require using open-cycle plants in Saudi Arabia burning crude oil or, in some cases, natural gas to displace Yemen's peaking plants which may be using natural gas or diesel plants burning heavy fuel oil or diesel. The economic value of fuel to Saudi Arabia in this case is the international price and when fuels are priced at economic levels there may therefore be little or no benefit to either party and, if there are benefits, these may be for relatively short periods.

11.1.4 Capacity exchanges

"Capacity exchanges" relate to the benefits of optimising the expansion of the interconnected system rather that least-cost development of two separate systems (ie., an integrated planning approach to the two power systems).

[75] This wedge between the economic value of petroleum products when used for exporting electricity and importing electricity, does not apply to other GCC states other than, perhaps, Bahrain, because these countries also have OPEC export quotas.

Quantifying the capacity exchange benefits requires a comparison of the net present value (NPV) costs of two separate least cost expansion plans with an integrated and re-optimised plan. The Tractebel study indicates that in the integrated system (ie., with the interconnector) more CCGT plant would be built in both Saudi Arabia and Yemen systems in preference to open-cycle gas turbines adopted when each system is planned independantly.

If the analysis were to be re-run there could be similar benefits but it is impossible to extract from the Tractebel study the quantity of these benefits separate from the energy trading benefits.

11.1.5 Reliability revenues

"Reliability revenues" relate to reductions in energy-not-served (load shedding) as a result of the interconnection. The Tractebel report makes it clear that the interconnector is not economic on the basis of reliability revenues alone but that it clearly could be a contributor to the overall benefits of the interconnector. Unfortunately, again, it is impossible to extract from the Tractebel study the quantity of these benefits separate from the energy trading benefits. However, Tractebel indicated that these benefits are relatively small and vary quite significantly from year to year.

11.1.6 Conclusions on the interconnection study

Two critical assumptions were made at the time the Saudi-Yemen Electrical Interconnection study was prepared:

- natural gas in Yemen would be abundant and its economic value was low,
- the economic value of oil used for power generation in Saudi Arabia was the international market price (net of transport costs).

It is now clear that the availability of natural gas for power production in Yemen is constrained and the economic value of natural gas is above US$3/mmbtu and rather than use this scarce resource by generating electricity for export to Saudi Arabia, Yemen should conserve gas for use in power generation in order to minimise imports of fuels in the near future.

It is also clear that electricity generated in Yemen using relatively expensive natural gas cannot compete with electricity generated in Saudi Arabia using oil (or natural gas) that have relativel low economic values in Saudi Arabia.

These revisions to the assumptions would fundamentally change the conclusions that interconnection is justified to allow the export of electricity to Saudi Arabia generated using Yemen's surplus natural gas. The Report does not separate the components of benefits associated with energy trade from the other benefits (capacity and reliability) and it is therefore impossible to use the report findings directly to assess whether an interconnector is viable for trade other than bulk energy. In any case, the changes to fuel availability and price will fundamentally impact upon the underlying least-cost expansion plan from which the economic benefits were derived. In Section 11.2 below we re-assess the costs and benefits of the interconnector to the extent possible with the information available.

11.2 Re-assessment of the Saudi-Yemen interconnection

An interconnector benefit not explicitly mentioned in the Tracebel report is the associated reduction in spinning reserve on both interconnected systems[76]. In practice, Yemen's electricity system has very little (if any) spinning reserve at present and any unit trips or other outages which will result in load shedding (ie., any benefit of interconnection would be associated with improved reliability). However, in future, an interconnector could provide spinning reserve benefits to Yemen, though given the disparity in size between the two and the fact that Saudi Arabia is already connected to other GCC countries, the spinning reserve benefit to Saudi Arabia will be small.

Given that the GCC interconnection study found that there are considerable benefits in interconnection of the GCC countries for the primary purpose of sharing reserve (standing reserve and spinning reserve), we considered whether the same level of benefit might arise for an interconnector between Yemen and Saudi Arabia and whether this benefit alone might justify an interconnector.

We begin by noting that Tractebel found that reliability revenue did not, by itself, justify the investment in the interconnector. The reason that Tractebel came to very different conclusions compared with the GCC interconnection study is that Tractebel has divided the benefits in a different way from the GCC study.

In the Saudi –Yemen study the benefits are defined under three categories (as described in Section 11.1 above):

- ❑ Energy & power exchanges
- ❑ Capacity exchange revenues
- ❑ Reliability revenues

The reliability benefits in the Tractebel study (the third component) only take into account the reduction in expected energy not served (EENS) as a result of interconnection and not the ability to defer new generation investment as a result of reserve sharing. The ability to defer new investment is embodied within the other two components (which are lumped together in the analysis). Strictly speaking, in systems that are optimally developed then the level of EENS would be the same, or almost the same, with or without the interconnector and the benefits would be measured in terms of lower reserve margins and lower aggregate investment requirments in an interconnected system. Tractebel's analysis has, however, assumed some short-term benefits of lower EENS after interconnection because the

[76] This benefit may be implicit within the least cost expansion plan if the planning software takes account of spinning reserve requirements when simulating plant dispatch.

two systems are assumed not to have the optimal level of aggregate capacity and therefore load shedding in the isolated systems is significantly higher than it should be. In particular, Yemen has a significant capacity shortfall until such time as new capacity is commissioned.

It is not possible to extract from the Tractebel analysis the benefits that are comparable with those of the GCC interconnection study and that are associated solely with deferred generation investment. The trading benefit associated with the assumed export of gas fired electricity from Yemen to Saudi Arabia obscure the benefits from deferred generation investment.

We note, however, that the benefit of the GCC interconnector was estimated to reduce the capacity investment requirement for phase 1 by 3,595 MW and the cost of the interconnector was US$1,095 million. The cost-benefit ratio was given as 1.77, implying a benefit of US$1,938 million equivalent to US$539/kW which we assume to be in present-value terms. The proposed Yemen – Saudi interconnector was rated at 500 MW while the maximum demand on the Yemen system is expected to be nearly 2,500 MW by 2015 (this is without the interconnection of the northern and eastern grids of Yemen). If we assume that the benefit to Yemen of interconnection with Saudi Arabia is similar in percentage terms to the benefit to Oman of interconnecting with GCC, then there will be a reduction in Yemen's required capacity by 6.4% times Yemen's peak demand. Assuming demand is 2,500 MW in 2015 then the capacity saving to Yemen would be 160 MW and if the avoided capital cost is similar to that estimated for GCC at US$539/kW then the monetary saving would be US$86 million[77]. This is considerably less than the estimated cost of the interconnector of US$225 million.

The capacity of the proposed interconnector between Yemen and Saudi Arabia was large relative to Yemen's maximum demand (500 MW capacity which is 20% of the forecast peak demand in 2015), which is a much higher percentage than that of Oman's interconnector relative to Oman's peak demand. This over-sizing of the Yemen-Saudi interconnector (at the time it was sized to allow energy trade) could help explain why the Oman interconnector was justified while the Yemen-Saudi Arabia one appears not to be. However, given the distances involved between the Yemen and Saudi Arabian grids, it would be difficult to adopt a smaller capacity transmission line and it may therefore be impossible to reduce the capital costs.

Given the disparity in size between Yemen and Saudi Arabia, the benefit to Saudi Arabia in terms of reduced reserve of connecting to Yemen is likely to be minimal – it may actually be increased if generation investment in Yemen fails to match demand and Saudi Arabia feels obliged to provide capacity as a backstop for this contingency. Overall, this suggests that the interconnector would not be justified or, as a minimum, the Tractebel study needs to be re-visited. However, as discussed in Section 13, further studies should be postponed until Yemen's power shortages are resolved.

[77] This is conservative since we believe the costs and benefits are in 2003 price levels.

11.3 Saudi-Yemen gas interconnection

Though the development of a natural gas pipeline connecting Saudi Arabia with Yemen has not, to our knowledge, been considered, this is a possibility. Saudi Arabia's Rub al Khali (Empty Quarter) is believed to contain natural gas reserves potentially as high as 8.4 trillion cubic meters, although these are not proven (the area remains under exploration). The South Rub al-Khali Company (SRAK), a consortium of Saudi Aramco and Royal Dutch/Shell, is exploring Shaybah and Kidan oil fields, abutting Oman and the UAE, and the Saudi-Yemeni border and hopes to produce 14 MCM/day of natural gas and condensate. Though we have no information on the technical difficulties in developing a pipeline connecting Yemen with these gas developments or the location of the potential fields under investigation, this could be a long-term opportunity. Given the location of the Rub al Khali relative to Yemen's own load centres, and given that the fields straddle the Yemen-Saudi Arabian border, a possible scenario might be that gas to the east of Yemen (not yet explored), bordering Saudi Arabia, is exported across the border to Saudi Arabia and combined with Saudi Arabia's gas to export across to UAE to join the regional gas pipeline.

12 Opportunities for trade: Yemen and Oman

12.1 Electricity

Difficulties of connecting Yemen's grids with those of Oman are clear from the map in Figure 28 in Section 9.4. Three grids in the Hadramaut (central) area of Yemen are currently isolated from each other and these, in turn, are isolated from the main grid to the west. Though recommendations have been made (see Section 9.4) to connect the three grids around Hadramaut and the coast to form an eastern grid and to interconnect the newly created eastern grid with the main western grid, neither the creation of the eastern grid nor the interconnection with the western grid have yet been included in future investment plans. Until Yemen's western and eastern grids are interconnected, given the distances involved and the limited size of Yemen's eastern grids, there would be very little benefit in interconnecting the eastern grid with Oman.

However, even when Yemen's western and eastern grids are interconnected the distances are such that interconnection of the Yemen grid with the Salalah grid (in the south of Oman) would almost certainly be uneconomic. As Figure 28 in Section 9.4 shows, the distance from the closest points on the eastern grids to the Oman border is over 400 km and the highest voltage for the transmission network proposed for Yemen's eastern grid is only 132 kV. A transmission line over this distance would require an extension of the 400 kV transmission line to Oman.

Within the southern part of Oman, the Salalah grid is relatively small with only approximately 50,000 customers and a peak demand of 260 MWin 2008. It has only recently added a network voltage of 132 kV whereas previously its transmission system was only 33 kV. A map showing the Salalah grid is not available but Salalah can be seen on the gas map in Figure 25 in Section 8.4. Even if one or other of Yemen or Oman were blessed with surplus energy resources[78], which they are not, there would be no economic logic in interconnecting the Salalah grid via a transmission line of over 400 km from Yemen's small eastern grid which, in turn, is a similar distance from Yemen's main western grid.

There would appear to be strong logic in connecting the Salalah grid with Oman's PDO grid since these are close to each other. The PDO grid, in turn, has an existing connection with the MIS grid in the north of Oman. The connection of Salalah with the PDO grid and the strengthening of the interconnection between PDO and the MIS Grid would create a unified national grid. However, we are not aware of plans for this.

Opportunities for supplying some isolated electrical loads in the east of Yemen (such as Al Mahrah Province on Yemen's far east) from the Omani system but the

[78] Both are blessed with energy resources and both are exporting gas as LNG, but LNG exports are committed and there is insufficient gas production available to meet domestic demand.

distances involved and the small loads in Al Mahrah would almost certainly make this uneconomic.

12.2 Natural gas

Oman's natural gas resources to the south of Oman are well developed and well utilised by PDO to meet its own power generation needs as well as for export. Oman does not have surplus gas resources that could be used to supply Yemen. Additionally, to the east of Yemen, in the provinces bordering Oman, population density and energy demand are extremely low. Given the absence of demand in Yemen and the absence of surplus supply in Oman, we believe that there can be no opportunities for exporting gas across the border from Oman to Yemen.

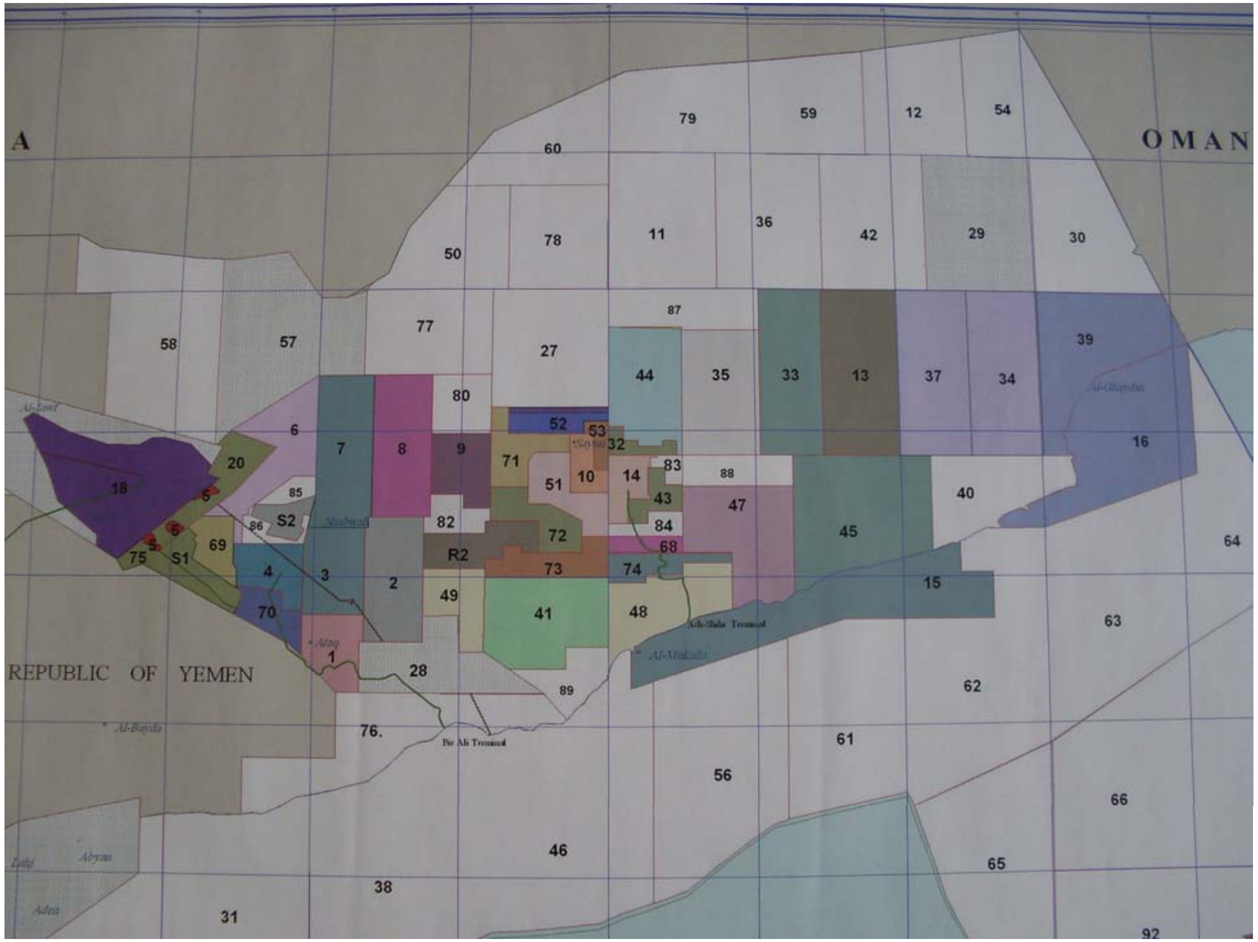
The reverse – the export of gas from Yemen's eastern provinces to Oman – might be feasible if gas production is economically justified. Currently, however, Yemen has no non-associated gas and, of the 100 oil blocks at various stages of exploration or development, only 12 blocks are producing oil. A high-level oil concession map for Yemen was shown in Section 9.1 and a more detailed map, focusing more on eastern Yemen, is shown in Figure 34 below.

The producing blocks are located in the two main basins:

- ❑ Ma'rib/Shabwah (located in the Ma'rib area), and
- ❑ Sayoun/Masila (located in the Hadramaut area).

The latter is closer to the main population centres in Yemen than it is to population centres in Oman and if gas production is justified then it would be produced for Yemen's own market. The former is much closer still to the Yemen population centres and, given Yemen's gas shortages and the distances involved (over 800 km), it would clearly be uneconomic to export of natural gas to Oman.

Figure 34 Detailed oil concession map – Yemen



Source: Petroleum Exploration and Production Authority. Uncoloured blocks have not been allocated.

Many of the remaining oil concession blocks to the east of Yemen, including the off-shore blocks, have not yet been taken up. Those that have been taken up are shown in Table 72. None are yet in producing oil (or natural gas).

Table 72 Yemen's eastern oil concessions

Exploration block/location	Operator/partners	No. of wells[79]	Bidding round[80]
Block 16 (Qamar), Al-Mahra Governorate, off-shore	KNOC, Samsung, Daesung, G. S. Holdings and YCO	4	(PSA approved 2006)
Block 29 (South Sanau), Al-Mahra Governorate	OMV (Yemen)	5	3rd
Block 34 (Jeza), Al-Mahra Governorate	Reliance, Hood Oil and YCO	1	2nd
Block 37 (Mahrait), straddles Al-Mahra and Hadramaut	Reliance, Hood Oil and YCO	1	2nd
Block 39 (Damqawt), Al-Mahra Governorate	KNOC, Samsung, Daesung, G. S. Holdings and YCO	1	2nd

Source: Petroleum Exploration and Production Authority website.

In conclusion, the Seyoun/Masila basin in the Hadramaut area of Yemen has natural gas available, but the area is closer to the main population centres in Yemen than it is to population centres in the south of Oman. If gas production is viable then it should be prioritised for Yemen's own market. The oil concession blocks to the east of Yemen may potentially contain natural gas in commercially recoverable quantities and Oman would be the natural market for this gas, but either the exploration rights to these fields has not yet been taken up by oil companies or, where they have, oil production and potential gas production is not expectedfor some time.

[79] As of August 2009.

[80] The second round occurred in 2004-05 and the results announced in July 2005. The third round occurred during 2006 and the results announced in December 2006.

13 Next steps

In Section 13 below, based on the assessments above, we:

- summarise in broad terms our understanding of whether further electricity and/or gas integration will benefit the GCC countries and Yemen,
- identify the data that needs to be collected or analysis that needs to be undertaken in order to understand whether integration would be beneficial,
- note the pre-conditions that may need to be satisfied to realise the benefits of integration.

We also consider the factors that these countries should consider when deciding on increased integration.

Finally, we mention additional trading possibilities between the GCC/Yemen region and other countries/regions.

13.1 Benefits of regional energy integration

Focusing exclusively on the net economic benefits of integration, and ignoring political constraints, the discussions in the Sections above suggest the following:

- There appear to be strong benefits in increasing the exports of natural gas by pipeline from Qatar to UAE and Oman and to develop exports from Qatar to Bahrain and Kuwait in order to fill the deficit of natural gas for power generation in these countries. Export of gas is likely to be preferable to the export of electricity because a) it is more cost effective to transport energy in bulk via natural gas pipelines than to transport it as electricity; b) in the GCC countries, power plants are often integrated with desalination plants and integrated power and water plants need to located close to population centres; and c) power plants distributed among the GCC countries with some dual fuel capabilities[81] will provide greater security of supply for individual GCC countries (though not for the GCC countries in aggregate).
- Opportunities may also exist for further developing Saudi Arabia's gas resources both to substitute for oil-based power generation within the country and for export of natural gas via pipelines to its neighbours such as Kuwait, UAE or Oman. Opportunities may exist in this regard for gas developments in the Empty Quarter in the south-east of the country.

[81] Gas turbine plants can, if appropriately designed or modified, burn natural gas, distillate or crude oil and, with some increase in maintenance costs and reduction in availability, heavy fuel oil.

- ❑ There may be opportunities to increase the capacity of the GCC electricity interconnection scheme in order to allow enhanced benefits of reserve sharing, exploitation of differences between systems in terms of short-run fuel and operating costs, and possibly trade in ancillary services.

- ❑ There appear to be few net benefits in linking Yemen and Saudi Arabia's electricity network for the purpose of trade in bulk energy. There could be potential for interconnection for reserve sharing benefits (similar to those expected to be achieved for the GCC electricity interconnector) and to exploit differences between the two systems in terms of short-run fuel and operating costs.

- ❑ There appear to be very few net benefits in developing gas pipelines or electricity interconnections linking Oman with Yemen.

13.2 Analysis necessary to confirm the net benefits

Below we consider the analysis necessary to confirm the net benefits from enhanced trade and the associated interconnections.

13.2.1 GCC gas pipeline network

The case for developing or expanding the gas pipeline network between Qatar and its neighbours appears overwhelming. It does not make economic sense for Qatar to export gas to the world as LNG, with all of the associated loss of value along the LNG supply chain (of around US$3/mmbtu[82]), while its close neighbours who could be supplied cheaply by pipeline for less than US$0.5/mmbtu are planning to develop power plants using coal imported from distant parts of the world.

If account is taken of the preference by countries that are signatories to the Kyoto agreement on climate change for natural gas to avoid greenhouse gas emissions, then some of these countries might be willing to pay a premium of up to US$1.4/mmbtu for natural gas (in whatever form) rather than coal at US$66/tonne. This assumes that the value of CO_2 emissions reduced is equal to the 'market' price of US$20/tonne[83]. GCC countries do not face such concerns about CO_2 emissions and might therefore be more willing to burn coal than would Kyoto signatories – or equivalently, willing to pay a lower price for natural gas. If account is taken of the willingness of some Kyoto signatories to pay a premium of up to US$1.4/mmbtu for natural gas, this would mean that instead of losing US$3/mmbtu along the LNG supply chain, Qatar would lose only US$1.6/mmbtu[84]. This is, however, still a

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[82] The calculation is derived from netback calculations in: *Yemen: Gas Incentive Framework, Determining the Economic Value of Gas*; World Bank, October 2006.

[83] In 2009 the market price in Europe is about 60% of this level.

[84] ECA calculation. Without a value on CO_2 emissions, the price of natural gas would need to exceed US$5.4/mmbtu before it becomes cheaper to burn coal at US$66/tonne in a steam plant in preference to natural gas in a CCGT plant. With a CO_2 value of US$20/tonne, the breakeven price of natural gas

significant loss compared with exporting gas to a neighbouring country via pipeline.

The failure to develop an expanded gas pipeline network has arisen, we believe, partly because of short-term factors – the moratorium on further gas exports from Qatar – as well as political factors discussed in Section 13.3 below.

13.2.2 Gas exports from Saudi Arabia

In Saudi Arabia, as with all GCC countries[85], substantial opportunities to develop natural gas resources are believed to exist but are are stymied by domestic natural gas pricing policies.

Given the low domestic pricing policies for gas, there are inevitably few champions for gas development among the upstream companies responsible for development of gas resources. To verify the potential for the exploitation of natural gas reserves in Saudi Arabia and other GCC countries, integrated gas and power development plans are needed. This requires coordination between the ministries responsible for oil and gas and the ministries responsible for electricity and water. Currently, power development plans appear to be prepared independently of gas development plans (this was the case in Yemen and in Saudi Arabia) and when attempts are made to implement the power development plans using natural gas, the gas is not always available. In Saudi Arabia, for example, under a Royal Decree issued in 2006, some of the country's largest power plants that were initially planned to run on gas will, instead, be fuelled with crude oil. In Yemen, while an integrated power and gas development plan was prepared in 2001, the plan focused primarily on the downstream gas pipelines and power system and ignored the upstream.

Though the development of coordinated power and gas development plans will not guarantee the availability of natural gas (unless domestic prices for gas are increased), nevertheless it will help ensure that all the involved parties are involved in gas development planning and are aware of their responsibilities in relation to gas developments.

13.2.3 Enhancement of the capacity of the GCC interconnector

A study to analyse the benefits of further reinforcement of the GCC electricity interconnector may be worthwhile but should probably wait until the interconnector currently close to completion is found to be used to its maximum potential. It would be premature to re-evaluate the capacity of the interconnectors until the current scheme is fully operational and some experience has been gained.

There would, however, be benefit in attempting to understand how the existing interconnector could be used to maximise the short-term trade in non-firm

increases to US$6.8/mmbtu. A country that is a signatory to the Kyoto agreement, without access to other sources of low carbon fuels, might therefore be willing to pay US$1.4/mmbtu more for gas than, say, UAE or Oman.

[85] Except Qatar which, though it has low domestic prices, has developed its gas resources for export.

electricity in order to exploit differences in short-run fuel and O&M costs among GCC members. Such a study would require analysis using a multi-area dispatch simulation and optimisation model such as SDDP, GTMAX, MAPS or Promod IV[86]. To make the analysis worthwhile, cooperation would be needed among GCC states to provide the full data on load shape, current and committed plants, heat rates, economic costs of fuel, constraints on fuel use (eg., take–or-pay agreements and constraints on the reallocation of natural gas across time and between plants).

13.2.4 Yemen-Saudi Arabia interconnector

To re-assess whether the Yemen-Saudi Arabia interconnector is economically justified, the 2008 study prepared by Tractebel would need to be re-run to analyse the reserve-sharing and other benefits of such an interconnector. The study would need to be based on current information on the availability and economic price of natural gas in Yemen and the economic value of fuels in Saudi Arabia.

The sizing of the interconnector should also be re-visited in the study since the size proposed by Tractebel was designed for trade in bulk energy and would be too large if a more limited reserve sharing role is anticipated.

However, it is almost inconceivable that Saudi Arabia and other GCC members would agree to interconnect the systems for reserve sharing while Yemen continues to suffer chronic power shortages. Further investigations of the interconnector should therefore be postponed until Yemen's power shortages are resolved.

13.3 Pre-conditions necessary to realise the benefits

13.3.1 Political constraints

Political constraints, notably objections from Saudi Arabia to a pipeline through its territorial waters, have been a factor in delaying the development of natural gas pipelines from Qatar to Bahrain and Kuwait. Such objections would need to be overcome to allow stronger regional integration of natural gas networks.

13.3.2 Natural gas pricing policy

Prices for natural gas in some GCC countries in 2007 and 2008 are shown in Table 73 and Table 74 respectively. These prices are well below the level believed to be necessary to justify the development of natural gas on a commercial basis – believed to be approximately US$4/mmbtu[87].

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[86] Developed by PSR Inc, Argonne National Laboratory, GE Software and New Energy Associates respectively.

[87] *Prospects for Energy Integration in the GCC: An Analysis of the GCC Energy Sector*; Research Seminar-Dubai School of Government, March 3, 2009; Justin Dargin, Dubai Initiative-Harvard University.

Table 73 GCC domestic gas feedstock prices, 2007	
Country	**Price (US$/mmbtu)**
Oman	0.35
Qatar	0.90
Saudi Arabia	0.75
UAE	0.75

Source: IEA: Natural Gas Market Review 2007.

Table 74 Gas prices in GCC countries, 2008	
Country	**Price (US$/mmbtu)**
Qatar (Industrial sector)	0.50
Saudi Arabia	0.75
Kuwait	0.80
Oman[88]	0.85
UAE	1.00-1.50
Bahrain	0.75-1.00

Source: Middle East Gas Revolution and West-East LNG Flows: Investment Challenges. 7th Doha Natural Gas Conference By Dr. Fereidun Fesharaki, Chairman, Shahriar Fesharaki, Vice Chairman, FACTS Global Energy, March 9-12, 2009, Doha, Qatar

Reform of natural gas pricing policies is a necessary precondition for a fuller development of natural gas resources in the GCC countries both for consumption within the country and for export to neighbouring countries.

13.3.3 Optimal use of the GCC electricity interconnector

The GCC electricity interconnector was designed primarily for reserve sharing but could be used for other purposes, including trade in non-firm energy. A precondition for the optimal use of the GCC electricity interconnector is the design of trading arrangements that are favourable to trade in non-firm energy.

The trading arrangements have not yet been published and it is too early to comment on whether this precondition has already been met.

[88] agreed price for major industrial projects at Sohar and Salalah regions

13.3.4 Reliability of power supply in Yemen

It is impossible that Saudi Arabia would be willing to interconnect its electricity network with Yemen for the purposes of reserve sharing. Even if an interconnector between the two is designed only to operate for reserve sharing, given the current chronic shortages of power in Yemen, such an interconnector would inevitably mean almost continuous flows of power from Saudi Arabia to Yemen. This would exacerbate Saudi Arabia's ongoing difficulties in developing new capacity fast enough to meet growing demand. It is therefore urgent that Yemen commissions enough capacity to meet its own demand before an interconnector could be considered for reserve sharing or for non-firm energy trade. To give Saudi Arabia and other GCC members sufficient confidence to allow it to connect the two systems, Yemen would also need to demonstrate a reasonable track record in maintaining a reasonably acceptable reserve margin.

13.4 Other trading possibilities

A possible interconnection between Yemen and Djibouti was removed from the Terms of Reference for this study. The expectation, when an interconnection between the two was first suggested, was that Yemen would export electricity to Djibouti using what was then abundant natural gas. Since then, with the commissioning of the Yemen's LNG export project, Yemen's gas resources are scarce and the country will need to consider power generation investments that do not use natural gas. Yemen is also desperately short of natural gas. An opportunity may therefore arise for Yemen to import electricity from Ethiopia and the East-African Power Pool through Djibouti. Ethiopia and Djibouti are already interconnected and Ethiopia is developing its extensive hydropower resources deliberately for export. A serious opportunity may therefore exist to import electricity to Yemen.

A final feasibility study is under preparation for an interconnection between Saudi Arabia and Egypt. This will include a 500kV HVDC link in two phases of 1,500 MW each which is planned to be operational in 2012 and 2015. The intention is that Egypt will import electricity from Saudi Arabia.

Annexes

A1 Earlier demand forecast for Saudi Arabia

The following Table describes an electricity demand forecast prepared for Saudi Arabia in 2006. This is not the latest forecast but it is the forecast which is associated with the power investment plan described in Section 4.6.

Table 75 Earlier electricity demand forecast – Saudi Arabia by operating area

Year	COA		EOA		WOA		SOA	
	Demand (MW)	Energy (GWh)	Demand (MW)	Energy (GWh)	Demand (MW)	Energy (GWh)	Demand (MW)	Energy (GWh)
2008	10,369	54,953	10,440	68,225	9,478	53,884	2,410	14,378
2009	10,879	57,655	10,953	71,579	9,944	56,533	2,529	15,085
2010	11,148	60,447	11,287	75,045	10,409	59,270	2,651	15,815
2011	11,662	63,238	11,808	78,511	10,890	62,008	2,774	16,546
2012	12,177	66,030	12,330	81,977	11,371	64,745	2,896	17,276
2013	12,692	68,822	12,851	85,443	11,851	67,482	3,018	18,007
2014	13,207	71,613	13,372	88,909	12,332	70,220	3,141	18,737
2015	13,704	74,311	13,876	92,258	12,797	72,865	3,259	19,443
2016	14,202	77,009	14,380	95,607	13,261	75,510	3,378	20,149
2017	14,699	79,707	14,883	98,956	13,726	78,155	3,496	20,855
2018	15,197	82,404	15,387	102,306	14,190	80,801	3,614	21,560
2019	15,694	85,102	15,891	105,655	14,655	83,446	3,732	22,266
2020	16,144	87,542	16,346	108,684	15,075	85,838	3,839	22,905

Source: Revised final report updated generation planning for the Saudi electricity sector, Prepared for Electricity & Cogeneration Regulatory Authority (ECRA) Riyadh, Saudi Arabia, by Centre for Engineering Research, Safar 1427 H March 2006.

The peak demand and sales forecasts for Saudi Arabia in aggregate for the interconnected and isolated networks are shown in Table 76.

Table 76 System peak demand and energy forecast - Saudi Arabia aggregate

Year	Demand (MW)	Sales (GWh)
2008	33,930	198,766
2009	35,399	207,917
2010	36,932	217,488
2011	38,531	227,501
2012	40,199	237,974
2013	41,940	248,930

Year	Demand (MW)	Sales (GWh)
2014	43,479	258,061
2015	45,073	267,526
2016	46,727	277,339
2017	48,441	287,512
2018	50,218	298,058
2019	51,652	306,568
2020	53,126	315,322

Source Updated generation planning for the Saudi electricity sector, 2006, as for Table 75. Forecasts were provided for 2008, 2013, 2018 and 2023. Intermediate years were interpolated by the Consultant.

A2 Electricity interconnection study – Saudi Arabia

Though the focus of the study is on interconnections between countries, we nevertheless consider the implications of interconnecting Saudi Arabia's operating areas. These interconnections were studied by the Centre for Engineering Research[89] in the power development planning study described in Section 4.6. The study considered interconnecting the Western Operating Area (WOA) with the Central Operating Area (COA) and the Southern Operating Area (SOA). The interconnectors and their assumed capacity are summarised in Table 77. COA and EOA are already interconnected by 230 kV and 380 kV overhead lines and there are plans to interconnect the systems still further as described in Section 4.4.

Table 77 Interconnections between operating areas – Saudi Arabia

Link	Year	Capacity (MW)	Connecting points	Notes
WOA - COA	2011	1,400	Muzahimiyah in COA and Bahra in WOA	±500 kV bipolar DC line
WOA - SOA	2014	800	Shaiba in WOA and Ash Shuqaiq in SOA	380 kV double circuit AC line

Source: *Revised final report updated generation planning for the Saudi electricity sector, Prepared for Electricity & Cogeneration Regulatory Authority (ECRA) Riyadh, Saudi Arabia, by Centre for Engineering Research, Safar 1427 H March 2006.*

The study estimated the benefits of interconnection in the same way that the benefits of the GCC interconnection were estimated – based on reserve sharing. The study team recognised that benefits could also arise from transfers between the EOA and the other operating areas because the EOA has larger and more efficient plants and that overall costs could be lower if plant in the EOA were used at a higher plant capacity factor – but this benefit was not calculated. The estimated savings from the creation of a unified grid linking the four operating areas are summarised in Table 78 (these assume that EOA is already interconnected to the GCC interconnected grid in 2008) and indicate a potential saving of 3,158 MW of capacity by 2023, or almost 10%.

[89] *Revised final report updated generation planning for the Saudi electricity sector, Prepared for Electricity & Cogeneration Regulatory Authority (ECRA) Riyadh, Saudi Arabia, by Centre for Engineering Research, Safar 1427 H March 2006.*

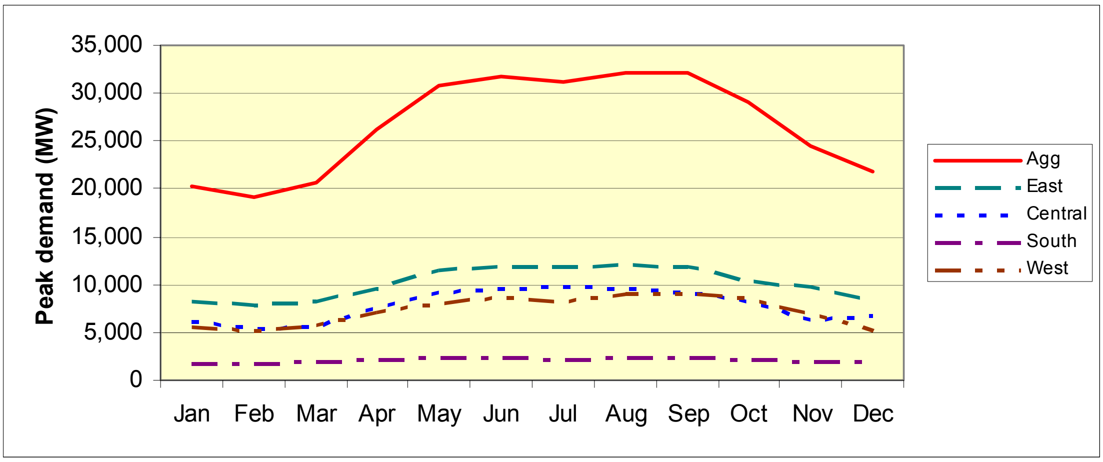
Table 78 Generation investments in unfied grid – Saudi Arabia

Area	Reference Plan (MW)	Unified grid (MW)	Savings (MW)	Units saved
EOA	7,175	6,175	1,000	8x125GT
COA	10,556	9,628	928	8X116GT
WOA	9,121	8,506	615	5X123GT
SOA	5,313	4,698	615	5X123GT
Total	*32,165*	*29,007*	*3,158*	-

Source: *Revised final report updated generation planning for the Saudi electricity sector, Prepared for Electricity & Cogeneration Regulatory Authority (ECRA) Riyadh, Saudi Arabia, by Centre for Engineering Research, Safar 1427 H March 2006.*

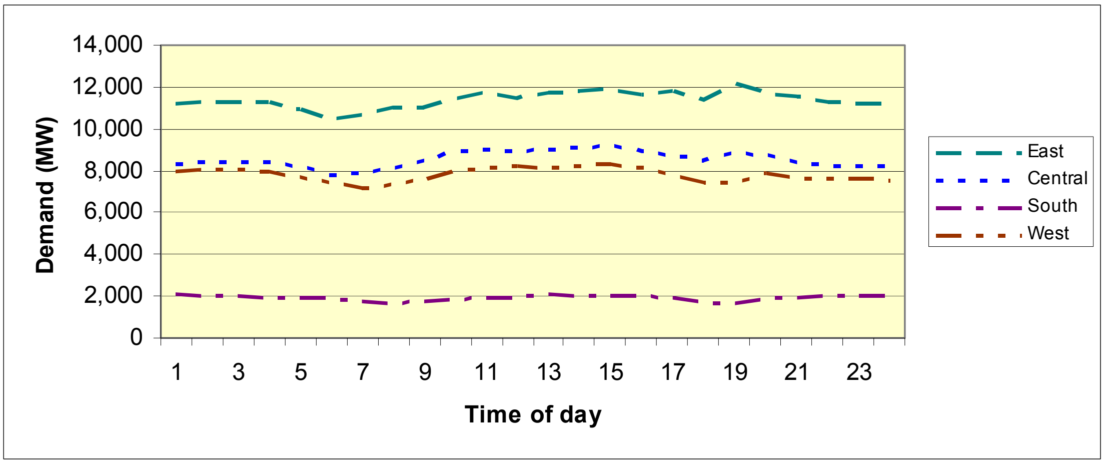
As with the GCC interconnector, Saudi Arabia's operating areas have similar load patterns as indicated in Figure 35 and Figure 36. Only the Southern operating area might have a seasonal pattern that differs from the other operating areas (flatter), but this operating area is small in relation to the total.

Figure 35 Seasonal load pattern in Saudi Arabia's operating areas (2006)



The four operating areas have slightly different daily load patterns, with EOA having a small evening peak with the other three having day-time peaks. We understand that load in the EOA is, surprisingly, dominated by industry while the other three operating areas are dominated by residential demand. In aggregate (not shown in Figure 36), the peak occurs in the daytime.

Figure 36 Daily load pattern in Saudi Arabia's operating areas



Load for August 15, 2006. This was the day of maximum demand for the system in aggregate.

The analysis conducted by the Centre for Engineering Research suggests clear benefits to interconnection within Saudi Arabia. These benefits may be higher if it were to be assumed that the interconnectors allows that plants with the lowest fuel operating costs to be dispatched first wherever they are located. This would probably imply flows from EOA to the other, smaller, areas.

A3 Gas flaring

Kuwait, Saudi Arabia and Qatar are among the 20 countries worldwide with largest amounts of gas flared according to GGFR. In Kuwait and Oman there were notable reductions recently while in Saudi Arabia and Qatar the amounts increased between 2005 and 2007.

Table 79 Estimated gas flaring (BCM)

	2005	2006	2007
Kuwait	2.5	2.5	2.1
Saudi Arabia	3.0	3.3	3.4
Bahrain	not available	not available	not available
Qatar	2.7	2.8	2.9
UAE			0.9[90]
Oman[91]	2.5	2.2	1.9
Yemen	not available	not available	not available

Source: Global Gas Flaring Reduction partnership (GGFR) unless stated otherwise in footnotes.

[90] http://www.ngdc.noaa.gov/daymsp/interest/gas_flares.html

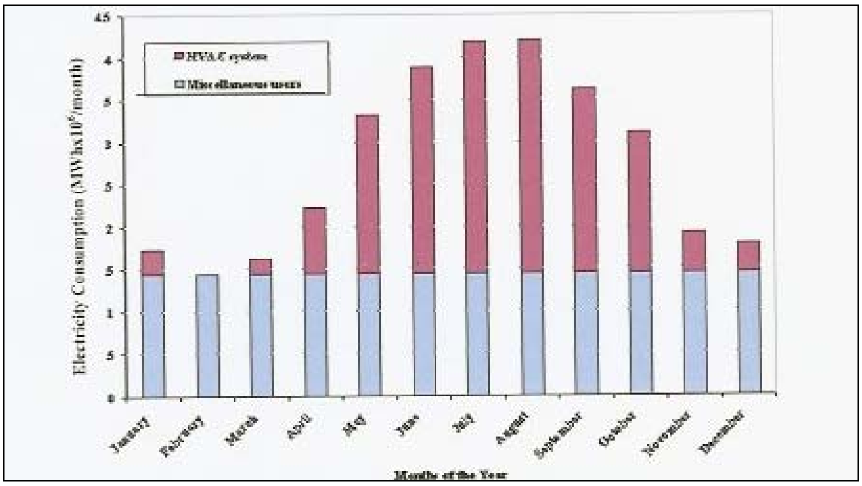
[91] Note that data in the table based on GGFR are higher than the volumes reported by Government.

A4 Electricity load patterns

A4.1 Kuwait

Electricity consumption in Kuwait peaks in July and August as shown in Figure 37.

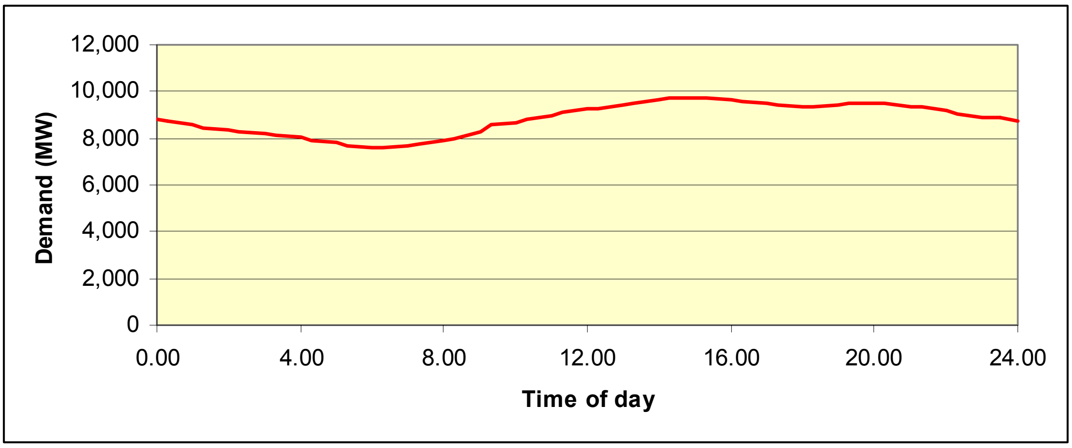
Figure 37 Monthly Electricity Consumption, 2003 - Kuwait



Source: Energy conservation program in Kuwait: a local perspective. Ali Hajiah, Kuwait Institute of Scientific Research, 2005

A daily load curve for Kuwait is shown in Figure 38 indicating a peak during the mid afternoon.

Figure 38 Daily load on the day of maximum demand, 2008 - Kuwait

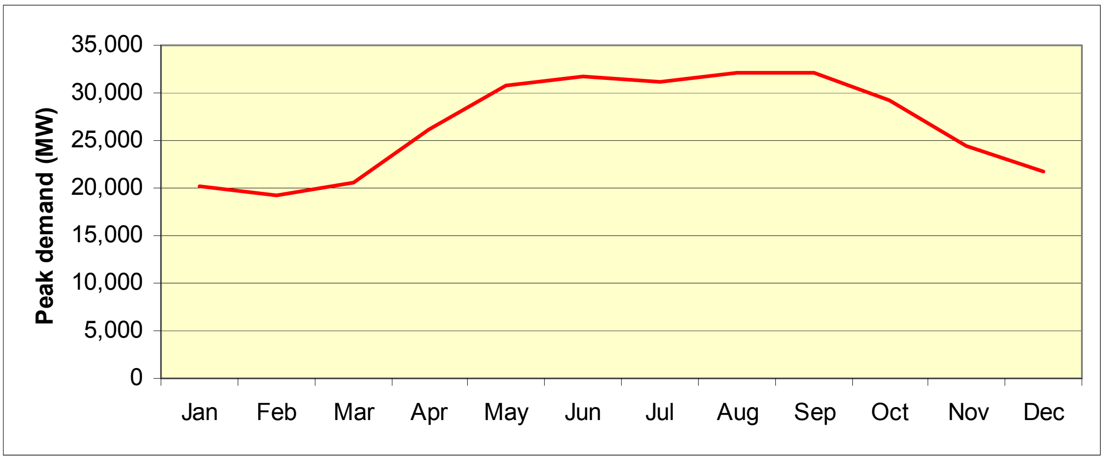


Source: ECA chart derived from data provided by the Ministry of Electricity.July 27 2008.

A4.2 Saudi Arabia

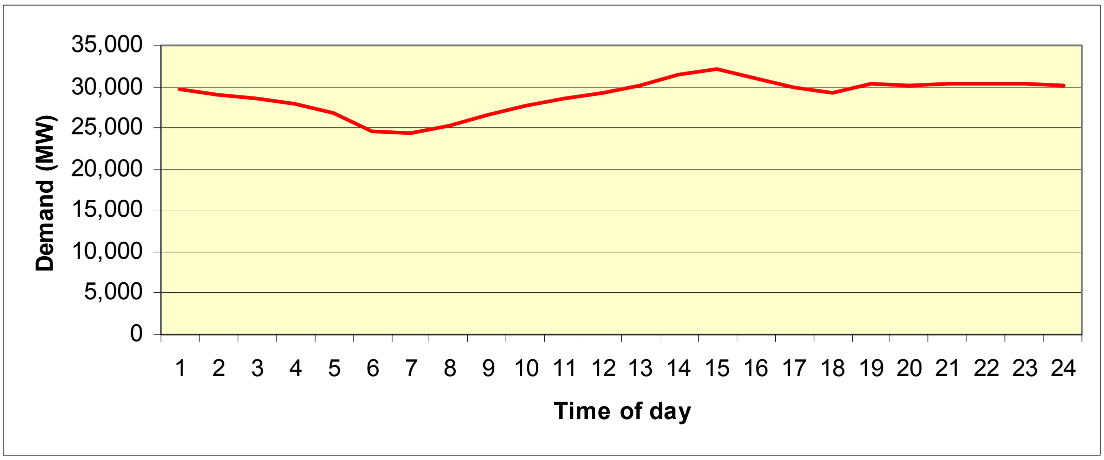
Seasonal and daily load profiles for Saudi Arabia are shown in Figure 39 and Figure 40. The daily load curve is aggregated from the four operating areas for the day of maximum demand in 2006 (10 September)

Figure 39 Seasonal load profile, 2006 - Saudi Arabia



Source: ECA chart using data supplied by Ministry of Electricity.

Figure 40 Daily load curve – Saudi Arabia

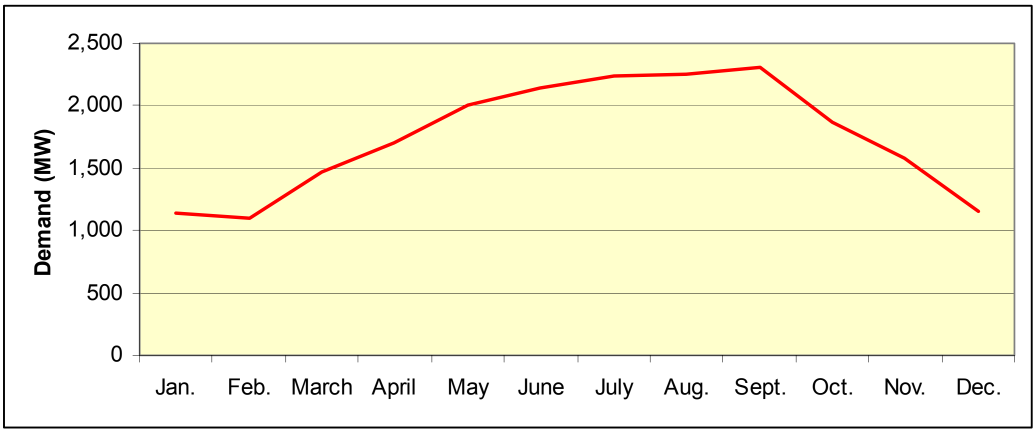


Source: ECA chart using data supplied by Ministry of Electricity for 2006.

A4.3 Bahrain

The peak demand in electricity in 2008 was registered in September - at 2,314 MW. Figure 41 indicates that the system peak occurs during July- September.

Figure 41 Monthly peak load (2008) - Bahrain



Source: ECA chart derived from data provided by Bahrain Ministry of Electricity and Water

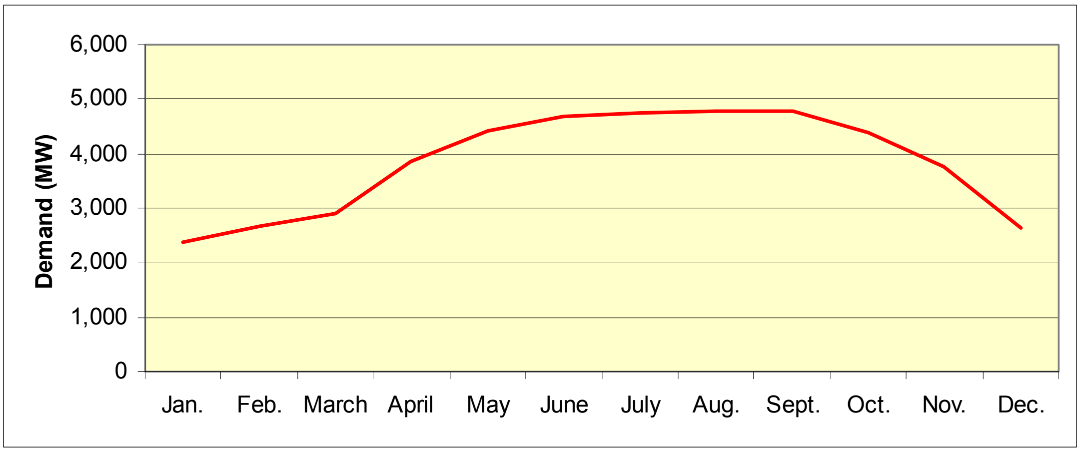
A4.4 Qatar

The load on the electricity network in Qatar in peak summer months is the heaviest between 1pm and 3pm. A second peak occurs between 6pm and 8pm because of the use of electrical appliances by households. Load curves are not available for Qatar.

A4.5 United Arab Emirates

The UAE's electricity demand shows extreme seasonal variation, with demand for power doubling in the summer, primarily because of the extensive use of air conditioning. In future this problem might improve as rising industrial demand (which has a flatter annual demand than the residential / commercial sectors that currently dominate demand) may flatten the annual demand curve. The monthly loads for Abu Dhabi, the largest of the Emirates, is shown in Figure 42.

Figure 42 Monthly electricity demand, ADWEC 2006 - UAE

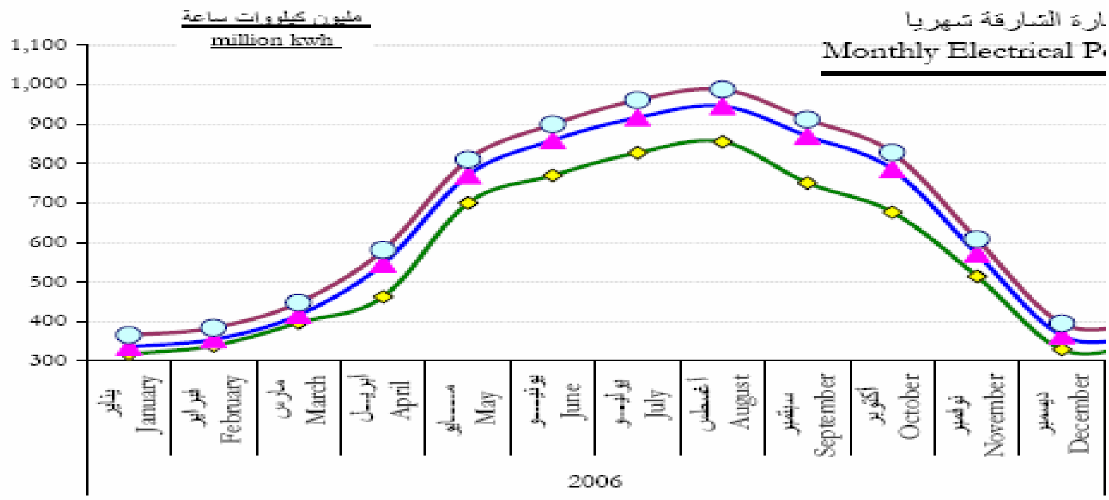


Source: ECA chart based on ADWEC data from www.adwec.ae

In 2007, the peak electricity demand in the Emirate of Abu Dhabi was 5,286 MW, on 2 September excluding peak exports to Dubai and Sharjah of 907 MW.

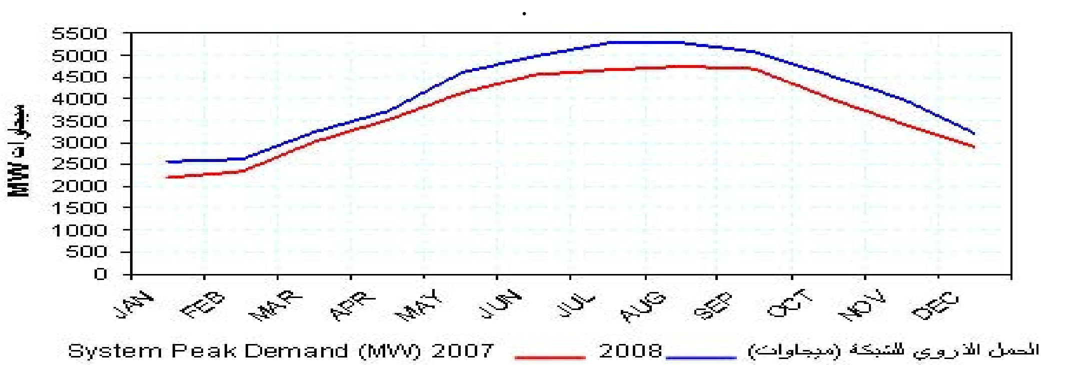
Monthly electricity loads in SEWA in Sharjah have a more pronounced seasonal shape than in Abu Dhabi - in contrast to DEWA (Dubai), where the curve is flatter (see Figure 43 and Figure 44).

Figure 43 Monthly electricity load - SEWA, UAE



Source: www.sewa.gov.ae. The three curves, from bottom to top, represent sold power, sent-out power and generated power respectively.

Figure 44 Montly electricity load - DEWA, UAE



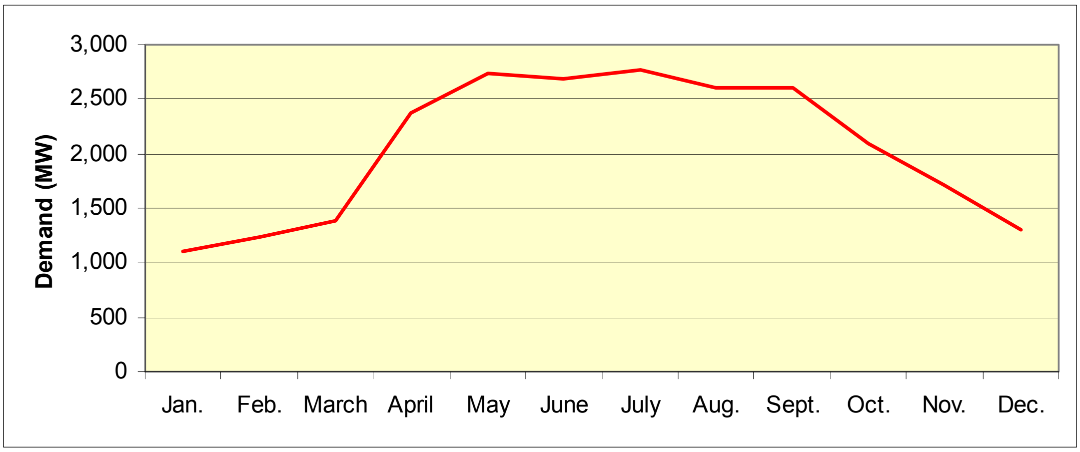
Source: www.dewa.gov.ae

A4.6 Oman

The MIS electricity demand has a distinct seasonal shape, with demand in summer months significantly higher than in winter.

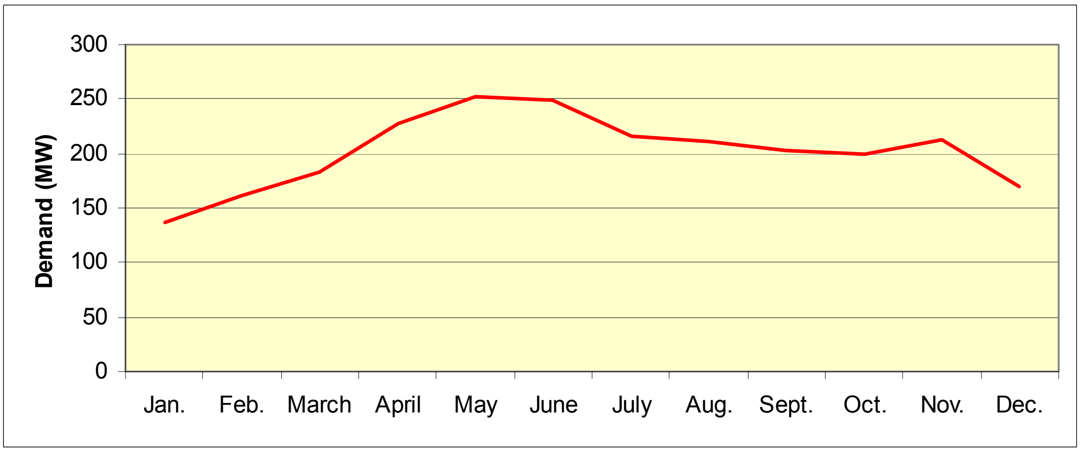
Residential customer demand has a significant influence on the MIS load shape. Air conditioning loads in summer rise in response to higher temperatures, resulting in the strong positive correlation of monthly peak demand and maximum monthly ambient temperature.

Figure 45 MIS peak demand 2007, Oman



Source: ECA chart from data in Oman Authority for Electricity Regulation, 2007 Annual Report

Figure 46 Salalah peak demand 2007, Oman



Source: ECA chart from data in Oman Authority for Electricity Regulation, 2007 Annual Report

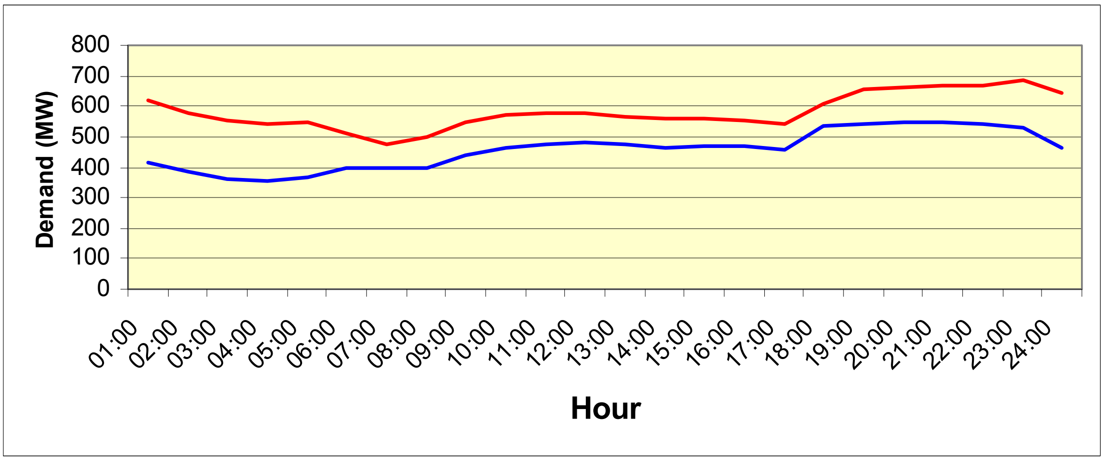
Peak hours occur during the day time but the variation through the 24 hours is not as great as in other GCC countries. In the winter there is a small peak at 8pm[92].

A4.7 Yemen

The daily load patterns for a Sunday in January and a Sunday in August (on the day of the system peak demand) in 2006 are shown in Figure 47. This suggests that the pattern is relatively constant throughout the year.

[92] Authority for Electricity Regulation, Oman, "Study on Renewable Energy Resources, Oman'', Final Report, May 2008, COWI and Partners LLC www.aer-oman.org/pdf/studyreport.pdf

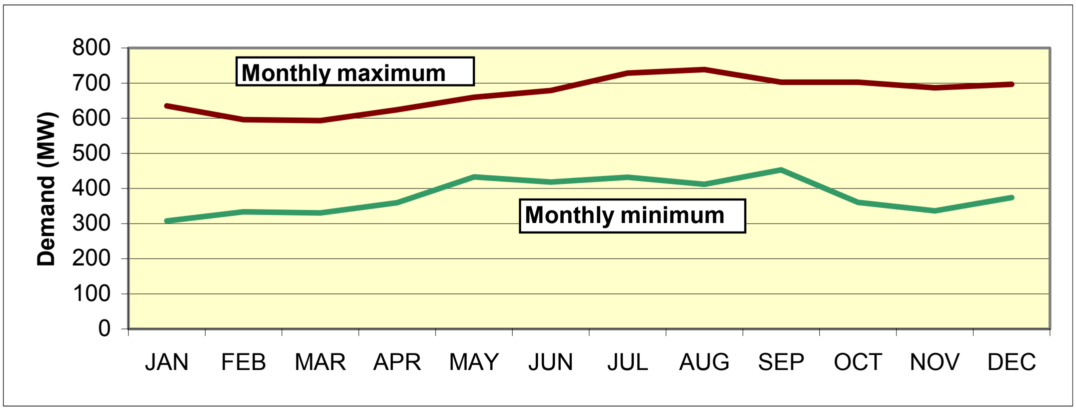
Figure 47 Daily load curves: January and August – Yemen



Source: ECA chart from PEC load data – adjusted for load shedding.

Seasonally the temperatures in highlands areas, including Sana'a, are relatively constant though there is significant seasonal variation in temperatures in the coastal load centres of Al Hodeidah, Taiz and Aden. The load pattern for the main grid in 2006, adjusted for load shedding, shown in Figure 48 indicates that there is relatively little seasonal variation in demand.

Figure 48 Seasonal load pattern (2006) – Yemen



Source: ECA chart, using data provided by PEC