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Power Sector Note

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ESMAP
Energy Sector Management Assistance Programme

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Abbreviations and Measures

(Exchange Rate Effective January 9, 2007)

Currency Unit - Iranian Rial

US$ 1 = IR 9,000

FISCAL YEAR

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ABBREVIATIONS AND ACRONYMS

AEDC	Alexandria Electricity Distribution Company
AFP Program	Mexico's Program for Energy Savings in Federal Buildings
bcm	Billion cubic meters
BOO	Build Own Operate
BOT	Build Operate Transfer
CCGT	Combined Cycle Gas Turbine
CFL	Compact Fluorescent Lamp
CO2	Carbon Dioxide
CONAE	Mexico's National Commission for Energy Conservation
CRERA	Center for Renewable Energy Research and Applications
DSM	Demand-side Management
ECA	Energy Conversion Agreements
ELI	Efficient Lighting Initiative
EMRB	Electricity Market Regulatory Board
ESCO	Energy Service Company
EUEMC	Energy and Urban Environment in Mediterranean Countries
FIPPA	Foreign Investment Promotion and Protection Act
FYDP	Five Year Development Plan
GDP	Gross Domestic Product
GMC	Generation Management Company
GoI	Government of Iran
GW	Gigawatt
GWh	Gigawatt hour
ICRG	International Country Risk Guide
IEA	International Energy Agency
IGMC	Iran Grid Management Company
IPP	Independent Power Producer
kV	Kilovolt
LNG	Liquefied Natural Gas
LPG	Liquified Petroleum Gas
LSE	Load Serving Entity
m^3	Cubic meters
MCM	Million Cubic Meter
mmbtu	Million British Thermal Units
MoE	Ministry of Energy
MoO	Ministry of Oil
MOU	Memorandum of Understanding
Mtoe	Million ton of oil equivalent
MW	Megawatt
NIGC	National Iranian Gas Company
NYISO	New York Independent System Operator
O&M	Operations and Maintenance
OECD	Organization for Economic Cooperation and Development
PPA	Power Purchase Agreement
PSP	Private Sector Participation
RECs	Regional Electricity Companies
RPS	Renewable Portfolio Standards

SABA	Iran Energy Efficiency Organization
SO	System Operator
SPP	Small Power Producers
SUNA	Iran Renewable Energy Organization
T&D	Transmission and Distribution
TREC	Tehran Regional Electricity Company
TWh	Terrawatt hour
US¢	US cents

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Preface

The Fourth Five Year Development Plan[1] sets the stage for important reforms of the power sector in Iran, some of which are now being implemented. In establishing the reform path, the Government of Iran (GoI) has reviewed alternative models from around the world and has incorporated lessons learned. The reforms are aimed at increasing the efficiency of the sector, both from a technical and commercial point of view. To facilitate the reforms, the industry has been unbundled and key institutions important for a liberalized market to function have been established, including a regulatory body and a market/system operator.

In June 2005, the World Bank was invited by the Government of Iran to engage in a dialogue on reform of the power sector, as well as to identify areas of cooperation. It was agreed that a Power Sector Note would be prepared which would review some of the key challenges in the sector, identify the strategic implications of the challenges, document international experience and provide a viewpoint on next steps[2]. In January, 2006, a workshop was held in Tehran to discuss private sector participation in the power sector and the development of a power exchange. During this workshop, the World Bank presented international lessons learned and was further informed of the Government's plans for reform. Through this dialogue, a number of areas of cooperation are emerging. These include Bank support to reinforce the transmission and distribution networks (given their important role as the backbone of the power system); technical assistance for price reforms, development of the power pool and private sector participation in generation; and assistance to step up energy efficiency. This cooperation will be presented in the Country Assistance Strategy (CAS) for Iran currently under preparation.

[1] Management and Planning Organization (2005) "Law of the fourth economic, social and cultural development plan of the Islamic Republic of Iran, 2005-2009 (1384-1388)" enacted on September 1, 2004.

[2] The Note is structured around 7 Chapters. In Chapter 1, demand for electricity is presented, including a description of the drivers of demand and the economic impact of reduced demand. Chapter 2 presents current supply strategies, with a focus on thermal power production and the impact of the subsidized natural gas that is available to the sector. The options considered are only those currently operational and therefore excludes nuclear, geothermal, etc. Chapter 3 presents Iran's potential for renewable energy and for stepping up energy efficiency measures. In Chapter 4, the financial performance of the sector - through the holding company Tavanir - is presented, including some estimates of the subsidies to the sector caused by below-cost recovery electricity tariffs. Chapters 5 and 6 review the Government's plans for the introduction of competitive electricity market and private sector participation; compares the plans to international experience; and identifies important next steps to realize the plans. Finally, in Chapter 7, the legal and regulatory framework that underpins the market development and private sector participation plans is presented and analyzed.

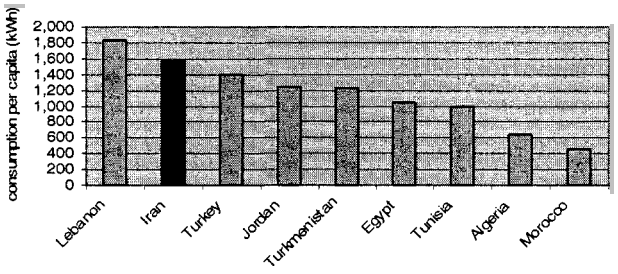
Executive Summary

Over the past decade, the Iranian electricity sector's ability to supply reliable service has come under increasing pressure. This is evidenced by more frequent gas supply constraints to generation plants, high levels of debt and increasing losses in the network. The key roots of the problems in the sector are the under-pricing of natural gas which fuels the majority of the power generation, and the low retail electricity tariffs which lead to high per capita consumption of electricity and thus large investment requirements in new generation capacity to keep up with the demand. The Government of Iran is aware of the challenges and is pursuing a number of reforms to improve the performance of the sector, including private sector participation in the generation of electricity and implementation of a power pool with a view of developing a competitive market. While these reforms will eventually contribute towards a more sustainable sector, their implementation and success will require tackling the under-pricing of natural gas and electricity. Without tackling these issues, the impact of reform efforts will remain limited and to some extent academic, and run the risk of increasing the Government's fiscal exposure as under-writer of the policies and transactions in the sector. This Note reviews some key challenges in the sector and highlights their strategic implications. The Note also provides some suggested next steps - in the form of a 'road-map' - to address the issues.

Demand for electricity

Consumption of electricity is high in Iran, as evidenced by per capita consumption of nearly 2,000 kWh per person (see figure 1) below. Demand has been growing at a steady rate of about 8% per year in the last few decades and the residential and industrial segments account for about a third each of the consumption. Demand is projected to continue at this rate in the foreseeable future.

Figure 1: Per capita power consumption in Iran vs other MNA countries



The high levels of consumption and the high annual consumption growth require substantial investment in new generation capacity and in the transmission and distribution networks to support service delivery. Indeed, over the period covered by the Fourth Five Year Development Plan (FYDP), a total of US$30 billion is required by the sector (see Table 1 below).

Table 1: Investment requirements (billion rials)

	2005	2006	2007	2008	2009	Total
Generation	17,325	24,169	28,611	29,176	26,367	125,648
Transmission	9,773	13,427	18,345	24,731	32,893	99,169
Distribution	7,108	8,464	10,102	12,052	14,413	52,139
Total	34,206	46,060	57,058	65,959	73,673	276,956

Source: Tavanir (2003-2004)

The majority of the consumption is concentrated along the main cities of Tehran, Esfahan and Ahwaz. The networks servicing these consumption centers have losses ranging from the average for Iran as a whole to quite severe, as is the case in Ahwaz (see table 2 below).

Table 2: T&D losses in Iran and three major provinces (%), 2004

	Transmission	Distribution
Iran	5.1	12.5
Tehran	3.9	11.5
Esfahan	2.4	14.3
Khuzestan (incl. Ahwaz)	6.0	34.2

Source: Tavanir; TREC

As a result of the high demand growth and the relatively high losses (average in the MENA region is about 15% and in the OECD countries it is about 6%), there are significant investment needs in the sector, averaging about US$6 billion per year, close to 4% of GDP[3]. This level of investments into the sector is very high by international standards and is primarily driven by the under-pricing of electricity which, in turn, results in excessive consumption by households and possibly keeps otherwise non-competitive industries operational. This implies that Iran could be over-investing in power system assets. This Note estimates that a reduction in demand from the projected 8.6% to 7% or 5.5% on average per year would generate savings in the order of 1.5% - 2.8% of GDP in avoided investments and avoided gas consumption, ranging from 0.12% of GDP at the current subsidized cost of natural gas to 3.4% of GDP at the assumed economic cost of natural gas[4]. Such a reduction in demand growth would require action on several fronts, including a reduction in the network losses and an aggressive demand-side management program targeting each consumer category.

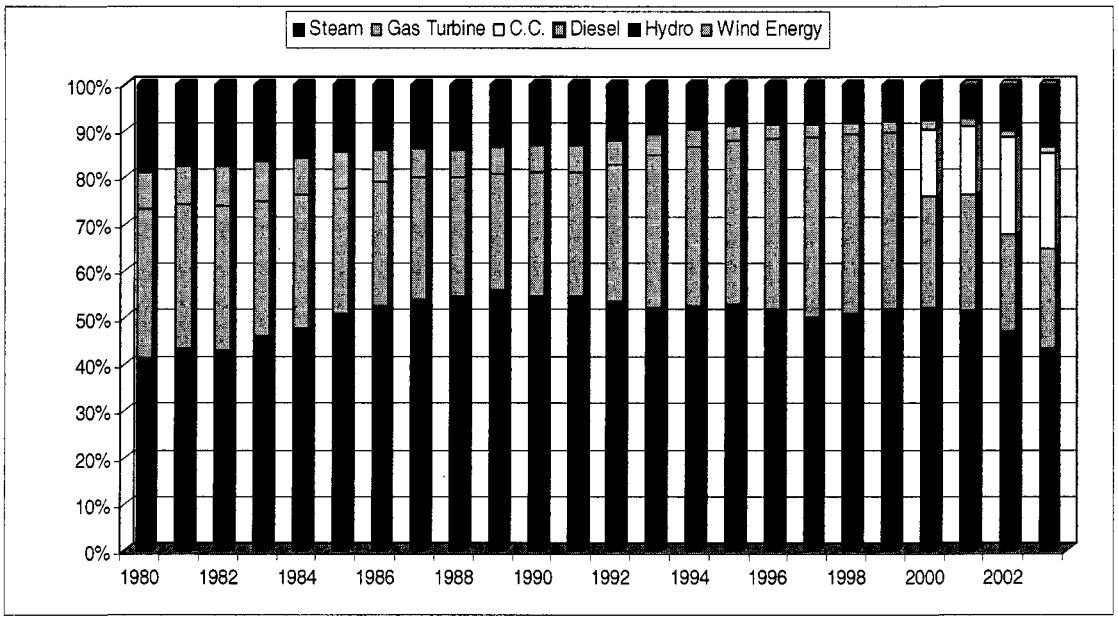
Electricity supply and the impact of subsidized natural gas

Installed capacity has essentially doubled in the past ten years, reaching 34 GW in 2003, while the reserve margin has deteriorated to about 19% (with significant seasonal variations reaching a low point below 10% in the summer). Deeper regional integration could be incorporated to manage geographical and seasonal electricity requirement and to enhance Iran's overall energy trading program.

[3] GDP in 2004/05 was US$158.6 billion (IMF Staff Report for the 2005 Article V Consultation).
[4] Economic cost assumed as 420 rials/m3 by Tavanir, or US$1.3/mmbtu.

The highly subsidized price for natural gas to the power sector (28 rials/m^3, US¢ 8/mmbtu) has resulted in a large share of steam-cycle and single-cycle gas turbines in the generation technology mix, with a slower incorporation of combined-cycle gas turbines and hydro-power technologies.

Figure 2: Technology Mix in Power Generation (1980-2002)



Source: Tavanir (2003-2004)

To assess the impact of natural gas prices on new generation capacity, this Note has estimated the marginal cost of electricity production based on variations in the natural gas price. Tables 3 and 4 illustrate that at - and beyond - US$1.3/mmbtu, CCGT and large hydro become the most economical technology options. The technologies would also have significant impact on emissions, in that CCGT has a much greater fuel efficiency than steam-cycle power plants and hydro-power would replace gas-fired power plants altogether. The low price charged for natural gas is widely debated in Iran and, as long as it remains as low as it is, it appears to slow down decisions regarding improvements to natural gas infrastructure and storage which, in turn, is required to eliminate the increasingly common natural gas supply shortages to the sector. The debate is also based on several views on the availability of gas in Iran (i.e., the reserves) and on a policy for its allocation.

Table 3: Levelized electricity generation costs US$/MWh)

	Small Gas Turbine	**Medium/Large Gas Turbine**	**Combined Cycle Gas Turbine**	**Steam Plant**	**Hydro (indicative)**	**Wind**
Capacity cost	5.30	7.62	7.42	11.22	14.68	52.53
Energy cost	2.45	2.77	2.30	3.32	2.70	9.27
Total cost	7.75	10.39	9.72	14.54	17.38	61.80

Assumptions: discount rate is 10%; natural gas price is US$0.08 per mmbtu. *Source: World Bank analysis, 2006*

Table 4: Sensitivity of levelized electricity generation costs to fuel prices (US$/MWh)

	Small Gas Turbine	Medium/Large Gas Turbine	Combined Cycle Gas Turbine	Steam Plant	Large hydro	Wind
Natural gas price = $0.77 per mmbtu	14.29	16.92	14.20	20.36	17.38	61.8
Natural gas price = $1.3 per mmbtu	18.86	21.50	17.34	24.44	17.38	61.8

Assumptions: discount rate is 10%. *Source: World Bank.*

Renewables and energy efficiency

In reviewing Iran's power supply options, it is important to consider its renewable resources. Indeed, Iran has substantial potential for the development of renewable energy, including wind, solar and hydropower. Significant research, development and pilot projects have also been implemented to demonstrate the technical feasibility of the resources. The key barrier to fulfilling the potential rests with the subsidies on conventional power production, notably the price for natural gas. These subsidies, in addition to the overall shorter lead-times for construction of thermal power plants, have hampered development of renewable projects. Today, many renewable projects remain stranded with incomplete financing plans after several years of preparation, feasibility testing and – in some cases – partial construction.

Likewise, in energy efficiency, Iran has introduced several measures to promote energy efficient consumption, including fuel switching, energy audits, development of standards, distribution of energy efficient light bulbs (CFLs) and introduction of mandatory energy performance labels for electrical appliances. Nevertheless, demand remains very high. This, as in the case with the relatively modest achievements on renewables, is largely due to the lack of economic cost recovery in pricing of electricity.

Other common barriers to wider scale development of renewables and energy efficiency include a somewhat fragmented institutional set-up, with several organizations involved in promoting renewables and energy efficiency, but lack of clarity on roles and responsibilities. This was however addressed in 2004 when the Ministry of Energy was appointed - legally - to handle renewable energy development. Under this arrangement, the Renewable Energy Department within the Ministry of Energy is responsible for renewable policy and planning while the Iran Renewable Energy Organization (SUNA) is responsible for the implementation of renewable projects. Furthermore, beyond the support for both renewables and energy efficiency in the Fourth FYDP in which feed-in tariffs to guarantee the purchase of renewable energy are supported, the existing legal and regulatory framework need to go further to adopt more specific measures and incentives to promote these two important elements of a more sustainable power sector. Therefore, Iran is encouraged to set targets for renewable energy, but it also needs to ensure that that the legal, commercial and regulatory frameworks be put in place to achieve the targets. This is particularly imperative in the case of hydro-power, where Iran possesses a strong capability for construction and management of hydro-power plants and where capital costs are close to those of thermal power plants when using economic natural gas price. Strategically, the modest achievements to date in both of these areas represent missed opportunities for Iran to save on costly thermal power generation.

Financial performance and cost of subsidies

The financial revenues and costs are consolidated at the level of Tavanir, the electricity holding company. Tavanir also plays a role in managing the sector's cash flow. Due to lack of cost recovery, Tavanir borrows funds from local banks to meet the cash flow requirements of the sector. These loans are guaranteed by the Government and are reported to eventually convert to grants. In 2003, the average price for electricity in the sector was 132 rials/kWh, while the average cost to supply electricity to end-users was estimated at 331 rials/kWh (see table 5 below).

Table 5: Electricity tariffs and subsidies in 2003 (rials/kWh)

Consumer category	Cost to supply	Price at which electricity was sold at	Subsidy	Subsidy as a % of set price
Residential	407	97	310	76%
Public	318	152	166	52%
Agriculture	323	14	309	96%
Industrial	289	163	126	44%
Commercial	396	412	-	-
Average	331[5]	132	200	60%

Source: Tavanir (2003-2004)

The tariff policy established under the Fourth FYDP states that electricity prices should remain constant during the first year (2004) and that any changes would require approval by the Parliament. Recently, tariff increases are reported to have been proposed for parliamentary approval.

This Note attempts to calculate the level of deficits in the sector by estimating the revenue deficit due to below-cost recovery tariffs. The analysis is not detailed but is intended to provide a sense of the magnitude of the subsidies, so as to facilitate the debate on this issue and on the overall need for price reform in the sector.

Based on the forecast of electricity consumption at 8.6% demand growth, the revenue deficit based on the pricing policy in the Fourth FYDP would amount to close to US$4.7 billion per year (see figure 3 below).

Figure 3: Electricity Subsidies

Electricity Subsidies

Source: Tavanir	Rials	US¢
Average tariff in 2003	132	1.7
Average cost of service supply in 2003	331	4.1

2,129,538 GWh
Over 10 years
≈ US$4.7 billion/year

A sensitivity analysis has been undertaken, to assess the impact on the deficit from variations in the natural gas price and the average cost of transmission and distribution in the sector. As figures 4 and 5 illustrate below, the revenue deficit would range from US$1.25 billion to US$4.1 billion (at 3.8 US¢/kWh).

Figures 4 & 5: Sensitivity Analysis

Cost of Supply @ 8 US¢/kWh

	3.3 - 3.8	2.3
Distribution (Int. benchmark)*	1.5 - 2.0	1
Transmission (Int. benchmark)	0.5	
Generation (marginal cost for medium-sized GT)	1.3	1.3

2,129,538 GWh Over 10 years ≈
US$4.1 billion/year @ 3.8 US¢/kWh
US$3.1 billion/year @ 3.3 US¢/ kWh
US$1.25 billion/year @ 2.3 US¢/kWh

Cost of Supply @ 1.3 US¢/mmbtu

	4.1 - 4.6	3.1
Distribution (Int. benchmark)*	1.5 - 2.0	1
Transmission (Int. benchmark)	0.5	
Generation (marginal cost for medium-sized GT)	2.1	2.1

2,129,538 GWh Over 10 years ≈
US$2.75 billion/year @ 3.1 US¢/kWh

* International Benchmark based on mature T&D system

US$4.1 billion represents close to 3% in 2004/05 GDP figures. It is important to note that this figure is based on the subsidized price of natural gas. Hence, it does not include the opportunity cost of the gas. This Note has estimated the opportunity cost of the gas (required to generate electricity to meet the demand projections at 8.6% annual demand growth) as being an additional US$4 billion/year.

Development of national electricity trading

The Government of Iran has established, as a policy objective, the creation of a competitive market for the supply of electricity. The purpose of this is to enhance efficiency and the reliability of supply. To implement this goal, important institutions have been established, including the Iran Grid Management Company (IGMC), which serves as both system operator and market manager, and the Electricity Market Regulatory Board (EMRB), which reviews and proposes prices in the sector and assesses options for further market and regulatory evolution. The market rules of 2005 allow for a fully-fledged competitive market to develop.

A truly competitive market will take some time to develop, given that certain pre-requisites for such a market are not yet in place. These include a reliable transmission network to serve as the backbone of the power system, i.e., the 400kV. Furthermore, international experience shows that markets do not work well when the competition is between subsidiaries of the same holding company, particularly when such companies have limited financial autonomy. The Government recognizes this, and is currently focused on putting in place a power pool, whereby dispatch of electricity is centralized - allowing for a merit order to be followed - and forcing the uniform set pool price towards the marginal cost of electricity supply. However, several important challenges will not be addressed by the power pool. For instance, given the low price for natural gas, there is no incentive for public or private market participants to construct CCGTs, given their relatively higher capital cost. Furthermore, the lack of fuel diversification and indeed fuel price competition limits the competition among generating units to O&M costs, which are likely to differ very little, given that the majority of generation assets comprise steam cycle and gas turbines.

Going forward, and with the immediate goal of making the power pool function, it will be important for the Government to focus on key steps, such as transferring high voltage assets to the IGMC to enable it to fully function as a market/system operator; improving information systems for dispatching and updating; and clarifying the role of the national grid. Improvement of the pricing methodology may also be necessary by, for example, the introduction of capacity payments so as to diversify the generation technologies used. Finally, and despite the role of Tavanir in the settlement process to ensure pool participants can recover cost, the introduction of the power pool is bringing benefits in that it forces transparency in the cost of electricity supply which, in turn, will facilitate the debate on price reform in the sector.

Involving the private sector

The Government is paving the way for private participation in the sector, initially in the generation segment. The objective is to increase efficiency and reliability of supply by involving the private sector. This will be achieved by reducing the debt burden of financing new power plants in the public sector and relying on the expertise and efficiency of the private sector in the construction, completion and operation of new and existing power plants. So far, the interest by the private sector has been driven by domestic investors, with some agreements (e.g., O&M) with foreign suppliers.

The involvement of the private sector is a good initiative, and starting with generation sub-sector makes sense, given the significant investment needs in this sub-sector and the ability to attract investors to it. Nonetheless, the Government of Iran needs to be aware of the risks. Firstly, while the financing of the power plants will be shifted off of the balance sheet of the public sector, the Government will be assuming significant contingent liabilities by guaranteeing the Energy Conversion Agreements (ECAs) being put in place. Indeed, this Note has estimated the annual obligation will amount to about US$1 billion, once several of the BOO and BOT projects are operational. Moreover, most of the new plants are based on single-cycle gas turbine technology and do not include any provisions or incentives for conversion to CCGT down the road. Having said that, the single-cycle gas turbines will allow for a retirement of the steam-cycles and, as such, they are a step in the right direction, as long as they can eventually be converted to CCGT. Also, the overall rate of return requirements of the private sector, which reportedly averages 20%-25%, reflects investors' perception of risk and will need to be compensated in the tariff agreed to under the ECAs. This risk, in addition to the fuel supply risk, is assumed by the Government and, needless to say, should there be fuel shortages and the private generation plants are inoperational for some period of time, the tariff will still need to be paid.

Therefore, the strategic implication of involving the private sector points to the need for the Government to monitor carefully its guarantees in the sector. Furthermore, this Note recommends that the Government review its overall generation strategy, in light of the plans to have greater private sector participation and move towards a more competitive market. Given the high demand growth, it is likely that there will always be elements of base-load demand which would warrant long-term contracts. The Government may, therefore, wish to consider liberalizing the market at the margin, starting, for example, with high voltage customers.

Legal and regulatory framework

The plans for reforming the power sector are comprehensive and include several elements of reform. However, the main legislation that governs the sector dates back to 1967 and is based on

a vertically integrated power sector with a monopoly on generation, transmission and distribution. This law has been at the center of debate and has been requested to be updated and proposed in the form of a new law to the Parliament. Nevertheless, the new law remains in draft form and has not been submitted for approval, likely due to further need to reach consensus on the future structure, ownership and regulation of the sector.

In contrast, significant progress has been made on passing a new investment law, the Foreign Investment Promotion and Protection Act (FIPPA). This act is of international best practice standard and covers all the key features an investment promotion act is expected to cover. However, notwithstanding the FIPPA legislation - and the openness of the Government to foreign investment – there is still a lack of significant foreign investment in the power sector.

This Note includes a review of the major legal frameworks that affect the power sector but concludes that the most important next step will be for the 1967 law to be revised and updated. This will force the Government to articulate its intentions with regard to ownership and industry structure, both of which are critical elements to a successful program of private power and achieving the envisaged efficiency gains of the power pool, and ultimately a competitive market.

Looking forward - Elements of a Road Map

The power sector in Iran has, in many ways, gone as far as it can in terms of implementation of its intended reforms. On the one hand, there are many advanced sector reforms being contemplated and initiated, including competition in the market and involvement by the private sector. On the other hand, several non-commercial practices remain (e.g., tariffs and subsidies) which are problematic in themselves and which will ultimately stand in the way for a more full-fledged implementation of the reforms. The scope of this Note is not to provide definitive recommendations to the Government of Iran on what to do next, nor how to do it. Rather, the scope of the Note is to highlight the strategic implications of some key aspects of the sector and to capture possible next steps in the form of a Road Map below. The Road Map is intended to guide the debate and to facilitate identifying the trade-offs in proceeding with the reforms of the sector, given that all worthwhile efforts come with a series of compromises and trade-offs.

The main challenges in the sector essentially come down to three: subsidy and tariff reform; planning for adequate generation; and ensuring reliable and efficient transmission and distribution of electricity supply. Depending on the desired scope and pace of reform, there are a number of steps in each of these areas that need to be taken. Some of these steps are summarized below.

Subsidy and Tariff Reform:

- The subsidy on natural gas causes significant distortions in the sector, as well as sub-optimal decision-making on technology. Therefore, to arrive at a more balanced energy resource development strategy in Iran where more efficient generation technology is implemented, the natural gas subsidy to the sector needs to be phased out.
- Eliminating the natural gas subsidy to the power sector will contribute to establishing the real cost of electricity supply. Cost recovery can then be introduced step by step, starting with the generation segment. This would improve the creditworthiness of the generating companies, allow for the power pool to function better without the interference of the holding company, and create a more level playing field for public and private power.

- Subsidy support can then be provided in the transmission and distribution sub-sectors, with the subsidy being gradually phased out, beginning in the transmission sub-sector.
- Work can then commence on achieving a more flexible retail tariff regime (e.g., removing the equalized retail tariffs), and targeted social support mechanisms for eligible consumers can be designed and implemented. This will help establish a more sustainable financial foundation for the sector and provide the necessary signals for more efficient energy usage.

Generation Planning:

- The objective is to achieve a more efficient generation mix, funded and implemented increasingly by the private sector, with fuel supply constraint bottlenecks removed.
- The phasing-out of natural gas subsidies would improve the generation mix, leading to the construction of more combined cycle gas turbine plants and competitive hydro-power plants. However, since the full elimination of gas subsidy will take some to achieve, the government policy should support construction of CCGT and economically feasible hydro projects.
- The increase in combined cycle facilities would enhance local manufacturing capacity of the technology, which would, over time, bring down the costs.
- Given the size of the market and the growth in demand, there is room for both public and private power, including long-term contracts as required by the private sector, but the Government should consider reducing its take or pay obligations on the margin, forcing private investors to also compete for market-share.
- The contracts with the private sector should build in flexibility and incentives to construct CCGT or enable conversion of single-cycle to CCGT. The key incentive in this regard is gas-pricing, which would be more effective than promoting CCGT through for example capital subsidies. Besides gas pricing, prospective investors could be given flexibility on when and how to apply the CCGT option through (a) investment decision (system expansion) where for CCGT results from "market-derived" (economic merit order dispatch) benefits that would accrue from low heat rate or; (b) investment decision (loss reduction) where for CCGT is selected as a means to accelerate the phase-out of existing low-efficiency "Steam Turbine Power Plants".
- Given the potential for less competitive renewable sources, such as wind, the Government could consider mandated market shares to promote their development which, in turn, will pave the way for price reductions on capital costs over time as well as develop technical know-how.

Efficient transmission and distribution of electricity supply:

- To achieve improved reliability, the power pool must dispatch electricity in the most economic way; the transmission and distribution networks must support the required levels of service provision and there must be no constraints preventing capacity-rich provinces from supplying capacity-poor provinces.
- For this to happen, the power pool needs to be further operationalized. This will require the transfer of the transmission assets to the IGMC; the design and implementation of new IT systems; and revisions to the technical and commercial market rules.
- The high voltage transmission network will need to be expanded and modernized to allow for unconstrained transfer of electricity, including loss reduction.
- The distribution network needs to be reinforced and rehabilitated for loss reduction, so that service provision to consumers is satisfactory and payment discipline can be maintained and further improved among government consumers.

- Once better cost recovery is achieved in the sector, the power pool can start evolving away from the single buyer model to a market with an increasing share of bilateral contracts. This can happen in phases, starting with high voltage consumers.

Chapter 1: Overview of demand for electricity and its characteristics

1.1 *Demand for electricity in Iran has been growing at a steady rate of 8% per year for the past few decades and is reported to be closer to 10% at present. Demand is driven by increased consumption among households as well as steady economic growth. Although increased demand for electricity often signifies a growing economy, it can also signify lack of energy efficient production and consumption patterns. In the case of Iran, the heavily subsidized retail electricity tariffs ranks Iran as one of the countries with the highest per capita power consumption in the Middle East and North Africa Region and is putting significant pressure on the system to supply electricity without interruption and forcing huge investments in new generation capacity every year. Indeed, this Note estimates that a reduction of a few percentages in demand provides savings potential in capital investments equivalent to 1.5%-2.8% of Gross Domestic Product (GDP) as well as fuel savings ranging from 1.85%-3.4% of GDP.*

Introduction:

1.2 Per capita electricity consumption is relatively high in Iran compared to the rest of the Middle East and North Africa (MNA) region, but relatively low compared to other industrial countries (see Figures 1 and 2).

Figure 1: Per capita power consumption in Iran vs other MNA countries

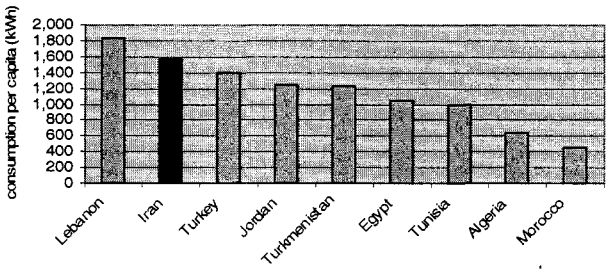
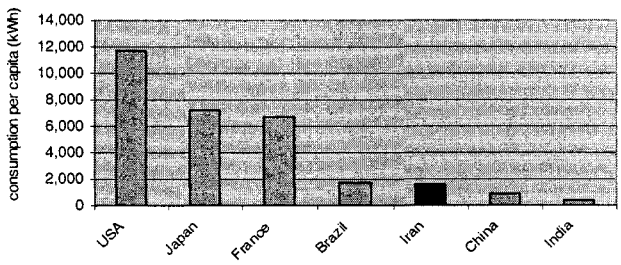


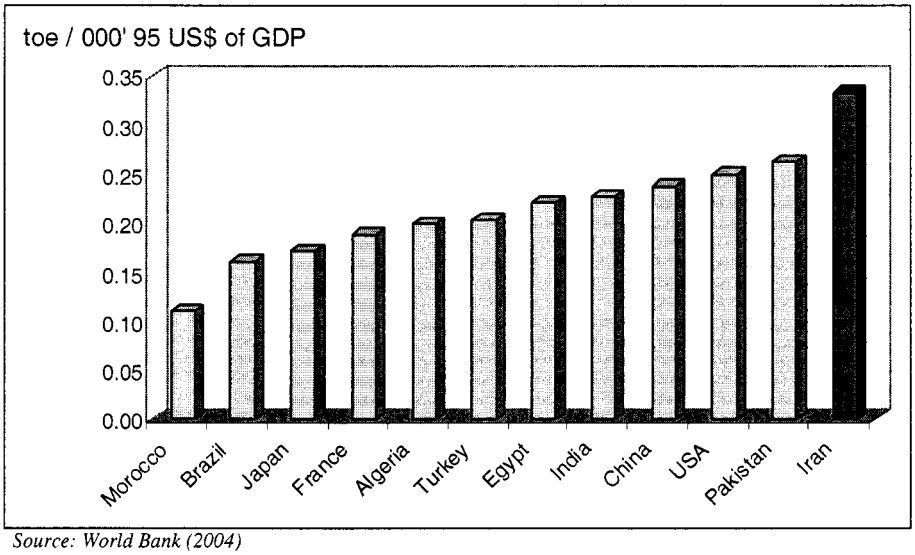
Figure 2: Per capita power consumption in Iran vs other industrial countries



1.3 Energy intensity on the other hand (as defined in relation to GDP), is higher in Iran than in most industrialized countries and also higher than more densely populated developing countries such as India or China[6] (see Figure 3). The Iranian energy consumption pattern resembles the structure of energy demand in industrialized countries in that it has relatively low non-commercial energy demand, a high share of building sector energy end-use (heating and appliances) and a high share of electricity consumption.

[6] World Energy Council (2001) Pricing Energy in Developing Countries. World Energy Council, London, UK.

Figure 3: Comparison of energy intensities between countries (2004)



Source: World Bank (2004)

1.4 Access to electricity is close to 100% in Iran and demand for electricity has been growing at an average rate close to 8% per year over the past few decades. Total electricity connections reached 18 million in 2003 and domestic consumption reached 114 TWh. In addition, there is demand for Iranian electricity in neighboring countries, through power interconnections with Azerbaijan, Turkey, Armenia, Turkmenistan, Pakistan and Afghanistan. Although quite small, Iran exported 919 GWh in 2003. Furthermore, imports were greater than exports in 2003 (see Annex 1 for a presentation of past consumption of electricity as well as the import and exports for the period covering 1992-2003).

Characteristics of demand for electricity:

1.5 Of the total final electricity consumption in 2003, residential and industrial consumers represented the largest shares (around one third each). Their share of the consumption has remained steady since 1995 (see Table 1.1). Agricultural and public electricity consumption amounted to around 12% each. Consumption data for the period 1995-2003 (Annex 1) shows that residential consumption grew at an average annual rate of 6.3%, industrial consumption at 7.1%, public consumption at 10.4% and agricultural consumption at 12.5%, while commercial consumption declined by 0.3%.

Table 1.1: Electricity consumption per consumer 1995 and 2003

	1995		2003	
	GWh	%	GWh	%
Residential	23,374	35.5	37,967	33.1
Public	6,203	9.4	13,714	12.0
Agricultural	5,402	8.2	13,859	12.1
Industrial	21,390	32.5	36,951	32.2
Commercial	7,655	11.6	7,461	6.5
Others	1,830	2.8	4,672	4.1

Source: Tavanir, (2003-2004)

1.6 At the same time, the load factor (i.e., the ratio of average demand to peak demand) has grown from 60% in 1995 to over 65% in 2003, indicating an increase in base and mid-load demand and thus

increased efficiency of the system. In terms of peak-load, the highest demand in Iran occurs in the summer months (May-August) and peak demand reached 27 GW in 2003.

1.7 Demand growth is driven by population growth and increase in income which has resulted in a larger use of electricity in consumer appliances. Iran's estimated GDP for 2004/05 was US$158.6 billion and real GDP growth has averaged around 6% for the past few years[7].

1.8 Energy intensive industry also accounts for a significant share of electricity consumption (see Table 1.2 for a list of the largest industrial consumers in the Tehran area as an example).

Table 1.2: Largest electricity sectors in Tehran province

Sector	MW
Automotive industries	138
Cement	57
Other manufacturing	31
Underground transport services	26
Oil pumping station	26
Services (radio and television broadcasting station)	10

Source: TREC, 2005.

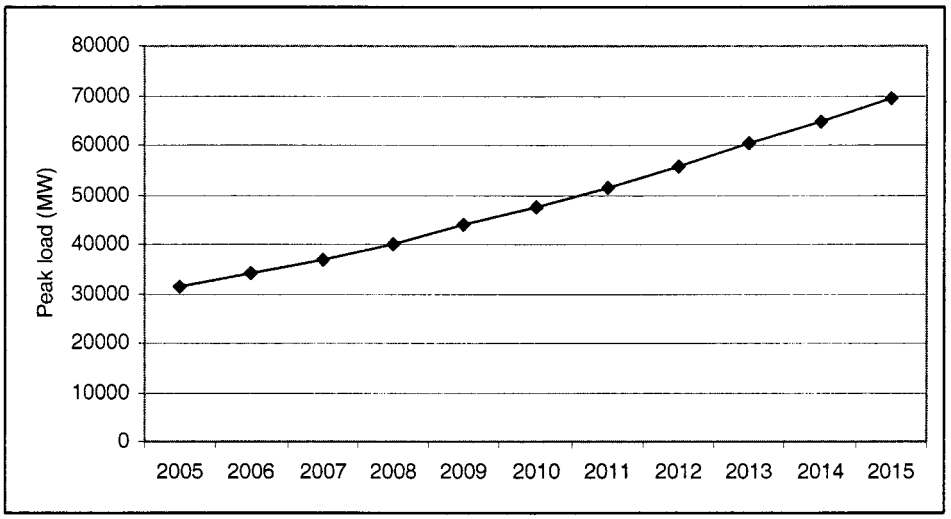
1.9 There are significant regional disparities in electricity consumption in Iran with the largest shares of consumption concentrated along the main cities of Tehran, Esfahan and Ahwaz. The single largest share of the consumption takes place in the Tehran province (21% of the total electricity consumption in 2004).

Future forecast of electricity demand:

1.10 According to forecasts prepared by Tavanir, the national power sector holding company, peak load is projected to grow at about 8.6% per annum over the 10 year period, 2005-2015 to reach 70 GW by 2015, or 400 TWh (see Figure 4 and Annex 2 for detailed forecast). This forecast takes into account continued efforts to reduce electricity price subsidies (see chapter 4) and continued improvements in income and GDP growth. Although the forecast considers a gradual reduction of price subsidies, this is expected to have little impact on demand given the prevailing very low tariffs.

[7] International Monetary Fund (IMF): Staff Report for the 2005 Article V Consultation.

Figure 4: Iran's peak load forecast 2005-2015



Source: Tavanir (2003-2004)

1.11 The continued growth in electricity demand challenges the Iranian power system's ability to meet demand. As a result, load-shedding (i.e., cutting off the electric current on certain lines when the demand becomes greater than the supply) still occurs in certain parts of the country (it was on average 1.7 minutes per day in 2003, compared to 3.9 in 1998)[8]. Furthermore, in 2002 and 2003 Iran was a net importer of electricity. Although imported electricity is small and some of it may make sense due to the interconnections with exporting countries near the load centers in Iran, it may reflect the difficulty of the sector to keep up with demand.

1.12 The quality of the transmission and distribution networks is also contributing to the reliability of supply problem. The system losses in 2003 (excluding auxiliary uses) comprised transmission losses (5.1%) and distribution losses (12.5%). Average losses in the Middle East and North Africa Region in transmission and distribution are about 15% and in OCED countries it is about 6%[9]. Yet, there are considerable variations between the 16 different electric power regions of Iran. Table 1.3 presents the losses in Iran on average and the three largest consumption centers, individually. Effort to reduce the losses is a key priority in the sector, but financial constraints pose a major challenge.

Table 1.3: T&D losses in Iran and three major provinces (%), 2004

	Transmission	Distribution
Iran	5.1	12.5
Tehran	3.9	11.5
Esfahan	2.4	14.3
Khuzestan (incl. Ahwaz)	6.0	34.2

Source: Tavanir; TREC

1.13 In 2003, the 400 kV lines totaled 11,361 km circuit, 230 kV lines were 22,419 km circuit , 132 kV lines 14,972 km and the 66 kV lines 32,776 km. In 2003, the 400 kV network represented 33.6% of the 400-230 kV network length, against 23.8% in 1978. Nevertheless, the length of high voltage network

[8] Tavanir, January 2006 World Bank Energy Mission.
[9] Based on Proceedings from Regional Roundtable on Water and Power in the Middle East, May 2004, Marrakech, Morocco, organized by the World Bank.

is still insufficient given the size of the country. Interconnection of networks is particularly important given the plan to develop a domestic electricity market (see chapter 4). A map of the transmission infrastructure is attached in Annex 3.

1.14 Investment in new generation to keep up with demand, in addition to the need for rehabilitation and extension of the transmission and distribution networks is substantial. Most of the investments have been undertaken by the public sector to date, but increasingly the private sector is starting to contribute to investment needs, particularly in generation of electricity. The investment plans include reinforcing the 400 kV network along the north south corridor between the cities of Ahwaz-Arak-Tehran and connecting the cities of Busher, Esfahan and Fasa along the southern coast to meet the growth of large industrial consumers and to reinforce the interconnection between the Khorassan province and the rest of the country (with Tehran in the north and with the central southern provinces of Yadz and Kerman). Table 1.4 presents the investment needs in the sector under the Fourth FYDP. As is shown in Table 1.4, a total of 276,956 billion rials (US$31 billion) is required during the period 2005-09.

Table 1.4: Investment requirements (billion rials)

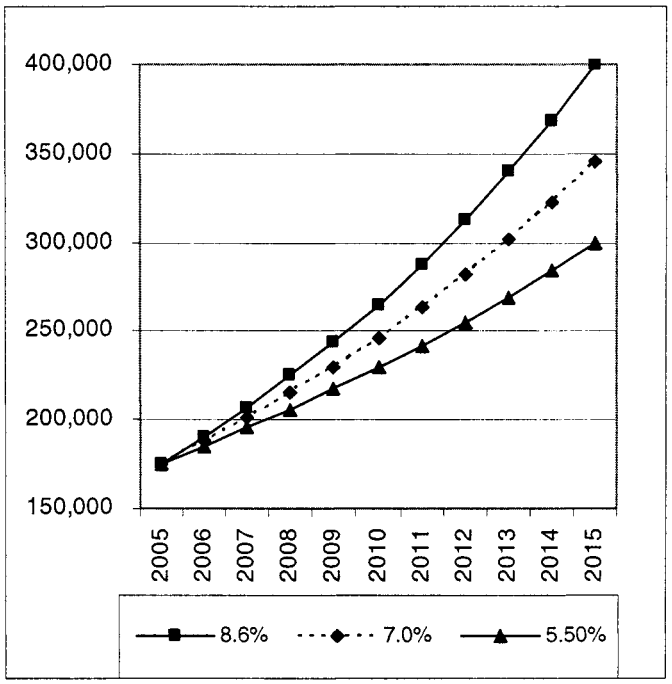
	2005	2006	2007	2008	2009	Total
Generation	17,325	24,169	28,611	29,176	26,367	125,648
Transmission	9,773	13,427	18,345	24,731	32,893	99,169
Distribution	7,108	8,464	10,102	12,052	14,413	52,139
Total	34,206	46,060	57,058	65,959	73,673	276,956

Source: Tavanir (2003-2004)

Impact on demand growth from increased elasticity of demand:

1.15 According to forecasts by Tavanir, Iran will need to add about 45 GW of generation capacity by 2015. As stated earlier, there has been little attention given to the elasticity of demand in Iran given the low retail prices and thus the limited incentive to reduce consumption as a result of price increases. However, given the impact of growing demand on investment requirements, there are potential savings in terms of avoided investments should demand be reduced. The calculations are based on analyzing alternative scenarios of electricity demand growth at annual rates that could possibly result from electricity price increase and slower economic growth than the base case calculated by Tavanir (i.e. average annual growth rate of 8.6%). Scenario 1 has an annual growth rate of 7.0%, still high by international standards, but lower than the growth rate observed in the decade 1995-2005. Scenario 2 has an annual growth rate of 5.5% which may result from a combination of higher electricity prices, more aggressive end-use efficiency measures as well as a slower economic growth. By 2015, total electricity consumption would be reduced by 14% in scenario 1 and 25% in scenario 2 compared to the base case. Over the period 2005-2015, a saving of 246 TWh would be achieved in scenario 1 and 457 TWh in scenario 2 (see Figure 5 below).

Figure 5: Electricity demand scenarios, 2005-2015.



Source: Tavanir; World Bank.

1.16 Lower electricity demand would in turn require reduced investments in new generation capacity. By 2015, capacity saved compared to the base case amount to 7.6 GW in scenario 1 and 13.9 GW in scenario 2. In addition, avoided new generation capacity would translate into fuel savings. Assuming all saved capacity is using natural gas, lower electricity demand translates into annual savings amounting to cumulative figures of 63 billion cubic meters (bcm) in scenario 1 and 117 bcm in scenario 2 over the period 2005-2015 (see Table 1.5 below and Annex 4 for details).

Table 1.5: Avoided generation capacity and fuel savings compared to base case.

	Scenario 1		Scenario 2	
	Capacity (MW)	**Natural gas (bcm)**	**Capacity (MW)**	**Natural gas (bcm)**
2005	-	-	-	-
2006	386	0.72	748	1.39
2007	833	1.55	1,602	2.98
2008	1,347	2.51	2,573	4.79
2009	1,936	3.61	3,673	6.84
2010	2,608	4.86	4,916	9.16
2011	3,374	6.29	6,317	11.77
2012	4,244	7.91	7,892	14.70
2013	5,230	9.74	9,660	17.99
2014	6,343	11.82	11,639	21.68
2015	7,599	14.15	13,852	25.80

Assumptions:
- All capacity saved is in the form of large gas turbines (159 MW boiler plate) operating at a plant factor of 83%.
- Natural gas savings calculated using an average (de-rated) heat rate of 9150 Btu per kWh.

Source: World Bank.

1.17 Using capital cost figures of US$296 per kW[10] installed of additional electricity generation, the lower electricity demand scenarios translate in total capital investments savings equivalent to 1.5% of GDP in scenario 1 and 2.8% of GDP in scenario 2 (see Table 1.6 below). Additional savings are achieved through lower natural gas consumption for electricity production. At the current price of gas of 28 rials/m^3, the lower electricity consumption translates into a direct financial fuel saving over 2005-2015 amounting to 0.12% of GDP in scenario 1 and 0.23% of GDP in scenario 2. At 420 rials/m^3, the fuel savings reach 1.85% of GDP in scenario 1 and 3.43% of GDP in scenario 2.

Table 1.6: Avoided generation capacity investments and gas consumption from lower electricity demand compared to base case.

		Scenario 1	**Scenario 2**
Electricity demand (expressed as generation growth)	%	7.0%	5.5%
2015 avoided generation	%	-14%	-25%
2015 avoided electricity generation capacity	MW	7,599	13,852
2015 avoided capacity generation investment*	billion US$	2.25	4.11
2015 avoided capacity generation investment*	% of GDP**	1.55%	2.83%
Total avoided gas consumption, @ gas price of Rials 28 per m^3	% of GDP**	0.12%	0.23%
Total avoided gas consumption, @ gas price of Rials 260 per m^3	% of GDP**	1.14%	2.12%
Total avoided gas consumption, @ gas price of Rials 420 per m^3	% of GDP**	1.85%	3.43%

*assuming all capacity saved is in the form of new gas turbines to be installed (figures in year 2004 US$)

**GDP figures used in the calculation are in year 2004 US$

Capital cost of $296 per kW installed

Gas savings are calculated in 2004$, using a 10% discount rate

Source: World Bank.

[10] Average cost for medium size single cycle gas turbines in Egypt.

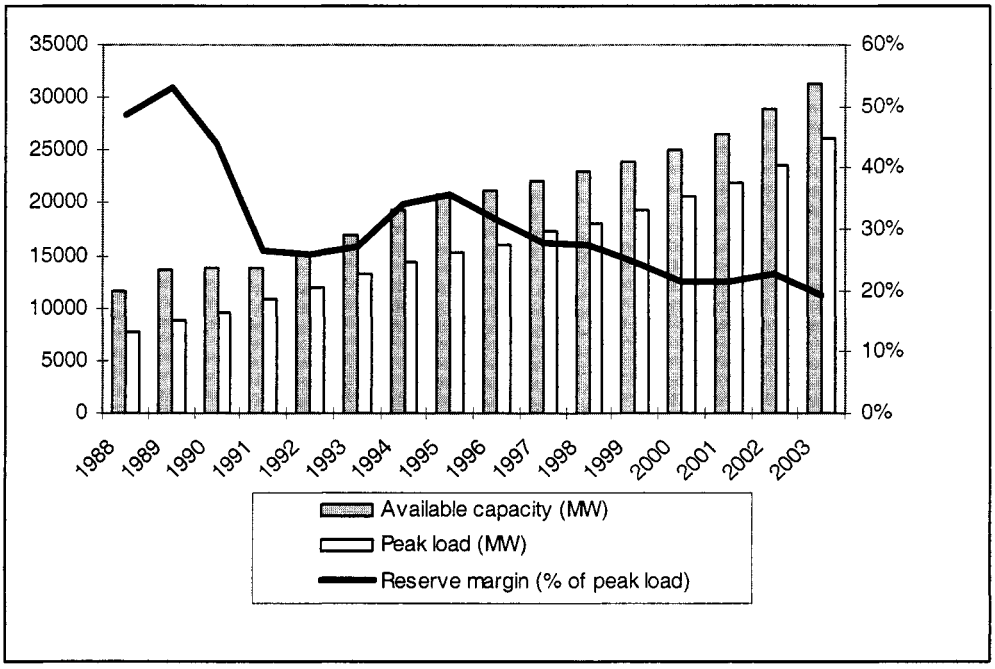
Chapter 2: Overview of electricity supply and the impact of subsidized natural gas

2.1 *Most of Iran's electricity is generated by thermal power plants using natural gas as the main fuel. The price for natural gas to the power sector is remarkably low at 8 US¢/mmbtu – as a comparison, gas to Europe on pipelines or as Liquefied Natural gas (LNG) on long term contracts sells for $4-5/mmbtu*[11]*. The natural gas subsidy impacts generation planning and decision-making and is a key reason for the wide use of single-cycle gas turbines, the deferred retirement of steam-cycle plants and the under-development of renewables, notably hydro-power. Furthermore, the subsidies are slowing down government decision-making on the allocation of natural gas to different sectors, including the power sector, resulting in gas shortages at times and the need to use fuel oil which could otherwise be exported.*

Introduction:

2.2 Iran's installed capacity was 34 GW in 2003 and production reached 149 TWh[12]. As shown in Figure 6, nominal electricity production capacity doubled between 1992 and 2003 and during the same period the average annual reserve margin deteriorated to about 19% in 2003. Demand for electricity varies greatly during the year in Iran and so does the reserve margin, reaching – in 2003 - a maximum of 30.5% in January-February and a minimum in June-July of 8.8%.

Figure 6: Electricity generation capacity (1988-2003)



Source: Compiled from various report and documents from Tavanir.

Iran's gas:

[11] In addition, the average 2006 price for natural gas at the Henry Hub Spot Market was US$8/mmbtu.
[12] Tavanir Report: "Electric Power in Iran", 2003-2004.

2.3 With 971 Tcf of proven reserves[13], Iran has the world's second largest gas reserves (see Table 2.1 below). About 10 percent of Iran's gas reserves are in the South Pars gas field, the largest gas field in the world. Other major gas fields in Iran include North Pars, Kangan, Nar and Khangiran. The current reserves to production (R/P) ratio is over 100 years and the share of Iran's proven gas reserves is 15 percent of total proven world gas reserves[14].

Table2.1: Proven Gas Reserves, 2004

	Tcf	Share of Total (%)	R/P Ratio
Russian Federation	1694	26.7	82
Iran	**970**	**15.3**	**over 100**
Qatar	910	14.4	over 100
Saudi Arabia	238	3.8	over 100
United Arab Emirates	214	3.4	over 100
Total North America	258	4.1	10
Total South & Central America	250	4	55
Total Africa	497	7.8	97
Total Asia Pacific	501	7.9	44
Total World	6337	100	67

Source: BP Statistical Review of World Energy, June 2005

2.4 Iran currently produces 85 Bcm of natural gas annually or 3.2 percent of total world production (see Table 2.2 below). Considering its large reserves, there is enormous potential to increase production in the near future. But Iran faces challenges to capitalize on its reserves. Lack of investment in pipeline infrastructure and storage has forced the power sector to rely on fuel oil for power production during the winter months in recent years when residential demand for gas is high. For example, in 2003, the steam power plants consumed about 6 Mtoe of fuel oil, representing an economic cost of close to US$1 billion[15] and Iran imports natural gas from Turkmenistan to supply fuel to power plants in the north-eastern part of the country. As in the case of electricity imports, importing gas is logistically useful given that Iran's gas reserves are concentrated in the south and the imported gas is coming in from the north. Nevertheless, given the deteriorating capacity reserves margin in Iran, additional pressure on security of supply due to possible gas import (or electricity) interruptions would have significant negative impact on supply availability in Iran.

Table 2.2: Gas Production, 2004

	Bcm	Share of Total (%)
Russian Federation	589	21.9
Iran	**86**	**3.2**
Qatar	39	1.5
Saudi Arabia	64	2.4
United Arab Emirates	46	1.7
Total North America	763	28.3
Total South & Central America	129	4.8
Total Africa	145	5.4
Total Asia Pacific	323	12
Total World	2692	100

Source: BP Statistical Review of World Energy, June 2005

[13] BP Statistical Review of World Energy, June 2005.
[14] BP Statistical Review of World Energy, June 2005
[15] Assuming a calorific value of 42 GJ/t and a price of US$154.5/ton based on average 2003 Mideast Gulf price of high sulfur oil (3.5% sulfur (source: Energy Intelligence).

2.5 The under-investment in the gas infrastructure may also be closely linked to US sanctions[16], which keeps US companies out of Iran and also serve as a disincentive to other countries' firms and multinationals because of the threat of secondary sanctions. US policy also discourages the import of Iranian gas and as such the opportunity cost of using gas domestically is reduced. Nevertheless, the continued heavily subsidized natural gas prices to the sector hinders investment and slows down decision-making as to allocation of natural gas given the opportunity costs involved in supply to the power sector. At the same time, the domestic demand for oil products has increased and oil exports have gradually declined. Today, Iran, despite having a major share of the world's oil reserves, has become a net importer of petroleum products. For the financial year that ended in March 2006, Iran is reported to have imported petroleum products worth US$4.5 billion (close to 3% of GDP using the 2004/05 figure of US$158.6 billion). There could be reasons of economic geography behind the import of petroleum products, but import requirements are also reported to be closely linked to lack of investment in refining capacity and the rapidly growing demand due to low retail prices.

2.6 Today, most of Iran's gas is consumed domestically. However, an operational gas pipeline exists with Turkey for exports (see Table 2.3 below) and with Turkmenistan for imports. Iran imported 5.2 Bcm of natural gas from Turkmenistan in 2004 and an accord recently signed between Iran and Turkmenistan will see Turkmenistan increase its natural gas exports to Iran to 14 Bcm/year by 2007. Iran pays a competitive price for the gas which is reported to be about $65/Mcm (or US$2.3/mmbtu)[17]. As a comparison, the economic cost of domestic gas is estimated at US$1.3/mmbtu (see more below in paragraphs 2.13-2.17) and gas to Europe on pipelines or as LNG on long term contracts sells for $4-5/mmbtu.

Table 2.3: Exports to Turkey in million cubic meters

Year	To Turkey
2001	115
2002	670
2003	3520
2004	3550
2005	4322

Source: Botas website, 2006

2.7 Besides Turkey, potential piped gas markets for Iranian gas include Europe, South Asia (India, Pakistan) and the south Caucasus (Armenia, Azerbaijan, Georgia). LNG export markets include Taiwan, South Korea, Japan and China. British Gas and the National Iranian Oil Company are developing a $2.2 billion LNG plant at Bandar Tombak on the Persian Gulf coast. The plant is to comprise two LNG trains, with capacity of at least 4 million tons per year each. This plant is planned for completion in 2008.

Natural gas in the power sector:

2.8 To increase oil exports, the Government has been implementing a fuel switching strategy to increase the use of natural gas in the power sector - a cleaner fuel with a lower economic value than oil - and to pursue non-fossil fuel technologies such as hydro and renewables. Today, most of the electricity generation is based on natural gas and the share of oil (heavy fuel oil and to a lesser extent, diesel) has

[16] 1995 Executive Orders (extended by President Bush in March 2004) prohibiting US companies and their foreign subsidies from conducting business in Iran and the US Iran-Libya-Sanctions Act (ILSA) of 1996 (renewed for 5 more years in 2001) imposes mandatory and discretionary sanctions on non-US companies investing more than US$20 million in the Iranian oil and natural gas sectors. Sanctions on Libya were recently lifted.
[17] "Gas Matters", April 2006

fallen to 18% (see Table 2.4 below on the fuel mix in Iran and a few other countries with significant hydrocarbon resources). As is illustrated in the table, additional scope remains to reduce further the use of oil products in Iran.

Table 2.4: Fuel mix in different countries, 2002 (GWh)

	Oil products	Natural gas	Hydro
Iran	18%	76%	6%
Algeria	2.2%	97.6%	0.2%
Egypt	7.5%	76.0%	16.5%

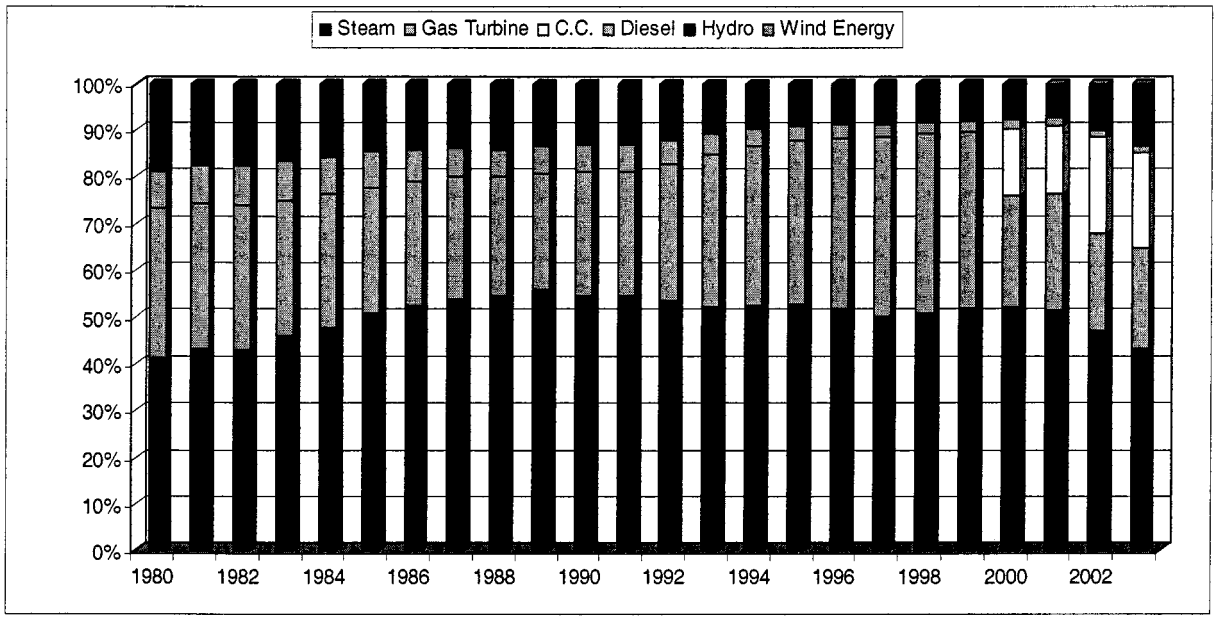
Source: IEA, Energy Balances of Non-OECD Countries, 2005.

2.9 Further to the information in Table 8, in Egypt, the increase of natural gas usage continues in line with the large capacity of combined cycle plants being added. By 2003, the natural gas share had increased to 79% and about 1% wind had also been added.

Generation technology mix to supply electricity:

2.10 Power is mainly produced from thermal and some hydro plants in Iran. More specifically, steam boiler plants have been used for a long time in Iran and still have a dominant position when it comes to share of power plant technology used. In addition single-cycle gas turbines also play a significant role. However, their share is reducing in favor of combined-cycle gas turbines with higher fuel efficiency (see Figure 7 below). Indeed, the Bank financed such a conversion in the mid-1990s when 6 128 MW gas turbines at the Ghom Power Plant were converted to combined cycle, adding 200 MW of capacity[18]. As can be seen, hydro plays a role, but wider deployment is hampered by the low cost of natural gas to the power sector and hydro projects' relatively longer construction lead times (see more in Chapter 3).

Figure 7: Technology Mix in Power Generation (1980-2002)



[18] Power Sector Efficiency Improvement Project, approved on March 30, 1993.

Source: Tavanir (2003-2004)

2.11 In 2003 single-cycle gas turbines accounted for 21% of installed capacity and produced 12% of total electricity. These plants have the advantages of low initial capital costs and short construction periods but they also have low generating efficiency and thus high running costs (fuel efficiency of single-cycle gas turbines was 28%, compared to 44% for combined cycle gas turbines and 38% for steam cycle plants in 2003). The use of this technology choice has been largely driven by the need to construct power plants quickly and the low cost of natural gas to the sector. However, the inefficient use of natural gas by these plants has further aggravated the problem of gas shortages during the winter months. In OECD countries, single-cycle gas turbines are typically used to meet peak load demand and as such account for much smaller shares of capacity and electricity generation, whereas in Iran they have been used to meet both base and peak demand at times.

2.12 The Government recognizes the inefficiency of using single-cycle gas turbines as much as it does and for other purposes than to meet peak-load. The plan is therefore to convert these plants to combined cycle to reach higher efficiency. Yet, the low price of natural gas charged to the electricity sector clearly affects the speed at which these conversions take place and the ability of the Government to make optimal investment decisions regarding generation projects, taking into account an economic value of the natural gas resources. As a result, the share of combined cycle gas turbines power plants had only reached 20% of total nominal capacity by 2003 (see Table 2.5 below). Furthermore, Iran's potential for renewable energy from sources such as hydro, wind and solar remains under-developed (see Chapter 3).

Table 2.5: Gas turbines and combined cycle power plants (% of total nominal capacity), 1991-2003

	Gas Turbine	Combined Cycle
1991	27%	-
1994	34%	-
1997	38%	-
2000	12%	19%
2003	22%	20%

Source: Tavanir, 2003-2004

2.13 To assess the impact on technology choice from changes in natural gas prices an analysis was carried out to calculate the levelized cost of electricity production in Iran. Using a 10% discount rate and a gas price of 28 rials/m^3 (8 US¢/mmbtu) the levelized cost of electricity production from gas production in Iran ranges from around $7.75 to $14.54 per MWh (see Table 2.6 below).

Table 2.6: Levelized electricity generation costs US$/MWh)

	Small Gas Turbine	Medium/Large Gas Turbine	Combined Cycle Gas Turbine	Steam Plant	Hydro (indicative)	Wind
Capacity cost	5.30	7.62	7.42	11.22	14.68	52.53
Energy cost	2.45	2.77	2.30	3.32	2.70	9.27
Total cost	7.75	10.39	9.72	14.54	17.38	61.80

Assumptions:
- discount rate is 10%.
- natural gas price is $0.08 per mmbtu
(See annex 4 for details)

Source: World Bank analysis, 2006

2.14 Looking forward, towards the ambitions to develop a market, the low price of gas reduces the energy component of electricity prices but ends up playing against technologies with relatively higher levels of payment required to cover the capacity component of electricity prices due to their higher capital costs. Fuel price distortions therefore have a significant impact on investment decisions. Similarly, low gas prices reduce the incentive to retire older and less efficient steam plants and undermine the opportunities to develop the hydroelectricity potential of the country more extensively.

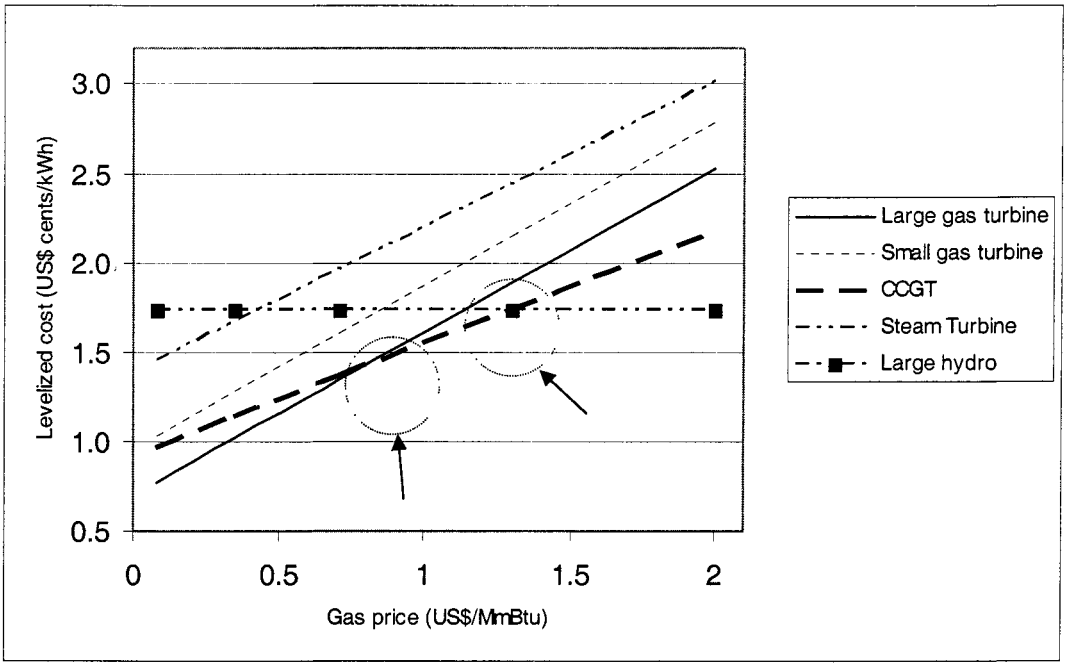
2.15 Changes in the fuel price would alter the relative electricity costs of different types of plants. Indeed, at a gas price of US¢ 77/mmbtu (compared to the actual price of US¢ 8/mmbtu), CCGT claims the first position in the merit order based on capacity + energy costs. Beyond US$1.3/mmbtu for natural gas (or 420 rials/m^3), hydro technology costs becomes lower than CCGT.[19] See Table 2.7 and Figure 8, as well as Annex 5 for details. Also see Chapter 3 for more analysis on hydro-power in Iran.

Table 2.7: Sensitivity of levelized electricity generation costs to fuel prices (US$/MWh)

	Small Gas Turbine	Medium/Large Gas Turbine	Combined Cycle Gas Turbine	Steam Plant	Large hydro	Wind
Natural gas price = $0.77 per mmbtu	14.29	16.92	14.20	20.36	17.38	61.8
Natural gas price = $1.3 per mmbtu	18.86	21.50	17.34	24.44	17.38	61.8

Assumptions: discount rate is 10%.
Source: World Bank.

Figure 8: Sensitive of Electricity Generating Costs to Natural Gas Price



Source: World Bank analysis, 2006

[19] US$1.3/mmbtu (420 rials/m^3) is the value used by Tavanir as a reference for electricity planning purposes.

2.16 Reducing the subsidy on natural gas prices would also allow existing CCGT to be operated for longer periods of time. Assuming a system using only single cycle gas turbines and CCGTs, the number of hours during which single cycle gas turbines would be used for peak purposes at different prices of gas can be calculated.

2.17 Comparing the current subsidized gas price to the power sector (US$0.086/mmbtu) with the economic price used by Tavanir (US$1.3/mmbtu), shows – in Table 2.8 - that, when an economic value is used, it is economic to run combined cycle gas turbines longer than single cycle turbines and there would be a reduction in the time when single cycle gas turbines are dispatched for peak purposes from 312 hours (4% of the time) to 41 hours (0.5% of the time).

Table 2.8: Sensitivity of optimal running time for large gas turbines and CCGT

Gas price = 28 rials/ cubic meter (US$0.086/mmbtu)

		Large gas turbines	CCGT	Share of time
Total fixed cost	$/kW/year	45	62	
Total variable cost	$/kWh	0.15	0.10	
Peak operating time	Hours	312	-	3.6%
Off-peak time	hours	-	8448	96.4%

Gas price 420 rials/ cubic meter (US$1.3/mmbtu)

		Large gas turbines	CCGT	Share of time
Total fixed cost	$/kW/year	45	62	
Total variable cost	$/kWh	1.26	0.86	
Peak operating time	hours	41	-	0.5%
Off-peak time	hours	-	8719	99.5%

Source: World Bank analysis, 2006

Box 2.1: The capital costs of grid-connected electricity generating technologies compare favorably to the rest of the world.

Substantial engineering and domestic assembly capacities have been developed in Iran and are contributing to the relatively low cost of new power plants in Iran. This result is particularly clear in the case of capital costs for medium or large gas turbines (single and combined cycles), which range from US$296 to 497 per kW, considerably lower than equivalent figures found in OECD countries).

Although fuel represents the bulk of electricity production cost, low capital costs, along with low operation and maintenance costs (other than fuel) contribute to the low levelized costs of electricity discussed in this Note.

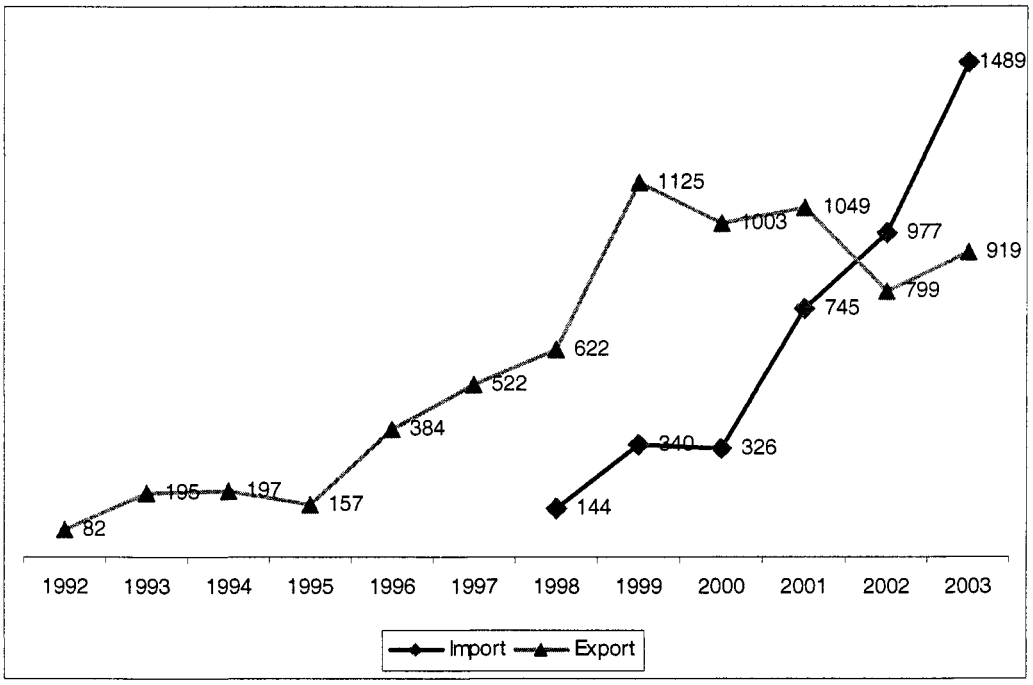
	Domestic	Foreign	Total	OECD equivalents
Small Gas Turbine	66	295	361	-
Medium/Large Gas Turbine	108	188	296	400-500
Steam Plant	174	455	629	550-800
Combined Cycle gas turbines	25	472	497	600
Hydro (indicative as costs are site specific)	600	-	600	1000-3000
Wind	1,000	-	1,000	1000-2000

Source: Tavanir; World Bank, Technical and economic assessment: off-grid, mini-grid and grid electrification technologies, Discussion Paper, Nov. 2005; International Energy Agency, Projected costs of generating electricity, 2005.

Regional Integration:

2.18 Iran also meets its power supply needs by trading with neighboring countries and there is potential for expanding interconnections (see Figure 9 and Table 2.9). Although Iran has huge primary energy resources, they are mostly located in the south and south eastern part of the country whereas some of the large load centers are located in the northern half of the country, in the northwestern province of Azerbaijan bordering the Republic of Azerbaijan, Armenia and Turkey, and in the eastern province of Khorassan. Trade with adjoining electricity systems would therefore be developed to even out energy shortages on both sides of the borders. It is important to note that the interconnection between Iran and Turkmnistan is based on a tri-lateral agreement for energy transit from Turkmenistan to Turkey via Iran's network. The potential for electricity trade development needs careful review to exploit potential economic opportunities.

Figure 9: Electricity imports and exports (Gwh)



Source: Tavanir (2003-2004)

Table 12: Exchange of electric energy between Iran and the neighboring countries, 2003

Country	Import to Iran Gwh	Voltage kV	Capacity MW	Exports from Iran Gwh	Voltage kV	Capacity MW
Pakistan	-	-	-	47	132	18
Afghanistan	-	-	-	17	20	2.7
Turkmenistan	584	230	379	1	230	12
Azerbaijan	582	230	210	569	132, 2x20	97
Armenia	323	230	187	159	230	208
Turkey	-	-	-	126	132	89
Iraq	-	-	-	-	230	80

Source: Tavanir (2003-2004)

2.19 Recent discussions between Iran and its neighboring countries, indicate that exports to Pakistan are likely to increase. At about US¢ 6/kWh, Pakistan views imports from Iran as attractive compared to self-generation. Iraq is also keen on increased imports as is Afghanistan. In the case of Afganistan, Iran provides aid through electricity supply and sells electricity at a subsidized rate of about US¢ 2/kWh.

Chapter 3: Renewable energy potential and energy efficiency opportunities

3.1 *Iran has devoted significant time and effort into the research and development of renewable energy technologies and enhancement of efficiency in the energy consuming sectors. Nevertheless, exploitation of both to enhance energy supply remains far from optimal largely due to the need for short construction periods of new power plants to meet demand and the relatively higher cost of renewables given the subsidies on natural gas, as the previous Chapter illustrated. Experience from around the world points to important policy instruments to encourage development of renewables even when there is a cost disadvantage. Likewise, energy efficiency, particularly related to demand side management measures, face challenges when prices are too low to establish incentive. Under such circumstances, measures aimed at reducing the demand at peak periods and thus relieving the pressure of maintaining investment to meet peak demand is critical. This Chapter documents experiences from within and outside Iran and provides suggestions for further action.*

Introduction:

3.2 When reviewing supply options for power generation in Iran it is important to consider Iran's potential for renewable energy. At present, development of renewable energy remains limited however, as it does in many countries with an abundance of fossil fuel resources. Nevertheless, the Government realizes that renewable energy sources could take up a significant share of the energy supply options if they were properly developed and has therefore made it a priority in order to diversify the power generation mix.

3.3 Several institutions are involved in the promotion of renewable energy in Iran. The most significant of them is the Iran Renewable Energy Organization (SUNA) which in 2004 assumed the staff and facilities of the Center for Renewable Energy Research and Applications (CRERA) when the latter ceased in existence.

3.4 SUNA was created in 1995 under the Ministry of Energy, in order to assume the responsibility of developing renewable energy in Iran, through the implementation of research projects, studies, awareness raising and pilot plants. In 2000, SUNA was changed into a state-owned organization and has independently of the Ministry of Energy assumed the responsibility of several renewable energy projects since 2003.

3.5 CRERA was created in 1992 with the objective of conducting research and studies in the field of renewable energy technologies. Since its creation, CRERA has been active in the solar, wind, biogas and geothermal energy domains. In the field of solar and wind energy in particular, CRERA has been responsible for the purchase and installation of more than 11 MW of wind and solar power plants.[20]. CRERA staff and facilities were transferred to SUNA in 2004. The capacity of Manjil and Roodbar wind sites were recently increased to 34 MW.

[20] Data based on the following:
(1) CRED webpage on the Atomic Organization of Iran's website at http://www.aeoi.org.ir/NewWeb/Research/Cred/CRED.htm (March 7, 2006).
(2) Hazemi Karegar, H. et al. (2002) *Wind and Solar Energy Developments in Iran*. Paper presented at the 2002 Australian Universities Power Engineering Conference, Melbourne, 29 September – 2 October, 2002.

3.6 Development of the renewable energy sources has focused on hydro, wind and solar, however, Iran also has potential in developing geothermal and biomass. The section below presents the potential for hydro, wind and solar along with current activities being pursued in Iran. Barriers to development of renewable energy are also discussed along with ideas for removing barriers and enhancing renewables' potential.

3.7 *Hydropower*: Most of Iran's hydroelectric plants are located in the Western and Southwestern provinces along the Karoon and Dez rivers. The development of future hydropower plants is planned for the Northern and Northwestern parts of Iran.[21] Today's hydropower plants are mainly large reservoir hydroelectric plants. The lower share of output relative to the share of installed hydroelectric capacity reflects a relatively low plant factor of hydroelectricity due to the multi-purpose use of the dams, including large use by the agricultural sector.

3.8 Iran has large potential for hydroelectric power production. The total potential for hydropower has been estimated at about 50 billion kWh/year.[22] In 2003 installed hydro capacity contributed to 11 GWh of power production (7.5% of the total power produced). 243 hydropower plants are under study, construction and operation in Iran. In fact, the Government targets an expansion of hydropower to 19% of the electricity produced by 2010 (about 6,800 MW additional capacity).[23]

3.9 However, increasing the share of hydro power in Iran faces several challenges including their longer construction time, need for significant upfront investment and, under current natural gas and electricity pricing policies, being relatively more expensive. This situation has left the hydro capacity expansion plans somewhat stranded and some hydro construction projects unfinished.

3.10 *Wind*: The potential for wind energy in Iran has been estimated based on data from 26 meteorological sites throughout the country, and analyzed by CRERA and the Ministry of Energy. The potential amounts to about 6,500 MW. Iran's first experience with installation and operation of modern wind turbines dates back to 1994, when two sets of 500 kW wind turbines were installed in Manjil and Roodbar. After this successful experience, contracts for 27 wind turbines (totaling 10.5 MW of installed capacity) were signed in 1996 and installed by 1999 in Manjil, Roodbar and Harzevil (also located near Manjil).[24] As of 2004, the Manjil-Roodbar windfarm had been equipped with 39 wind turbines and an overall capacity of 15.7 MW, while in the Harzevil location there were three units and a total capacity of 900 kW. In aggregate, the wind farms produced about 30GWh in 2004, representing a share of 0.02% of the total power produced that year.[25] In addition, future projects amounting to 130 MW of wind power plants are underway. These include wind power projects in Binalud and Dizbad (Khorasan province) for a total capacity of 28.9 MW).

3.11 *Solar*: Solar radiation in Iran varies between 2.8 kWh/m^2 in the South East and 5.4 kWh/m^2 in the central region, with an average of more than 2,800 hours of useful solar radiation per year. Several small-scale solar projects were started between 1993 and 1998 in order to test the exploitation of Iran's solar potential, and have resulted in the installation of about 112 kW of solar capacity (photovoltaics and

[21] Data extracted from the "Introduction to Rudbar Lorestan Dam and HPP Project", document provided by the Iran Water and Power Resources development Company during the World Bank power sector mission in January 2006.
[22] Data extracted from the "Introduction to Rudbar Lorestan Dam and HPP Project", document provided by the Iran Water and Power Resources development Company during the World Bank power sector mission in January 2006.
[23] Tavanir (2004) Electric Power Industry in Iran
[24] Hazemi Karegar, H. et al. (2002) Wind and Solar Energy Developments in Iran. Paper presented at the 2002 Australian Universities Power Engineering Conference, Melbourne, 29 September – 2 October, 2002.
[25] Tavanir (2004) Electric Power Industry in Iran. Tavanir specialized holding company, Tehran.

solar pumps).[26] Iran is also developing capacity for solar-thermal plants with a 250 kW plant in Shiraz for which parts of the civil works, including landscaping, buildings and relevant accessories, as well as purchasing the mechanical equipment, have been completed. As of 2004, the collector farm was at a testing and commissioning stage and installation of the mechanical equipment and steam-generation section are expected to start shortly.

3.12 It is worth mentioning that a survey has been carried out that estimates Iran's biomass potential to be about 806 MJ.

Barriers to renewable energy development:

3.13 While renewable energy has significant potential in Iran, this potential is not being fully realized due to various barriers which prevent larger scale investment and development to take place. These barriers put renewable energy at a disadvantage relative to conventional forms of energy supply. The barriers include the subsidies on fossil fuels, the high initial capital costs requiring additional financing, the lack of an operational plan to implement the policy support in the Fourth FYDP for the promotion of renewable energy and the limited manufacturing sector for renewable energy technologies. Several of the barriers are being addressed and feed in tariffs set at US¢7/KWh have been introduced but there deployment and impact are unknown. In addition, the difficulty of quantifying economic externalities (e.g. fuel price risk for fossil fuels, environmental damage, etc.) further prevents renewable energy resource development from taking place.

International experience on mechanisms to promote renewables:

3.14 Given the difficulty the power sector already faces in financing generation capacity under the prevailing low electricity rates, the incentive to allocate resources to development of renewable energy whether by the public or the private sector remain weak. Under such circumstances, it may be necessary to accelerate renewable energy market development through incentive mechanisms. These mechanisms (policies) would aim to accelerate cost reductions of the renewable technologies through learning and economies of increased production resulting in speeding up the date by when the technologies are economically competitive without the promotional policies. Secondly, such policies have been known to grow strong industries to provide renewable energy systems and equipment that can quickly capture export markets as their technologies become more competitive in other markets.

3.15 In terms of policy instruments, the most effective mechanisms used to date in the world for the development of renewable energy markets, have been feed-in tariffs and renewable portfolio standards. With feed-in tariffs, electric utilities are obligated to allow renewable energy plants to connect to the electric grid, and they must purchase any electricity generated with renewable resources at a fixed, minimum price. These prices are generally set higher than the regular market price, and payments are usually guaranteed over a specified period of time. Tariffs may have a direct relationship with cost or price, or may be chosen instead to spur investment in renewable energy. The example of Germany shows how the use of feed-in tariffs can stimulate – significantly - the growth of renewable energy market, as well as the emergence of a domestic renewable energy technology industry (see Annex 6 for the case study). Laws similar to the Germany Pricing Law have been enacted in Spain, and several other European countries, including France, Austria, Portugal, and Greece, in addition to South Korea. Recently, both Brazil and China have enacted legislation that combines pricing laws and mandated capacity targets.

[26] Hazemi Karegar, H. et al. (2002) *Wind* and Solar Energy Developments in Iran. Paper presented at the 2002 Australian Universities Power Engineering Conference, Melbourne, 29 September – 2 October, 2002.

3.16 Renewable Portfolio Standards (RPS) policy measures legally establish a target for the minimum amount of capacity or generation that must come from renewable energy sources according to a specific schedule leading to a target amount at some future date. The types of renewable resources or technologies that can be used to meet the target are specified and defined as qualifying resources. In addition, fees are usually established for non-compliance. An example of an RPS scheme in the United States is presented in Annex 7.

3.17 Both feed-in tariffs and renewable portfolio standards could be used in the case of Iran to promote renewable energy. A summary of their relative advantages and disadvantages are presented in table 3.2 below.

Table 3.1: Key pros and cons of feed-in tariffs and renewable portfolio standards[27]

	Feed-in tariffs	Renewable Portfolio Standards
Pros	• Can be designed to account for differences in technologies and in the marketplace • Encourage steady growth of small and medium scale producers • Involve low transaction costs • Facilitate financing • Provide easy entry for new players into the market	• Promote the least cost projects • Provide certainty regarding future market share for renewable energy • Perceived as being more compatible with open markets • Are more likely to fully integrate renewable energy into electricity supply infrastructure • Facilitate the establishment of renewable energy credits trading system
Cons	• Tariff difficult to set, particularly at the beginning when the true costs of renewable energy systems are unknown • Overpayments likely to occur and to result in economic inefficiency and unnecessarily high price paid by customers for renewable power • Requirement for domestic production which can involve restraints on renewable energy trade	• High risks and low rewards for equipment suppliers and project developers, which slows down innovation • Instability and "gaming" in the quest for contracts likely to happen due to price fluctuations in "thin" markets • Small investors disadvantaged compared to large, centralized merchant plants • Concentration of projects in areas with the best resources, leading to inequities in the repartition of renewables benefits • No incentive to install more than the mandated level • Complexity to design, administer and enforce • High transaction costs, not very flexible

Source: World Bank analysis, 2006

3.18 It is important to note that price-setting policies (e.g., feed-in laws) have to date been responsible for most of the additions in renewable electricity capacity, while the track record from quantity-setting policies remains uneven. In addition, international experience has suggested that feed-in tariffs are more effective instruments for renewable energy market initiation, while quota systems are more effective at a later market development stage.[28]

3.19 Irrespective of whether a price-setting or a quantity-setting policy is adopted, the critical issue is that cost be spread out over the full customer or population base. In most countries, the additional cost of

[27] Table based on "Comparison of market mandates", paragraph of the World Bank Renewable Energy Toolkit website available at http:///www.worldbank.org/retoolkit (March 8, 2006).
[28] UNDP (2005) "Removing Barriers to Large Scale Commercial Wind Energy Development." GEF Project Document for Work Program. PIMS #747. Available on the GEF on-line project database at http://www.gefonline.org/home.cfm (March 3, 2006).

higher payments to renewable energy producers is allowed to pass through to the consumers. In some countries, the incremental costs are paid through an additional per kilowatt-hour (kWh) charge to consumers, such as the system benefit charges in the US. In a few cases, taxpayers share in the cost, such as in Denmark through a combination of feed-in rates and reimbursement of a carbon tax. In Mexico, a Green Fund supported by government budget and Global Environment Facility (GEF) resources is set up to pay for the incremental costs.[29]

3.20 In Iran, possibilities for financing policy support to renewable energy could include: [30]

- A compensation from the Ministry of Petroleum for avoided fossil fuel use available for the support of renewables[31]; and
- A fiscal/levy mechanism (on carbon for instance) used to create a fund to support renewables.

Energy Efficiency and Demand Side Management:

3.21 Iran was one of the first oil producing and exporting countries in the world to start programs to improve efficiency in the different energy consuming sectors.[32]

3.22 Several institutions are involved in the field of energy efficiency in Iran. The Ministry of Energy (MoE) and the Ministry of Oil (MoO) cover the bulk of the activities, with the latter covering mostly energy efficiency for oil and gas products, and not directly the power sector. The Iran Energy Efficiency Organization (SABA) works as the "operational arm" of the MoE's Energy Efficiency Office, and deals with energy audits, technical consultancy services on energy efficiency, and training.[33] The MoE's Energy Efficiency Office deals with planning and policy making for energy efficiency in the industrial, residential and commercial sectors. It also implements pilot and research projects in the field of energy efficiency. [34]In addition and specific to the power sector, Tavanir has implemented various activities in the field of energy efficiency and demand side management, in collaboration with the RECs, notably the field of T&D losses reductions, and efficient lighting.

3.23 In 1994, an end-use energy efficiency strategy[35] was prepared by the World Bank which suggested that the potential economic energy savings for the period 1994-2005 were about 8,040 GWh (or 2,015 MW) based on the implementation of a set of measures in the residential, commercial, public services and industrial sectors. Table 3.3 below presents the implementation measures which were identified by the strategy to have the most potential for energy efficiency in terms of energy savings and reduction of power demand for the period covered by the strategy.

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[29] Information extracted from the World Bank Renewable Energy Toolkit website available at http:///www.worldbank.org/retoolkit (March 8, 2006).

[30] UNDP (2005) "Removing Barriers to Large Scale Commercial Wind Energy Development." GEF Project Document for Work Program. PIMS #747. Available on the GEF on-line project database at http://www.gefonline.org/home.cfm (March 3, 2006).

[31] Such a compensation, called a Green Fund, has been established in Egypt where up to 4 piasters/kWh (US$75 cents/KWh) is being compensated for avoided fossil fuel use.

[32] World Energy Council (2001) *Pricing Energy in Developing Countries*. World Energy Council, London, UK.

[33] Information available on the website of the Iranian Ministry of Energy at http://www.iranenergy.org.ir (March 17, 2006).

[34] Abdollahshirazi, A. (2004) *Energy Management Promotion in Iran*. Paper prepared for the International Summer School 2004, "Renewable Energy in Schleswig-Holstein. Regional Experience for International Development." 07-13 June 2004, University of Flensburg, Germany.

[35] World Bank (1994) *An End-Use Energy Efficiency Strategy for Iran*. Technical Report. Industry and Energy Division. The World Bank, Washington, D.C.

Table 3.2: Proposed energy efficiency measures for the power sector

Proposed sectoral actions (extract)	Recoverable potential over 1994-2005			
	Power GWh	%	MW	%
Residential, commercial and public services sectors				
Development of natural gas, LPG as substitutes to power	800	10%	100	5%
Household appliances standards and labelling	1,000	12%	200	10%
DSM equipment substitution	1,400	17%	500	25%
Information campaigns	900	11%	200	10%
New buildings and building codes	1,500	19%	400	20%
Public lighting	90	1%	30	1%
Industry				
Load shedding (emergency measures)	200	2%	50	2%
Technical assistance, energy service	350	4%	80	4%
Training of managers and technicians	100	1%	25	1%
Load management for large consumers	1,000	12%	280	14%
Independent generation, cogeneration	700	9%	150	7%
Subtotal for these measures		*91%*		*88%*
Total as proposed by the strategy	8,040		2,015	

Source: World Bank (1994) *An End-Use Energy Efficiency Strategy for Iran*. Technical Report. Industry and Energy Division. The World Bank. Washington, D.C.

3.24 Since the above-mentioned strategy was prepared, several energy efficiency and demand-side management initiatives have been implemented in Iran. However, only some of them have targeted the power sector, and the overall energy intensity of Iran remains higher than that of other countries (see Chapter 1). In the power sector, efforts have been targeted at transmission and distribution (T&D) loss reduction, power supply-side and demand-side management. The efforts have included projects and programs in the following ten key areas:[36]

a. Energy recovery, fuel switching and cogeneration for the power sector;

b. Loss reduction pilot activities for transmission and distribution lines;

c. Load management activities (including pricing mechanisms) in the industrial sector;

d. Installation of smart meters for new and existing connections in the industrial, commercial and residential sectors;

e. Energy audits for energy intensive industries;

f. Development of a domestic Energy Service Company Organizations (ESCO) industry;

g. Efficiency standards for energy intensive industries;

h. Distribution of subsidized Compact Fluorescent Lights (CFLs) and other energy efficient bulbs to residential and commercial consumers;

i. Development of mandatory energy performance labels for fourteen electrical appliances ;

[36] This list of activities is not meant to be exhaustive, and has been drawn up based on the findings of the World Bank Power Sector mission in January 2006, plus some additional literature review among documents available in English.

j. Information, education and awareness campaigns on energy efficient behaviors and technologies (including training programs).

3.25 A detailed description of each of these efforts and their status is presented in Annex 8.

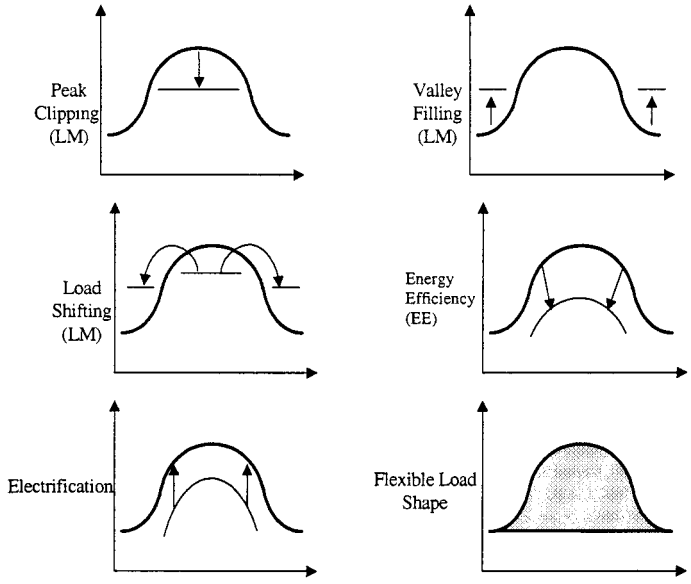
Barriers to energy efficiency:

3.26 As can be seen in Annex 8, while technological and policy options are being applied in Iran to promote energy efficiency, several barriers exist which hamper real achievement. These barriers include lack of adequate information, technical knowledge and training, uncertainties about the performance of investments in new and energy-efficient technologies, lack of adequate capital or financing possibilities, high initial perceived costs of more efficient technologies and lack of incentives for careful maintenance. However, the single most important barrier is the overall low electricity tariff which reduces the incentives to consume less electricity and to invest in energy efficient appliances; leaving large untapped potential for energy efficiency in the power sector, both on the supply side and on the and demand side.

Policy options to step up energy efficiency:

3.27 In an environment where electricity tariffs will increase only gradually, there are limited activities that can be taken and that can also have impact. In the case of Iran, the objectives of energy efficiency in the power sector should be to manage the load (i.e., the demand for power) so that investment needs in new generation capacity can be controlled and the associated financial position of the sector improved. Load management can have a variety of impacts on the load shape, depending on the type of program used (see figure 10 below).

Figure 10: Load Management Strategies



Source: CRA International, 2006

3.28 Based on the initiatives already taken in Iran and international experience from countries with similar characteristics, the activities to continue the focus on should be: (i) loss reduction in transmission and distribution; (ii) load management and smart meters; (iii) energy audits in energy intensive industries and development of an ESCO industry; (iv) distribution of subsidized CFLs and other energy efficient light bulbs; (v) development of mandatory energy performance labels for electrical appliances; and (vi) information, education and awareness campaigns and trainings. A description of what is recommended in each of these areas along with case studies from other countries is presented in Annex 9.

Chapter 4: Financial Performance of the Sector

4.1 *The financial position of the electricity sector in Iran reflects the impact of below cost-recovery pricing policies and associated high consumption of electricity. Indeed, the sector accumulates significant debt year after year to cover capital investments and cash short-falls. These debts represent a direct contingent liability to the Government. If the tariff policy of the Fourth FYDP continues, the sector could accumulate debt amounting to US$50 billion over the coming decade to cover costs. While some publically funded generation will be off-set by investment by the private sector, these transactions will result in significant contingent liability for the Government. Finally, the opportunity cost of the gas used in the power sector to meet the demand for power over the coming decade adds up to close to US$40 billion.*

Introduction:

4.2 Financial revenues and costs in the power sector are consolidated at the level of Tavanir, the electricity holding company responsible for generation, transmission and distribution of electricity. In 2003, the sector generated revenues from sales of electricity and services to end-users amounting to 19,261 billion rials (US$2.4 billion). The net operating income reached 4,475 billion rials (US$0.6 billion), equal to an operating margin of 23%. Loans are provided to the sector to cover cash shortfalls and are primarily provided by state owned banks such as Tejarat, Melli, Mellat and the Central Bank of Iran. The banks provide funds for about 5 years at a charge of 13%-19%. These loans are reported to convert to grants after some years. Overall the collection performance in the sector is good at 90%-95%, excluding the collections of bills from government entities, where military is particularly problematic. Including billings to these consumers would reduce the collection performance to about 70%.

Electricity tariff policy and rates:

4.3 Electricity tariffs are set by the Parliament (the Majlis) and are presented in the FYDPs. The average tariff is determined based on an estimate of the electricity available for sale and the revenue requirements to meet planned investment and operating cost. Based on the average price requirements, the tariff to different consumer categories (residential, public, agriculture, industrial and other/commercial) is determined. The tariff comprises a demand charge, measured in kW for the rate at which the energy is used and an energy charge, measured in kWh, for the variable energy consumed. The tariff in 2003 to the different customer segments is shown in Table 4.1 below.

Table 4.1: Retail Tariffs in 2003

Customer segment	Rials/kWh	US¢/kWh
Residential	97	1.2
Public	152	1.9
Agriculture	14	0.2
Industrial	163	2.0
Other/Commercial	412	5.2
Average	131	1.7

Source: Tavanir (2003-2004)

4.4 The Government allows the electricity prices charged to end-users to cover O&M costs. The actual revenue required to fully cover costs beyond what the tariff brings in is filled by loans from local banks (as described above), bonds, loans from the government and postponement of investments and delayed payments to suppliers. The difference between the revenue required and the tariff charged is presented in Table 4.2 below. The difference is referred to as a subsidy and it is financed by loans and to some extent by deferring expenditures (e.g., investments, maintenance). The loans are reported to convert to grants after some time.

Table 4.2: Electricity tariffs and subsidies in 2003 (rials/kWh)

Consumer category	Cost of supply	Price at which electricity was sold at	Subsidy	Subsidy as a % of set price
Residential	407	97	310	76%
Public	318	152	166	52%
Agriculture	323	14	309	96%
Industrial	289	163	126	44%
Commercial	396	412	-	-
Average	331	132	200	60%

Source: Tavanir (2003-2004)

4.5 Electricity prices were increased by 20% under the Second FYDP (1994-1998), which was marginally greater than the rate of inflation which has been around 15% per annum. Under the Third FYDP (1999-2004), the price increase was capped at 10%. The Fourth FYDP (2005-2010) states that electricity prices should remain at the 2004 level for the first year and that any change in the price for the remaining years of the Fourth plan would need to be approved by the Parliament. It was recently reported that a retail tariff proposal would be presented for approval. A detailed presentation of historical electricity tariffs can be found in Annex 10.

"Cost" of the sector to the Government:

4.6 The lack of cost recovery is having severe implications for the financial well-being of the sector. Consequently, it makes moving from plan to implementation of the envisaged electricity market as well as development of sustainable transactions with the private sector difficult. Moreover, it represents a substantial cost to the Government both in terms of contingent liability and opportunity cost. Details are presented in Annex 11.

4.7 *Sector debt*: By 2003, the consolidated debt of Tavanir reached 20,000 billion rials (US$2.5 billion). Most of the debt is raised to finance investment needs but also to cover cash short falls. The bonds issued as part of the debt raised to finance investments are guaranteed by the Management and Planning Organization and thus represent a contingent liability of the Government. In the present year[37], bonds worth 1,500 billion rials (US$200 million) have been issued.

4.8 Based on the forecast of electricity consumption presented in chapter 1 and in Annex 2, the difference between the tariff charged and the tariff required to cover full costs would average about 42,590 billion rials/year or US$4.7 billion. Over the ten year period, the amount would be close to US$50 billion in constant terms, which would mostly be covered through local bank loans guaranteed by the Government. The analysis and findings in addition to sensitivity analysis is presented below.

[37] The financial year ends March 31.

Electricity Subsidies

Source: Tavanir	Rials	US¢
Average tariff in 2003	132	1.7
Average cost of service supply in 2003	331	4.1

2,129,538 GWh
Over 10 years
≈ US$4.7 billion/year

A sensitivity analysis to assess the impact on the deficit from variations in the natural gas price and depending on the average cost of transmission and distribution in the sector, based on proxies has been undertaken. As illustrated below, the revenue deficit would range from US$1.25 billion to US$4.1 billion (at 3.8 US¢/kWh).

Cost of Supply @ 8 US¢/kWh

	3.3 - 3.8	2.3
Distribution (Int. benchmark)*	1.5 - 2.0	1
Transmission (Int. benchmark)	0.5	
Generation (marginal cost for medium-sized GT)	1.3	1.3

2,129,538 GWh Over 10 years ≈
US$4.1 billion/year @ 3.8 US¢/kWh
US$3.1 billion/year @ 3.3 US¢/ kWh
US$1.25 billion/year @ 2.3 US¢/kWh

Cost of Supply @ 1.3 US¢/mmbtu

	4.1 - 4.6	3.1
Distribution (Int. benchmark)*	1.5 - 2.0	1
Transmission (Int. benchmark)	0.5	
Generation (marginal cost for medium-sized GT)	2.1	2.1

2,129,538 GWh Over 10 years ≈
US$2.75 billion/year @ 3.1 US¢/kWh

* International Benchmark based on mature T&D system

US$4.1 billion represents about 3% in 2004/05 GDP figures. It is important to note that this figure is based on the subsidized price of natural gas. Hence, it does not include the opportunity cost of the gas.

4.9 *Natural Gas Subsidies*: The sector receives a very favorable gas price. Natural gas contracts are entered into between the National Iranian Gas Company (NIGC) and each regional company and the natural gas price to the power sector is 28 rials/m^3 (US¢ 8/mmbtu) compared to an estimated opportunity cost of 420 rials/m^3 (US$1.3/mmbtu). The price increase restrictions that apply to the power sector as described above also apply to the natural gas sector.

Current gas prices in rials/m^3:	
Residential	75
Power	28
Industry	131
Commercial	175

4.10 Based on the future electricity supply requirements to meet demand presented in chapter 2, the sector would consume about 820 bcm of natural gas over the ten year period. At the prevailing estimated difference between the price charged for natural gas to the sector and the assumed opportunity cost, the subsidy would amount to approximately 728,974 billion rials or US$40 billion.

4.11 *Transactions with the private sector*: The favorable gas price also applies to private sector projects. However, this is not an issue per se since all deals with the private sector to date are based on so called energy conversion agreements, whereby the gas is provided free-of-charge by the buyer of the electricity.

4.12 The private sector projects are able to access debt financing through the Oil Stabilization Fund. A rate of return requirement of (ROR) of 23%-25% is the norm, arriving at a selling price, excluding the cost of fuel since it is provided by the buyer, of 1.5-1.7 US¢/kWh. The power is purchased by Tavanir. This model represents a contingent fiscal risk to the Government should the sector not be able to pay for the "private power".

4.13 Looking at the next ten planned BOO projects and the BOT projects, the contingent liability of the Government arising for the take or pay agreements amount to about US$690 million and US$438 million per year, respectively.

Chapter 5: The introduction of a market and competition

5.1 *Iran is laying the foundations for a market to trade electricity. The aim is to introduce a commercial power exchange market whereby bidding and purchasing are driven by competitive pricing and service-quality. To date, the foundations in place have resulted in greater efficiency in the dispatch of electricity by centralizing the function to the system operator/market manager (IGMC). This is the beginning of market reform and, in parallel, will require significant work to, inter alia, enlarge the market, upgrade the quality and capacity of the transmission (and distribution) network and its function, and define system operation rules, implement IT investments to operate the market and build capacity among staff in IGMC. Furthermore, in light of the centralized supply of fuel and lack of fuel diversification, the pricing method applied may need to be revisited to also include a capacity payment mechanism so that bidding generation units can differentiate, and thus compete, beyond O&M costs and heat rates.*

Introduction:

5.2 Iran's power sector has been unbundled and comprises 16 regional electricity companies (RECs) operating within specific provincial/regional boundaries. Each company is responsible for electricity generation, transmission and distribution in its jurisdiction. Tavanir, under the control of the Ministry of Energy (MoE), serves a holding company for the sector and thus has overall responsibility for the sector except for hydroelectricity which falls under the control of the Deputy Minister for Water Affairs. The structure of Iran's power sector is presented in Annex 12.

5.3 Tavanir is the main shareholder of the 16 RECs, which in turn control 27 generating companies and 42 distribution companies. Tavanir also controls other companies dealing with power plant development and construction, project maintenance and management, new energy sources and energy efficiency. Other important institutions in the sector include the Iran Grid Management Company (IGMC) and the Electricity Market Regulatory Board (EMRB).

5.4 In August 2005, the MoE issued a set of "Market Rules" that are intended to transform the emerging electricity market reforms in Iran into a hybrid "electricity pool". The objectives of introducing the market are to achieve more efficiency and quality in the supply of power and to introduce more commercial practices (i.e. prices more reflective of cost) for power purchases and transactions.

5.5 The "Market Rules" introduce a two-tier structure for electricity sale and purchase transactions, comprising:

(i) one tier based on a "centrally scheduled and dispatched" operational regime for Tavanir-owned and/or controlled power generation plants; and
(ii) (ii) another tier for a "semi-centrally scheduled and dispatched" operational regime applicable to autonomous power generation plants (owned and/or controlled by MoE licensees).

5.6 This chapter describes how the current "electricity market" functions, including the main market participants (Box 5.1), describes pricing of electricity in the market, outlines the Government's plans for

future electricity market development and reviews key transitional issues and medium-term market design options that need to be addressed to achieve the vision embodied in the "Market Rules".

Box 5.1: Main Participants In Iran's "Electricity Market"

The "Market Rules" identify the following participants in the Iran's Electricity Market:

- **Electricity Market Regulatory Board (EMRB)** – this seven (7) member body, comprising independent professionals, is appointed by the Minister of Energy to oversee the implementation of the "Market Rules". The EMRB convenes every other week to review performance of the electricity market, deliberate on proposals for modification/adjustment of specific procedures, etc. It is supported by a full-time Secretariat.
- **Iran Grid Management Company (IGMC)** – This autonomous subsidiary of Tavanir performs two (2) critical functions: (i) **Market Manager**, to intermediate the wholesale buying and selling of electricity among all electricity market participants; and (ii) **System Operator/Dispatcher**, to assure safe, reliable and secure grid operations. Although the IGMC does not own the transmission assets, it also functions as the transmission services provider because it retains the "use and control" of the national (400 kV and 230 kV) grid and sets the terms and conditions under which electricity market participants gain grid access, including the "wheeling" of electricity.
- **Power Station Owners** – the majority of power generation plants on the national grid are owned by the RECs and operated by the Tavanir subsidiaries that are referred to as "Generation Management Companies" or GMCs. There are other autonomous public sector entities, such as the Khozestan Electricity and Water Organization. The privately-owned power stations include industrial auto-generation and/or co-generation plants and also the BOO/BOT entities that are being established under "**Energy Conversion Agreements**" with another Tavanir subsidiary – the Iran Power Development Company (IPDC).
- **Suppliers** – these are public or private sector licensees of the Ministry of Energy that retain "use and control" rights over power generation units for the sole purpose of producing electricity for wholesale supply through the national grid to consumers under bilateral contracts. These licensees also may participate in the import and/or export of electricity.
- **Buyers** – these are predominantly the RECs who arrange bulk electricity purchases from the electricity market (through the IGMC Market Manager) for distribution and retail supply to captive subscribers. Other buyers are independent licensees of the Ministry of Energy that may also arrange bulk electricity purchases through the IGMC Market Manager for "third party" consumers, such as autonomous industrial entities.
- **Consumers** – these are entities or persons that receive all or part of their electricity requirements through the national grid based on contracts with one or more Suppliers

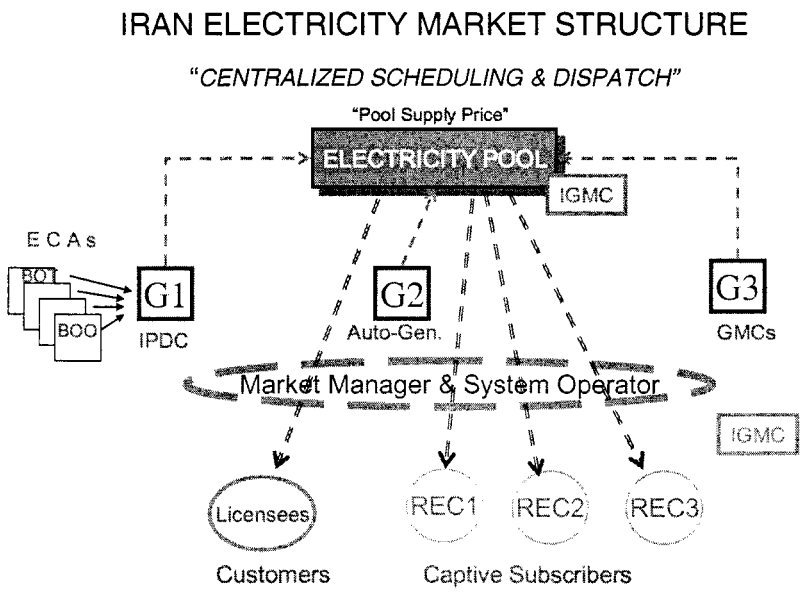
Source: Minister of Energy – Electricity Market Bylaws (issued on 25 August 2005).

Current market structure:

5.7 The "Market Rules" project a basic market structure that is similar in design concept to the original "electricity pool" of England and Wales. Specifically, the "Market Rules" define, in some detail,

the pool intermediation arrangements between the IGMC Market Manager[38] and "Power Station Owners". They also define procedures to be followed by "Buyers" to purchase electricity from the "Market Manager"[39]. Schematically, Iran's emerging pool-based "Electricity Market" is depicted in Figure 11 below.

Figure 11: Electricity Market Structure



5.8 The market structure that has been put in place has achieved efficiency gains in that the most efficient plants' electricity production is dispatched first. As such, the role of the IGMC for the time being is mostly as a central dispatching center for the power production.

Pricing in the market:

5.9 Under the "Market Rules", all "Buyers" - including the RECs - purchase electricity directly from the "generation pool" at a uniform "pool supply price" that is set/regulated by the Electricity Market Regulatory Board (EMRB), based on information/computations provided by the IGMC. The "pool supply price" is computed by the IGMC using a "day-ahead bidding" process that also informs the scheduling and dispatch of available power generation units by the IGMC (see Box 5.2 below on the dual role of the IGMC). Furthermore, the IGMC intermediates the procurement of ancillary services based on prices (capacity availability and energy charges) that are regulated by the EMRB and the Minister of Energy.[40]

[38] Refer to Article 6 of the "Market Rules"
[39] Refer to Article 7 of the "Market Rules"
[40] The IGMC base rate for "available capacity" is derived based on the annuity of investment cost plus O&M cost for reserve generation capacity to sustain security of supply on the national grid. IGMC also pays a base rate for "energy supplied" which reflects the average variable cost of grid-tied thermal power generation units.

Box 5.2: IGMC's Dual Role

The IGMC is both the Market Manager and System Operator for the emerging electricity market in Iran. Specifically, the dual functions of the IGMC involve the following:

- On a day-ahead basis, the IGMC routinely requests bids for the supply of electricity from each "Power Station Owner" and/or "Supplier". Each bid has to be structured as a price-quantity pair for the supply of electricity (energy) from a specific power generation unit. In parallel, Tavanir[41] submits bids for generation units that are associated with "Energy Conversion Agreements" or ECA for BOO and BOT entities. The IGMC as Market Manager determines the system marginal price by stacking all of the submitted day-ahead bids to establish where the resulting supply and demand curves intersect. The "pool supply price" is determined based on the sum of the bid-based system marginal price plus a uniform payment for available capacity ("capacity payments") and projected ancillary services required by the IGMC as System Operator.
- On the day of actual dispatch, the IGMC as System Operator may request any particular "Power Station Owner" and/or "Supplier" to adjust their operations/dispatch positions to help in resolve transmission constraints and/or to accommodate system balancing requirements. The IGMC as System Operator also applies pre-specified ancillary service arrangements with "Power Station Owner" to implement a system-wide "balancing mechanism".
- On the day-after dispatch, the IGMC closes transactions within the "generation pool" and arranges settlements between the "generation pool and each "Power Station Owner" and/or "Supplier". Such pooling and settlement transactions are handled by the IGMC as Market Manager, taking into account "minimum and maximum" price bands that are set by the EMRB. In practice, only about 15% of the settlement transactions are monetized and paid out in cash to participants.
- All other Tavanir-controlled market participants rely on the results of the IGMC as Market Manager's pooling and settlement process to inform Tavanir's internal corporate "clearinghouse" to sort out payment obligations between RECs, GMCs and BOO/BOT entities.

5.10 The uniform "pool supply price" that is set should, in principle, allow all generators to recover costs. More specifically, the price setting procedure for the "generation pool" appears to be as follows:

(i) The IGMC computes a "minimum rate for energy supply" which covers the average variable costs of energy production by the "generation pool" of grid-connected power plants in the Iranian common carrier 230kV & 400 kV transmission networks. This excludes the "embedded power plants" that are connected in the distribution networks of the RECs.

(ii) The IGMC requests day-ahead bids from "Buyers" to purchase energy at different times of the daily pool production cycle. Based on these "pay as bid" prices for energy, the IGMC as Market Manager records the "maximum rate for energy purchases" from the "generation pool".

(iii) For each pricing interval for "day-ahead transactions", the IGMC as Market Manager sets a "market clearing rate for energy supply" that is at least equal to the "minimum rate for energy supply".

[41] Tavanir functions as an aggregator/central trader of electricity produced based on Energy Conversion Agreements with any particular BOO/BOT entity.

5.11 Since there is a uniform price for each type of fuel used for any particular category of power generation plants (i.e., steam power plants, single cycle gas turbines, combined cycle gas turbines, etc.), the only other variable to differentiate between performance of power generation plants is O&M costs and heat rate. But this procedure allows the IGMC to recover costs for the supply-side (i.e., generation pool). Tavanir is then able to administer payments to cover actual contractual costs of BOO/BOT plants from the total pool revenues and also the payment obligations for each of the REC owned power plants. To that extent, the present set up appears to be that of a "cost-based generation pool".

5.12 Under this pricing procedure, it is likely that some licensed "buyers" may, from time to time, bid to pay prices for energy supply that are higher than the average variable costs of energy production by the "generation pool". It nevertheless is unlikely that the RECs (power plant owners) have any incentive to "bid", since they (i) already are guaranteed supply at the "minimum rate for energy supply", and (ii) may not be able to recover the cost of such power purchases from end-use tariffs.

5.13 That said, the above "cost-based generation pool" already applies, de facto, a form of "weighted average price" of energy for all supplies to the RECs. This procedure needs to be revised to fully compatible with the current strategy of promoting BOOs/BOTs based on Energy Conversion Contracts ("tolling capacity contracts") to alleviate capacity constraints. Should the present national uniform fuel pricing policy remain the same for power generation regardless of fuel (gas, fuel oil, diesel) the only avenue left open for the creation of a "power exchange" would be that of a "Capacity Payment Mechanisms" (see Box 5.3 below).

Box 5.3 Capacity Payment Mechanisms

In some wholesale electricity markets where there are concerns over the size of the reserve margin, payments are made both for actual energy produced and also for having generation capacity available for dispatch, even if no electricity is produced. Payments for available capacity can either be through a fixed fee (US$/kW), made by the market manager, and recovered from buyers, or through a "capacity market" which make it compulsory for buyers to purchase sufficient standardized (1 MW) units of available generating capacity to cover demand (plus a specified reserve margin) in their service territory. Buyers therefore make direct payments to owners of generation plants in order to ensure a reserve margin.

In Spain, capacity payments are made to all generators bidding into the day-ahead market. By contrast in NordPool, no capacity payments are made to owners of generation plants; nevertheless, the System Operator in NordPool is allowed to offer a premium above market clearing prices in order to encourage owners of generation plants to make their capacity available for dispatch.

The alternative approach involving a capacity market exists in the "power pool" of New York. The New York Independent System Operator (NYISO) has the mandate not only to set the required reserve margin, but also to assign system-wide capacity requirements, on zonal basis to distribution and supply utilities or Load Serving Entities (LSEs). LSEs are, in turn, required to procure adequate units of available capacity, either bilaterally from owners of generation plants, or from capacity auctions administered by NYISO. The mandate of the NYISO extends to monitoring LSE compliance with these statutory requirements and, where necessary, imposing sanctions on non-compliant LSEs.

A capacity market mechanism similar to that being applied by the NYISO may improve the overall design of Iran's pool-based electricity market and the preferred approach is a capacity contracting obligation. The IGMC could leverage such mechanism to reward owners of generation plants that make capacity availability for dispatch, irrespective of actual production levels. Key features of the mechanism would be that:

- a standard measure of capacity would need to be defined, taking account of the risk of forced outages – the units of trade ("capacity tickets") would represent capacity with a high probability of being available;
- IGMC SO, as the accreditation agency, would award each owner of a generation plant a number of standardized "capacity tickets", taking account of availability records. As is presently the case, IGMC SO would be charged with ensuring that the owner declared capacity is actually operable capacity and also for monitoring availability;
- RECs (or other Buyers) would have to procure sufficient "capacity tickets" to cover their peak MW demand of the year plus a regulatory determined reserve margin (of, say, an additional 30%). RECs may offset this obligation by contracting bilaterally with owners of generation plants, including BOO entities;
- to facilitate the capacity market function, IGMC Market Manager would conduct an auction of "capacity tickets" once or twice a year. Such auctions would inform the setting by EMRB of a market clearing price for "capacity tickets".

Future electricity market development:

5.14 According to the EMRB, there are plans to introduce revisions/refinements to the "Market Rules" so as to allow for hourly differentiation of pool supply prices in the day-ahead bidding process. Measures being contemplated include introduction of: (i) hourly-based differentiation of capacity charges (to be set by IGMC and approved by the EMRB); (ii) a ten-step bidding process to accommodate price-quantity bids for the supply of electricity (energy); and (iii) seasonal adjustment of IGMC payment levels for the supply of ancillary services, such as reactive power, spinning reserves, frequency control, etc. That said, such revisions are not expected to introduce any significant structural changes to the emerging electricity market.

5.15 The market design options being contemplated by the EMRB are common in several other countries. Starting from similar "pool-based" platforms, several European countries made design choices based on country-specific considerations that have significantly influenced the subsequent evolution path of their respective electricity markets. For example, electricity market designs, which are now very advanced in both Spain (OMEL) and Scandinavia (Nordpool), evolved from generically "pooled-based" trading platforms similar to that being put in place in Iran. They nevertheless have evolved into different/contrasting market designs. Spain has retained a centrally scheduled market design for which participation in the day–ahead market is compulsory for all generators over 50MW. By contrast, NordPool has evolved into a competitive market combining bilateral contracts with a self-scheduling market design for which the role of the market operator is to intermediate day-ahead market transactions between five transmission zones. Both market designs are accepted models of competitive power markets that stakeholders in Iran need to consider more carefully. Annex 13 presents a comparison and contrast of key characteristics of the wholesale electricity markets in Spain (OMEL) and Scandinavia (Nordpool), with particular regard to the (i) the scheduling regime; and (ii) the use of single or multiple "pool prices".

Transitional issues and medium-term market design options:

5.16 Overall, the emerging "pool-based" electricity market structure in Iran is conceptually appropriate and operationally feasible, taking into account the relatively large size of the generation segment of the power sector: there are some 400 plus power generation units, the mix of power generation technology is sufficiently broad and main power generation centers are not remotely located relative to the main load centers Teheran, Esfahan, Ahwaz).

5.17 That said, there are several important challenges that will impact successful implementation as well as gaps in the current reform strategy design which need to be addressed. These include:

- There are substantial improvements needed to reinforce the transmission network, not only its capacity (see chapters 1 and 2), but also to improve the information systems (through investments in optic fiber networks, modernized dispatch facilities, etc.) which support transmission of electricity over the network.
- The lack of competition in the supply of fuel and the lack of fuel diversification, limits competition to develop between generating units and limits the competition to O&M and heat rates.
- Under the current set up, key responsibilities for the national grid, including ownership, operation and maintenance, are fragmented and not well articulated[42]. At present, the IGMC as System Operator

[42] For example, the "Articles of Agreement" indicate that the IGMC also has oversight responsibility for implementation of all relevant regulations, standards and procedures required to support the several core mandates also assigned to the IGMC under its "Articles of Association", which are: (i) **Grid System Operator** – to develop, equip and administer the national grid control and monitoring center (the national dispatching center) as well as to

currently relies on and applies regulations, standards and procedures for system operation that were originally put in place for the vertically integrated RECs. These need to be comprehensively re-formulated to ensure alignment with the "Market Rules".

- The IGMC System Operator, in its current configuration, lacks the tools and trained personnel to perform the necessary indicative transmission system planning in support of the other mandate concerning the development/expansion of the grid. A fundamental decision has to be made about the efficacy of retaining the current fragmented ownership arrangement involving 16 different RECs. At the very least, continuation of the current fragmented ownership structure for the national grid under the new regime requires imposition of more complex pooling and settlement procedures between IGMC and the RECs. In other words, the more fragmented the ownership of the national grid, the more complicated the commercial agreements that will have to be negotiated and enforced to ensure that the IGMC is able to guarantee the delivery of non-discriminatory "open access" transmission services to all market participants. Therefore, a consolidation of key segments of the national grid, especially the 400 kV segments,[43] may be called for, not only to secure economies of scale but also to ensure that transaction costs due to the pooling and settlement of electricity flows at the interfaces between REC are minimized. A further benefit of consolidation of the 400 kV networks under a single owner is that supervision and delivery of the numerous ongoing and planned 400 kV transmission projects would be rationalized and streamlined.

5.18 To address the challenges outlined above, the following is needed:

- A review of the investment needs in transmission (and distribution) to support the development of the market, starting with the large load centers but ultimately covering the entire country;
- Build capacity within EMRB and the IGMC in system operation[44], including:
  - ✓ Preparation of new "rules of practice" for system operations, which would be fully compatible with the "Market Rules";
  - ✓ Acquisition and deployment of IT and communications systems (hardware and software) that are adapted to the to the "Market Rules"; and
  - ✓ Acquisition and deployment of computer-aided tools and software programs and simulators to be applied for short, medium and long term system planning and market development.

coordinate and supervise the existing network of regional grid control centers. Such regional grid control centers are owned and operated by the RECs; (ii) **Grid System Development** – to determine and notify plans for the adjustment/expansion of relevant grid systems which are deemed necessary to ensure reliability and security of electricity supply in Iran. Furthermore, to monitor compliance with such adjustment/expansion plans by owners and operators of facilities that constitute the national grid; and (iii) **Grid System Access** – to manage access to, and transit of electricity through, the national grid, especially to assure private sector owners of power plants and/or suppliers (licensees of the Ministry of Energy) of "open access" to the national grid and to facilitate the import and export of electricity in a manner that would promote competition in the electricity market.

[43] The consolidation of the 230 kV transmission networks may not necessarily be justified, since such networks play a dual role in terms of providing the RECs with access to the national grid and also for transmission within individual REC territory.

[44] These actions would strengthen the IGMC's capability to ensure that transitional and medium term arrangement are made to work more effectively and thereby establish a robust operational platform to support the future development of Iran's electricity market beyond the "pooling and settlements" phase into an envisioned "power exchange".

Chapter 6: The role of the private sector

6.1 *Several transactions with the private sector to build power plants are underway in Iran. Competition for new generation capacity has met with significant interest by domestic investors and is resulting in efficiency in the cost of building power plants through the introduction of competition at the bidding stage. Private sector led generation projects also shift the financing burden off of Tavanir, but does not eliminate the Government's exposure given that the transactions are currently based on take or pay agreements backed by Government guarantees. Furthermore, the predominance of the Government in terms of ownership in the domestic investment firms active to date in the sector may hamper ambitions for a power exchange in that it may create perception of collaboration within the Government.*

Introduction:

6.2 The Fourth FYDP indicates, in Article 25 (B), that the Government wishes to encourage "other domestic entities" (*i.e.*, independent power producers (IPPs), distinct from Tavanir) to become involved in the production of electricity. While the plan specifically refers to "domestic" entities, the Government is clearly interested to also attract foreign investors to the sector, as discussed below[45]. The objectives of this plan are to (i) realize the efficiencies of private sector involvement in power plant construction and operation; (ii) shift the burden of supplying capital for power plant construction off of the balance sheet of Tavanir; and (iii) achieve more transparency in the cost of power development (thereby accelerating the debate and the decisions on the need for tariff increases).

Modes of private sector participation:

6.3 To facilitate private sector participation (PSP), the Government has issued a Decree[46] prescribing four basic options for the sale of power from IPP plants, covering both new power plants and plants that a private investor may have acquired from Tavanir:

a. An IPP can sell power directly to end-users, paying the transmission charges prescribed by the IGMC;
b. An IPP can participate in the wholesale market (described in Chapter 4, above);
c. An IPP can sell power to Tavanir under a long-term Energy Conversion Agreement (ECA); and
d. An IPP can sell power to see IGMC under a "guaranteed fee arrangement".

6.4 To date, only the third option is being actively pursued by private investors, reflecting the lack of transparency in setting of tariffs for "third party access" to the grid (by IPPs) and also for "wheeling" power (from an IPP) to end-users (under option 1), compounded by the cumbersome way that IGMC is required to deal with transmission congestion issues while scheduling for real-time dispatch of generation and transmission facilities, according to the "market rules".

6.5 The immaturity and lack of clarity of the "market rules" in the wholesale market, including the lack of transparency in setting/adjusting market clearing prices for energy which underpin amounts

[45] The reference to "domestic" companies (as opposed to foreign companies) arises from the requirement that all foreign investment be made either through shareholdings in a new or existing Iranian company, or through contractual arrangements with an Iranian company (see the section in Chapter 6 on the Foreign Investment Promotion and Protection Act)

[46] Cabinet Decree Implementing Article 25 B of the Fourth Economic, Social and Cultural Development Plan 2005-2009, Articles 2, 4 and 5

offered by the IGMC under the "guaranteed fee arrangement", all act as further barriers to implementation of the options allowed. As discussed below, all of the agreements concluded to date, under the third option, have been ECAs rather than PPAs.

6.6 The PSP effort has been managed by two implementing groups organized under Tavanir, one for transactions involving BOO agreements and one for BOT agreements. In Iran, BOO schemes have typically involved and targeted domestic investors, while BOTs have typically been targeted at foreign investors. Box 6.1 describes the three most common models for PSP in the power sector. Because there are no ownership restrictions in Iran, it has not used the Build Transfer Operate model.

Box 6.1: Common Ownership Models for Private Power

BOO – Build-Own-Operate – This common technique calls for an investor to take responsibility, on an indefinite basis, for construction, ownership, and operations of the project. It is normally initiated by a contract for the output of the power plant. Also known as the perpetual franchise model, the Build-Own-Operate model entails a private entity building, financing and operating the project under a perpetual franchise from the host government. The project developer retains title to the assets. Within this model, all financial support for project-related borrowings is provided by the private entity. The government regulates safety, quality of service and, possibly, user charges or profits. The perpetual franchise model can accommodate financing in the public securities market. However, in view of the innovative nature of many projects and the attendant economic risks, the public securities markets, both for debt and equity, will usually be available only after a project has operated successfully for a few years and has established an acceptable record of profitability.

BOT or BOOT – Build-Own-Operate-Transfer – This scheme is similar to BOO but has a future transfer of ownership to a designee, typically the government. The future transfer can be very important where a project has unique characteristics that preclude permanent private ownership, such as hydroelectric power stations. The private entity receive a franchise to finance, build and operate the project for a fixed period of time, after which ownership reverts to the host government (or some local or regional public authority administered by the host government). Ownership reversion is planned to occur only after the private sector entity receive the repayment of, and a satisfactory return on, the capital it has invested in the project. In return for the ownership reversion, the host government might be asked to furnish some limited credit support for project borrowings. The BOT structure is attractive to the host government because of the ownership reversion feature.

BTO – Build-Transfer-Operate – This scheme is used in jurisdictions where private ownership is not permissible, but private operation is desirable. A private entity designs, finances, and builds the project. The entity then transfers the legal title to the host government (or some local or regional public authority) immediately after the project facility passes its completion tests. The private entity then leases the project facility back from the public authority for a fixed term. A long-term lease agreement gives the private entity the right to operate the project facility and to collect revenues for its own account during the term of the lease. At the end of the lease term, the public authority operates the project facility itself or hires someone else (possibly the private entity originally involved) to operate it. Under this model, the host government or public authority has, at most, only a very limited responsibility for the project's financial obligations; the project company has the principal responsibility.

6.7 In Iran, there are two principal assumptions driving the differentiation in schemes to domestic and foreign investors: (i) that foreign investors cannot own land; and (ii) that foreign investors wish to avoid

residual ownership. With regard to the first assumption, it appears that the requirement for local ownership of land can easily be met by the incorporation of a local entity or establishment of a branch in Iran. Concerning (ii), international experience in IPPs indicates that investors generally view positively the net residual value of power stations at the end of their initial contract periods (*e.g.*, after 20 years), although it is too early to say what investors have actually done with their residual projects because most IPP contracts are still running. It is, however, true that most investors, when evaluating a project, assume a minimal value for residual assets, as any remaining value is perceived to be offset by demobilization costs.

6.8 Although there is no right or wrong approach, most developing power markets prefer the BOO scheme for most power projects, although BOT schemes are still actively used where there is a unique site (*e.g.*, a hydroelectric dam) or other local considerations. But for projects where siting is less important (as is usually the case with thermal projects), the current trend is to favor BOO structures. Additionally, many national utilities expect to lack the operational skills in 20 years when these power stations are reaching the end of their initial contract periods, and changing this would require a presumptive change in government policy that moved power generation into the private sector in the first instance. In the case of Iran, the sector is going through significant reform and, possibly, restructuring, which may make it difficult to identify who would take a power plant back in the case of BOT schemes.

6.9 To date, Tavanir has been arranging for the private ownership of land in the BOO projects, and land leases or usufructs in the BOT projects. International experience supports the use of land leases or usufructs in BOT projects, where there is high certainty that the assets will transfer after the initial contract period. However, international experience is not consistent on BOO projects, where many investors appear content to enter into long-term extendable land leases that forgo any residual value in the land.

6.10 For both BOO and BOT projects, ECAs rather than PPAs have been used. The substantive difference between these two (as these terms are commonly used in the IPP industry) is that a PPA has a fuel component and an ECA does not. However, it is important to stress that PPAs do not necessarily transfer the fuel risk to investors, as the fuel component is often a pass-through in the rates charged. However, even where it is a pass-though, there is risk that the pass-through will not be respected simply because higher tariffs bring higher political risk. In addition, it is not necessary to have a fuel component (as in a PPA) to hold investors responsible for the plant heat rate. In international experience, PPAs are much more common than ECAs, but, for the reasons stated, this distinction is not particularly meaningful. The reason ECAs are being used in Iran is that fuel supply is under a monopoly, and the risk of gas supply is considered to be better managed by the public entities.

Box 6.2: IPPs and Competitive Power Markets

Given the intention of the Government to create a more competitive wholesale power market, care should be taken in designing the Iranian IPP program in a manner that does not interfere with the development of that market and that is flexible to further power market reform.

The problem, essentially, is that long-term ECA/PPA agreements can distort power markets, and make effective competition more difficult to obtain. If the IPPs with long-term ECAs/PPAs do not participate in the market, it reduces the liquidity of the power supplies available for competition. In addition, the ECAs/PPAs may hinder the ability of the off-taker (i.e. Tavanir), to reorganize itself in accordance with the new market structure.

A good discussion of this problem, and the solutions initially attempted in various jurisdictions, can be found in the World Bank Policy Research Working Paper No. 2703, *Integrating Independent Power Producers into Emerging Wholesale Power Markets*, available at http://rru.worldbank.org/PapersLinks/Open.aspx?id=575. Much of this paper deals with the integration of pre-existing IPPs (with long-term PPAs) into newly established competitive markets. However, the paper also touches upon designing new PPAs that contemplate the development of such markets, which contain:

(i) provisions designed to encourage IPPs to participate in the market for the purpose of supplying ancillary services and relieving congestion;

(ii) provisions designed to mandate the gradual entry of the IPP into the market, through progressive assumptions of market risk; and

(iii) provisions designed to achieve greater balance or "symmetry" in the buyout and termination clauses, so that there are appropriate incentives and penalties for both the IPP and the off-taker when the transition is made to full market participation.

It would also be worthwhile for the GoI to examine the steps currently being taken by RAO UES in Russia, a state-owned utility that is attempting to create a competitive market while simultaneously attracting private investment in new generation. In particular, it would be worthwhile for Iran to monitor the development of new types of flexible PPAs that are currently being drafted for this purpose in Russia, that are designed to accommodate the transition to a competitive market while still protecting the financial interests of the IPP investors. It is proposed that these new flexible PPAs will have the following features:

(i) the IPP will be a market participant when full production begins, but on a special basis, whereby the prices that are bid by the IPP into the market cannot be higher than the prices agreed upon by the IPP and the off-taker;

(ii) the IPP will receive payments for the ancillary services that it supplies to the system operator; and

(iii) there will be flexible termination provisions, whereby both the IPP and the off-taker will have options to terminate the PPA on a financially symmetrical basis.

Box 6.3: The Extent of Competitive Power Markets

In the case of developing countries, few countries at present have advanced competitive wholesale power markets. A number of countries have initiated the move towards wholesale competition, but only to fine-tune such initiatives along the way. Two countries with comparable economy size, number of population, and electricity demand with Iran are Egypt and Thailand. The following summary is for comparison purposes and provides an insight into these countries' experience with competition in the power sector.

<u>Egypt</u>

- With a $79 billion economy and a 72 million population, Egypt's installed generating capacity totaled 18 GW in 2005.
- Egypt commenced a period of unbundling electricity distribution, with the aim of a full corporatization, as far back as 1964 and only to re-bundle distribution and generation again in 1998.

- In parallel, the first round of a highly competitive IPP scheme was awarded in 1998/1999 with 3 IPPs now operational (approximately 11% of installed capacity), albeit the plan for additional 12 IPPs was cancelled due to the fall out of the deep devaluation of the Egyptian Pound that significantly raised the first IPPs' tariffs in local currency.
- Heavy natural gas subsidy and the absence of fuel supply competition are becoming less sustainable as the opportunity cost of exporting natural gas rises in tandem with higher global price and Egypt's gas export activities.
- At present, Egypt is at a junction of a few broad options:
  - (i) additional generation capacity to be developed by the national electricity utility with public funding sources (Egyptian Electricity Holding Company);
  - (ii) revised IPP scheme that contemplates a higher component of local currency tariff and financing and a component of embedded bilateral off-take with industrial/commercial users;
  - (iii) preparation and subsequent actions for the establishment of a competitive wholesale power market, including the setting up of systems operator and commercialization of distribution entities; and
  - (iv) broad-based electricity tariff adjustment towards covering economic costs .
- Egypt's experience with competition in the power sector is therefore limited to IPP project development. The next challenge for Egypt would be to integrate and converge state-owned and IPP power plants towards the chosen wholesale power market structure.

Thailand

- With a $161 billion economy and a 63 million population, Thailand's installed generating capacity totaled 25 GW in 2005.
- Thailand's first significant step towards liberalizing the sector started in 1992 with a sale of selected state-owned power plants to newly established and subsequently publicly-listed genco, followed by a similar transaction in 2000. Both gencos remain publicly-listed with some foreign shareholdings, but are under significant control of the state-owned utility at present. Both gencos have self-financed the purchase of the original power plants and been active with the acquisitions of later IPPs and SPPs.
- The generation sector was opened for private competition in the early/mid 1990's with the approval of 7 IPPs and an on-going approvals of small power producers (SPP; inclusive of renewable energies and biomass fuels) scheme. As of 2005, IPPs, SPPs and the aforementioned gencos represent 39% of the country's installed capacity and 52% of GWh produced. Transmission and distribution activities have remained government-owned until today.
- Following the 1997 economic crisis, many state-owned enterprises were slated for privatization. This was also the time when a blueprint for competitive power market was drafted and contemplated. With economic recovery in the early 2000s and a series of change in leadership of the government and of the energy sector, the plan for competitive power market was discontinued following what was happening in other major developing Asian countries such as India, Indonesia, Malaysia and the Philippines.
- The potential options for Thailand include:
  - (i) a second-round of competitive IPP scheme that contemplates a higher component of local currency tariff and a diversification from natural gas;
  - (ii) continuation of SPP scheme with emphasis on renewable energies; and
  - (iii) the race for fast, low-cost and efficient project development with the ability to sell electricity on a standardized and transparent PPAs.
- Thailand's experience with competition in the power sector is also limited to IPP project

development. With a single-buyer system in place, one main challenge is in maintaining or enhancing the level of competition in IPP project development. A sound anti-competition rule is therefore crucial going forward.

Current projects with the private sector:

6.11 The private sector participation projects in Iran currently focus on gas-turbine power stations. The following are the proposed BOO projects and their status:

Table 6.1: Proposed BOO Projects (first 10)

Project Name	Sponsor	Size (ISO)	Status
1. Rood'e shoor	Arian Mahtab Gostar	2112	Under construction
2. Mashhad (Toos Development)	Mapna	954	Under construction
3. Zanjan 4	Bank Melli Investment Co.	544	ECA signed
4. Gheshm Island	Hirbodan	160	ECA signed
5. Hormozgan	Azar Ab Energy Co.	500	ECA signed
6. Assalluyeh	Bonyad Mostazafan va Janbazan	500	No ECA yet
7. Zanjan 3	Sanat Energy Tamin	500	No ECA yet
8. Assalluyeh 2	Mapna	942	No ECA yet
9. Semnan	Sarmayeh Gozari Tamin Ejtemaii	500	No ECA yet
10. Ali Abad	Mapna	950	No ECA yet

Box 6.4: Case study: efficiency gains from the Rood'e shoor project:

Rood'e shoor is the first large scale private power plant in Iran. The plant, which is currently under construction, is a 2,112 MW single cycle plant consisting of eight gas turbine units of the V94.3A type manufactured by Siemens each with a capacity of 264 MW at ISO conditions. The project is being implemented in three phases, with the first phase under construction.

The project is expected to deliver efficient electricity to the power sector in the following ways:

- ✓ price for electricity more reflective of real cost as it includes market cost of capital
- ✓ expected to be completed on time, due to a firm financing plan up-front
- ✓ expected to operate according to plan, due to an O&M contract with Siemens

The plant is being constructed by the Arian Mah-Taab Gostar Company, an Iranian company comprising shareholdings by various development investment companies, including the Kerman Development Investment Co and the Molal Development Investment Co. Financing for the plant includes both foreign and local costs, with the foreign costs (€224.5 million for phase 1) comprising 85% export credit, 10% commercial facility and 5% equity all from Siemens. The local financing (350 billion Rials) is in the form of equity from the shareholders. An ECA has been signed with Tavanir to purchase the power and energy.

Source: site visit to Rood'e shoor in January, 2006.

6.12 Many of the BOO projects listed above include quasi-governmental entities. Indeed, the term private sector" in Iran includes companies that may not officially be part of the state but which nevertheless have significant connections with the Government. As a result, those domestic investors who have participated in the IPP programs to date are, in many instances, wholly or partially owned or controlled by government or quasi-government entities. In terms of the success of the IPP program, these projects will bring greater efficiency only if the quasi-governmental investors demonstrate corporate governance and financial discipline comparable to the fully private sector. Furthermore, the ownership and/or controlling stake by the government could have serious implications for the future development of the power trading market, due to the perception that some market participants may engage in collaborative and non-competitive behaviors.

6.13 The following are the BOT projects:

Table 6.2: Proposed BOT Projects

Project Name	Sponsor	Size MW at site condition	Status
South Isfahan	Mapna International, Iran Foreign Investment Company Holding AG (IHAG)	734	Operational
Pareh Sar	Gruppo Falck, Mapna International, DSD Dillinger Stahlbau GmbH	900	Project company shareholders changing
Tabriz	Xenel	1000	Prepared for ECA signature
Fars	Mapna International, Quest Energy Middle East Ltd.	735	ECA signed
Ali Abad	Saudi Oger Ltd, International Power plc, Sojitz Corporation	863	ECA under negotiation
Genaveh	TBD	500	To be bid

6.14 As can be seen from Table 6.2, there has been a relative lack of interest in Iranian IPP projects by 'truly foreign' investors. Instead, most of the investors are actually Iranian entities using offshore investment vehicles. This absence of conventional foreign investment has continued to exist notwithstanding the above-noted range of options available for the sale of power from IPPs, and notwithstanding the provisions set out in the Foreign Investment Promotion and Protection Act (FIPPA) and the associated legislation described below in Chapter 7.

6.15 Clearly, one of the impediments for foreign investment is the perception of 'country risk'. In all likelihood, this perception is not primarily attributable to the Iranian legal or regulatory framework (indeed, the FIPPA legislation seems to be in general conformity with international practices) but, rather, it is, more probably, a function of geo-political tensions. Accordingly, until such tensions are abated, substantial foreign investment in the sector is unlikely. Having said that, some investors from certain countries may actually see an advantage in the geopolitical inhibitions of Western investors (e.g. Chinese, Indian).

Box 6.5: Measuring Perceptions of Country Risks

Foreign IPP investors naturally view country risks as much higher than host governments and local investors. Investors often use outside analysts to help them gauge country risks. One such

subscription service is the *International Country Risk Guide* (ICRG).[47] For each country, the ICRG looks at political, financial, and economic risk factors. The financial and economic factors would not appear to have much subjectivity, being measures of such things as liquidity, wealth, budget, and foreign exchange positions. On the other hand, political risks would appear to have a greater degree of subjectivity. They are subdivided in the ICRG into components and subcomponents, as follows:

Government Stability
- ✓ Government Unity
- ✓ Legislative Strength
- ✓ Popular Support

Socioeconomic Conditions
- ✓ Unemployment
- ✓ Consumer Confidence
- ✓ Poverty

Investment Profile
- ✓ Contract Viability
- ✓ Profits Repatriation
- ✓ Payments Delays

Internal Conflict
- ✓ Civil War
- ✓ Terrorism
- ✓ Civil Disorder

External Conflict
- ✓ War
- ✓ Cross-border Conflict
- ✓ Foreign Pressures

Future prospects of the Private Sector Participation (PSP) program:

6.16 The PSP program that Iran has embarked upon in the power sector should be able to achieve, at least partially, some of the objectives of introducing private sector efficiencies in power plant construction and operation, in addition to shifting the burden of such construction and operation off of the balance sheet of Tavanir. However, the current design of the program (particularly in regard to the procurement issues discussed below), and the overall risk profile that Iran currently has in the eyes of prospective investors – particularly foreign – suggest that the benefits of private sector efficiencies may be limited to the benefits that domestic investors can bring. Further, as has been the case in many countries that have embarked on similar programs, there will likely be 'trade-offs' in terms of accommodating the financial and security needs of IPP developers, and the medium and long-term implications of IPP contractual arrangements for the future development of the Iranian power market, as discussed above in Boxes 6.2 ands 6.3 on IPPs and competitive power markets.

Box 6.6: Benefits of Domestic Investors

While foreign investors bring international experience and off-shore financing, there are significant benefits that domestic investors might contribute, for example:

[47] Published by The PRS Group, Inc. (see www.prsgroup.com).

1. Exposing electricity consumers to foreign exchange fluctuation risks on capital investments should be avoided, if possible or mitigated. This argues strongly for financing in local currency, which unfortunately is possible only in larger economies with well-developed bank or capital markets. In developing a project, investors need access to long-term funding and a reasonable interest rate (pre-and post-construction) relative to their risk-adjusted return on investment. To avoid exposing consumers to interest rate fluctuations, investors are also typically required to fix interest rates. Here, domestic investors may have an advantage over foreign investors through their ability to accept local treasury management instruments such as short-term hedging, ability to absorb county risk and relationships with local financiers.[48]

2. Domestic investors can invest in local currency and may accept local currency tariff. This allows for a higher component of the IPP tariff to be denominated in local currency (especially the non-fuel costs). The mismatch of foreign-currency denominated project cost and local currency sources of funds (debt/equity) can be more easily managed during the shorter project development stage, relative to the life of the project.

3. Typical IPP projects have an intricate web of contractual underpinnings and documentation designed to allocate every conceivable risk to one party or the other. Domestic investors, being a part of the local community, often are willing to forego some of the complexity, resulting in faster transactions with less transaction costs. It also may facilitate the procurement/agreement of local contracts, enhance local project understanding and support and ease resolution of disputes.

4. Domestic investors often have greater access to lower-cost and capable local specialists, or regional specialists with direct experience in the country/sector offering discounted professional fees, thus keeping operations costs under control by relying less on expensive foreign specialists.

5. In the case of Iran, there is evidence that domestic investors are bringing commercial, private-sector, perspectives to the development of new IPP plants. Accordingly, there would appear to be reasonably good prospects for efficiency gains being realized through the IPP program, notwithstanding the absence of interest from conventional foreign investors.

Source: World Bank

6.17 It is beyond the scope of this Note to review in detail the procurement procedures being used by Tavanir to solicit the private sector. However, from the types of issues being raised in regards to soliciting and contracting of IPPs, some comments are appropriate. The most significant point is that virtually all of the issues that have been drawn to the attention of the World Bank team have been encountered in other countries before. Accordingly, the GoI should be able to obtain structuring and procurement advice from international consultants that specialize in this subject and that can offer workable solutions to the problems.

6.18 Tavanir would be well served if it were to engage international financial and legal advisors to guide them through, and advocate on their behalf, a pilot IPP project. Highly experienced consultants are not inexpensive but, for the first major initiative, would be worth the expense. Fixed or capped fee arrangements with such consultants are now commonplace. The financial structuring and legal components could be engaged as a package or separately. The structuring consultants are most often from an investment bank, consulting company, or engineering consulting company. Despite their high

billing rates, the top tier legal firms will have the most experience and depth of knowledge. Not involving the appropriate advice up-front can have long-term detrimental impacts (see box 6.7 below).

Box 6.7 Case study: Nigeria – Emergency Power

One example of the value of international advisors comes from Lagos, Nigeria. In 1999, Nigeria was emerging from years of military rule and had no experience with transparent procurement. With the national utility in disarray, the State of Lagos took it upon itself to negotiate a contract for emergency power with Enron Corporation. Enron was to relocate some pre-built power generating barges to the Lagos lagoon and later supplement these barges with a land-based power station nearby the existing Egbin power station. Late in the process, the Federal Ministry of Power and Steel and the National Electric Power Authority were brought into the negotiations.

The State of Lagos asked the World Bank to comment on the final draft of the contract. Comparing this draft contract with IPP contracts from around the world clearly showed that there was an imbalance in negotiating power. Although on the surface the power price was not unattractive for emergency power, the contractual arrangements significantly biased the risk allocation in favor of Enron (and to the detriment of Nigeria). Of course, Enron was a highly talented company and had engaged highly talented outside legal counsel for negotiations. The Nigerians had relied on inexperienced in-house legal counsel. Enron had covered every conceivable risk, leaving Nigeria highly exposed to contingent liabilities.

Fortunately, since the project had not yet been implemented, Nigeria was able to renegotiate the contract and get out of some of the onerous conditions. The land-based power station was separated into a separate contract, which has been deferred. In the end, the barges in fact delivered much-needed power to Lagos.

6.19 The recommendation is to engage international consultants to put together a model IPP transaction on a pilot basis, which would constitute a useful precedent even if the IPP investment in question is ultimately made by a domestic entity. The consultants can create a bidding form of ECA (or PPA), Government Support Agreement, Land Lease (or Usufruct), and other forms of contract (e.g., water supply, backup fuel) to form the Security Package for the IPP. These forms of agreements will be based on Iran's needs in the context of a rich experience of IPP investing around the world. The consultants will also develop a detailed set of Instructions to Bidders to attract qualified bidders. The consultants can solicit Expressions of Interest, recommend a short-list, manage the bidding process, including a transparent clarification process, evaluate technical and financial bids, and make recommendations as to the final award. While Tavanir is perfectly capable of doing these things by itself, having an internationally recognized firm visible in this process will enhance the perceptions of bidders, each of whom will be weighing the expenditure of significant time and monies to prepare a bid.

6.20 No less important is to engage legal counsel experienced in IPP transactions in other jurisdictions. Contrary to expectations, experienced IPP investors consistently prefer to sit opposite experienced advisors because they will then have confidence that reasonable solutions will be negotiated, based on precedents in other countries, when issues arise. It is important to note that despite best efforts in preparing the forms of contract that are included in the Request for Proposals, a complex long-term business relationship cannot be fully anticipated by just one party in advance, and some negotiation on non-tariff contractual undertakings is always necessary.

6.21 Furthermore, in the vast majority of IPP investments, limited recourse lending is included in bid structuring. Lenders, with their relatively modest margins, and typically no upside potential, will look

most carefully at contractual structuring to avoid taking on risks. Again, experienced advisors can be invaluable in guiding Tavanir through a pilot project.

6.22 The international legal advisers will, of course, need to work closely with lawyers who are familiar with Iranian law. Further, the legal team will have to be familiar with the proposals that the GoI is developing for the future establishment of a more competitive power market in Iran. This latter consideration is significant, since, as mentioned above, the PPAs (or ECAs) entered into between Tavanir and the IPPs should be designed so as to avoid, or at least mitigate, the problems that other jurisdictions have faced in attempting to integrate older forms of PPAs into a new competitive market environment.

6.23 In summary, experienced advisors should be able to assist in Iran in minimizing the 'trade-offs' noted above, both in terms of meeting of the financial and security needs of the investors, and in terms of the impact of IPP plants on the development of the Iranian power market over the medium and long terms.

Chapter 7: Legal and regulatory framework

7.1 *Major conceptual frameworks have been put in place and agreed to for the development of the power sector and several institutions are up and running to implement advanced and sophisticated market models and transactions with investors. Nevertheless, the key legislation dates back to 1967 and despite Tavanir being charged in 2002 to draft new legislation for the sector reflecting the new policy directions, the law from 1967 remains in place and has yet to be replaced by an up to date legal framework.*

Introduction

7.2 The preceding chapters of this note, particularly Chapters 5 and 6, have already referred to some of the key elements of the legislative and regulatory framework of the Iran power sector. Against this background, this Chapter presents a summary consolidation of the key legislation and regulations that impact the sector.

Law of Electricity Organization of Iran; July 10, 1967

7.3 This legislation, which is almost 40 years old (predating the establishment of the Islamic Republic of Iran in 1979), remains in force as a fundamental pillar of the legal framework of the power sector. The law gives wide powers to the former Ministry of Water and Power (whose responsibilities have now been assumed by the Ministry of Energy -- see below) to organize and control the power sector throughout the country. These wide powers include the ability to establish the various regional electricity companies[49] and to control, through the issuance of licenses, the operations of those companies plus other government-owned, privately-owned and municipally-owned entities engaged in the generation, transmission, distribution or sale of electricity.[50] The Ministry also has the ability to set tariffs.[51] Further, this Law gives the Ministry a general power to issue regulations governing the activities of companies in the sector[52] -- which is still used as the basis for some of the market establishment regulations recently promulgated, as discussed below.

7.4 In 2002, the Ministry of Energy[53] assigned Tavanir the task of preparing a new law for the sector, dealing with, inter alia, the protection of consumer rights; arrangements for the import and export of electricity; and licensing provisions designed to promote private participation in the sector. However, as of yet a new legislation has not been approved by the Parliament (Majlis). Given the significant changes that have taken place the Government's plans and commitments to a competitive power market, independent regulation and private participation in the sector, a modern Electricity Act should be prepared and enacted as soon as possible.

Law Establishing the Ministry of Energy; June 1, 1978

7.5 This Law, originally passed in 1974, designates the Ministry of Energy (MoE) as the successor to the Ministry of Water and Power. It gives the MoE policy-setting responsibilities in the energy sector,

[49] Law of the Electricity Organization of Iran, Articles 2 and 3
[50] Ibid, Articles 5 and 6
[51] Ibid, Articles 9 and 10
[52] Ibid, Article 12
[53] Tavanir Power News, Issue 43, November 2002, available at http://news.tavanir.org.ir/nashriat/PwNews/SubNews.asp?NashriehNO=43&NewsID=48

including the power sector, as well as specific coordination responsibilities for the production, operation, transit and distribution of energy, again including electricity.

7.6 In 1978, the Law was amended to give the MoE explicit responsibilities for the construction and operation of nuclear power plants.[54]

Law of the Fourth Economic, Social and Cultural Development Plan 2005-2009; September 1, 2004

7.7 The Legislation adopting Iran's five-year plan for 2005-2009 (the Fourth FYDP) is a foundation enactment by the Parliament. The key provision in regard to the electricity sector is Article 25 B, as follows:

> "*While preserving its responsibility in the provision of electricity, government is bound to determine by the end of the first year of the fourth plan, the conditions for production and guaranteed purchase price of electricity in order to encourage other domestic entities to get into production of electricity as much as possible through the power plants out of managerial and supervision jurisdiction of the Ministry of Energy.*"

7.8 As indicated in Chapter 6 of this note, this Article documents the desire of the Parliament to encourage "other domestic entities" (i.e. independent power producers, distinct from Tavanir) to become involved in the production of electricity. As is also noted in Chapter 6, the reference to "domestic" companies (as opposed to foreign companies) arises from the requirement that all foreign investment be made either through shareholdings in a new or existing Iranian company, or through contractual arrangements with an Iranian company (see the section below on the Foreign Investment Promotion and Protection Act).

Cabinet Decree Implementing Article 25 B of the Fourth Economic, Social and Cultural Development Plan 2005-2009; June 29, 2005

7.9 This Cabinet Decree is the instrument that identifies the options for private investment described in the section on "Modes of private sector participation" in Chapter 6 of this note.[55] This Decree also deals generally with the Tavanir PPA/ECA agreements, including the prices to be paid for the power purchased under such agreements.[56] Further, there are provisions dealing with the purchase of power at guaranteed prices by the IGMC, including provisions dealing with natural gas fuel price adjustments and special incentive provisions for renewable energy and co-generation plants.[57] Finally, the Decree provides that it does not apply to electricity exports.[58] Given that the arrangements set out in this Decree are critical to potential private investors in the sector, it would be preferable if those arrangements were embodied in primary legislation, such as the above-mentioned new electricity law.

Cabinet Decree Establishing the IGMC; September 20, 2004

7.10 This Cabinet Decree establishes the Iran Grid Management Company (IGMC), and sets out its duties and responsibilities.

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[54] Law Establishing the Ministry of Energy, Article 1 (Q) and (R)
[55] Cabinet Decree Implementing Article 25 B of the Fourth Economic, Social and Cultural Development Plan 2005-2009, Articles 2, 4 and 5
[56] Ibid, Articles 6 and 7
[57] Ibid, Articles 8, 9 and 10
[58] Ibid, Article 12

7.11 Although the IGMC does not own the transmission network in Iran, it does have responsibility for the operation of the grid[59], including all dispatch functions[60]. In addition, the Decree gives the IGMC responsibilities for key aspects of the development of the competitive power market in Iran, including:

- the establishment of the competitive terms for purchase and sale of electricity and the establishment and administration of the market itself[61];
- the development of strategies to expand private investor participation in the sector[62];
- the implementation of non-discriminatory grid access arrangements, on the basis of competitively procured capacity rights[63]; and
- the preparation of reports, for Tavanir and the MoE, on the status of competition in the power sector[64].

7.12 The IGMC is not a fully independent entity, in that its shares all are indirectly owned by Tavanir, and there is provision in the Cabinet Decree for Tavanir to be represented on the IGMC Board of Directors[65]. The IGMC is also bound by policy directives given by the MoE[66]. The IGMC operates on a not-for-profit basis[67]. Given the centrality of the IGMC in the new, competitive, market arrangements, and the desire to encourage private investor participation in the sector, it would be preferable if the IGMC were completely independent of Tavanir, reporting solely to the MoE.

Ministerial Order Establishing the Electricity Market; August 16, 2005

7.13 The initial version of this Ministerial Order was issued on August 25, 2003, and the August 2005 version is the first revision. As indicated in Chapter 5 of this note, this important Ministerial Order establishes a number of the key features of the Iranian power market, including the regulatory agency, the EMRB, which oversees the operation of the Market Rules.[68] The Ministerial Order also identifies the mechanisms by which the IGMC controls market transactions[69] and the rules for relinquishing power stations.[70]

7.14 As has been noted above in regard to other items of subordinate legislation, it would be preferable if the important provisions of this Ministerial Order were embodied in a law adopted by the Parliament. Indeed, as a Ministerial Order, this particular instrument would seem to have even less permanency than the Cabinet Decrees discussed above. Of particular concern is the fact that it is this Ministerial Order which establishes the EMRB as the key regulatory agency. Given the composition of the EMRB, it is clear that the government wishes it to have a degree of independence, especially from Tavanir. To support this desirable quality of independence, the EMRB enabling provisions should be found in primary legislation.

[59] Cabinet Decree Establishing the IGMC, Article 2(1)
[60] Ibid, Article 7(1)
[61] Ibid, Article 2(3)
[62] Ibid, Article 2(4)
[63] Ibid, Article 7(8)
[64] Ibid, Article 7(10)
[65] Ibid, Article 16
[66] Ibid, Article 29
[67] Ibid, Article 33
[68] Ministerial Order Establishing the Electricity Market - Revised Version, Article 5
[69] Ibid, Articles 6 and 7
[70] Ibid, Article 8

The Foreign Investment Promotion and Protection Act (FIPPA); March 2002 and the FIPPA Implementing Regulations; July 2002

7.15 The FIPPA legislation passed in March 2002 and the accompanying Implementation Regulations introduced in July 2002 are modern enactments designed to encourage and protect foreign investment in Iran, including investments in the power sector.

7.16 Two basic types of foreign investment are contemplated in the legislation:[71]

- Foreign Direct Investment, in those sectors where private investment are permitted, through the mechanism of foreign ownership of shares in an existing or new Iranian company; and
- Foreign Indirect Investment, in all sectors of the economy, through the mechanism of contractual arrangements such as Joint Venture arrangements, Buy-Back arrangements and BOT arrangements.

7.17 It is noteworthy that, on the website of the Organization for Investment, Economic and Technical Assistance of Iran (OIETAI), the government organization responsible for administering FIPPA, the reference in the legislation to "BOT arrangements" is defined as including "BOOT, BOO, BLT, ROT etc. schemes."[72]

7.18 Certain provisions in the FIPPA legislation and Implementing Regulations apply to both direct and indirect foreign investments. These include the following significant provisions in regard to investor rights:

- there is a guarantee of foreign capital against nationalization;[73] and
- investors may convert profit and capital gains to a foreign currency, or into goods, and repatriate same.[74]

7.19 In regard to foreign direct investments, it is noteworthy that there are no restrictions on the level of foreign shareholding in a particular enterprise.[75]

7.20 In regard to foreign indirect investments, the following provisions are particularly relevant to power sector investments through the mechanism of a BOT-type scheme:

- the inclusion of "generation, transfer and distribution of electricity" as permitted areas of foreign investment[76] (but it should be noted that the legislation explicitly prohibits the granting of concessions to foreign investors if this would lead to such investors being "in a monopolistic position"[77]); and
- provisions for compensatory payments in the event of a change in law, and for the guarantee of any payments to be made by government purchasers of goods and services (such as electricity) resulting from a foreign investment project.[78]

[71] FIPPA, Article 3
[72] OIETA website, at http://www.investiniran.ir/pages(english)/rules.htm
[73] FIPPA Legislation, Article 9; and the FIPPA Implementing Regulations, Article 4 (a) 4
[74] FIPPA Legislation, Articles 14 to 18; and the FIPPA Implementing Regulations, Article 4 (a) 5
[75] FIPPA Implementing Regulations, Article 4 (b) 1.2
[76] Ibid, Schedule on "Sectors and Sub-sectors referred to in Para (d) of Article (2) of FIPPA"
[77] FIPPA Legislation, Article 2
[78] FIPPA Implementing Regulations, Article 4 (b) 2.1 and 2.2

Additional Guarantee Provisions found in the Annual Budget Laws

7.21 As a result of concerns expressed by prospective Independent Power Producers as to the adequacy of the above-noted guarantee provisions in the FIPPA Implementing_Regulations, the Parliament has begun to include, in each year's Budget Law, special provisions permitting the Ministry of Finance to offer prospective IPPs a separate guarantee to secure Tavanir's contractual obligations to purchase power generated in the plants owned by the IPP.

7.22 An example of these special guarantee provisions can be found in the 2004 Budget Law, which provides that:

> *"In implementing the Foreign Investment Promotion and Protection Act, approved on March 10, 2002, the Cabinet is hereby authorized to take action in order to attract foreign investment in electricity generation plans from water, steam, gas, combined cycle, storage pumps, new energy and energy transfer up to a capacity of 12,000 megawatts.*
>
> *In order to fulfill this Paragraph, the Government is hereby authorized, in addition to the guarantees that can be offered within the framework of the Foreign Investment Promotion and Protection Act, approved on March 10, 2002:*
>
> *1 – To take action towards guaranteeing the payment of the contractual commitments of Iran's governmental corporations that are parties to contracts (whose goods and services must ultimately be purchased by the government).*
>
> *2 – If, on the basis of government decision or prevailing law, the selling price of products (goods or services) produced by these plants to customers is less than its guaranteed purchase price by the government or governmental corporations from the investor, the difference would be forecast in the annual budget by the National Organization of Management and Planning, and its payment would be guaranteed by the government (the Ministry of Economic Affairs and Finance)".*

7.23 If the GoI intends to offer these additional guarantees on a continuing basis (notwithstanding the current difficulties in attracting foreign investment discussed above in Chapter 6), it would be sensible to amend the FIPPA legislation and/or the implementing regulations to consolidate all of the relevant guarantee provisions in one location.

Annex 1 a: Historic consumption of electricity (1995-2003)

Electricity consumption
GWh

	1995	1996	1997	1998	1999	2000	2001	2002	2003
residential	23374	23993	26523	28686	29754	31226	32891	34946	37967
public	6203	6595	6727	7077	10622	11271	11951	12630	13714
agricultural	5402	5731	6009	6782	8019	9147	11079	12435	13859
industrial	21390	22925	23661	24140	26504	28937	30739	33469	36951
commercial	7655	7622	8160	8484	5567	5991	6394	6925	7461
others	1830	2805	2278	2477	4190	3754	4117	4672	4672
total	65854	69671	73358	77646	84656	90326	97171	105077	114624
Electricity consumption per capita	1117	1143	1205	1255	1349	1419	1506	1603	1726

Customer numbers
thousand

	1995	1996	1997	1998	1999	2000	2001	2002	2003
residential	10408	10441	11385	11881	12502	13072	13683	14377	15041
public	317	290	350	355	436	465	523	558	599
agricultural	34	36	40	44	51	60	78	89	106
industrial	52	55	69	75	81	86	91	99	110
commercial	1463	1579	1706	1772	1805	1896	1970	2030	2120
others	2	452						18	23
total	12274	12401	13550	14127	14875	15579	16345	17153	17976
Electricity consumption per consumer GWh	5365	5618	5414	5496	5691	5798	5945	6126	6377

Source. Tavanir, 2003-2004

Annex 1 b: Electricity exports and imports, GWh (1992-2003)

Year	Export								Import					Net
	Nakhjavan (Azerbaijan)	Turkey	Armenia	Azerbaijan	Turmenistan	Pakistan	Afghanistan	Total	Nakhjavan (Azerbaijan)	Armenia	Azerbaijan	Turkmenistan	Total	
1992	82							82						82
1993	195							195						195
1994	197							197						197
1995	157							157						157
1996	283	101						384						384
1997	283	175	64					522						522
1998	302	225	95					622		144			144	477
1999	349	302	475					1125		340			340	785
2000	283	289	410	20				1003		326			326	677
2001	389	251	224	185				1049		315	430		745	305
2002	464	5	328	2				799		330	620	27	977	-178
2003	569	126	159		1	47	17	919	negligible	323	582	582	1489	-570

Source: Tavanir.

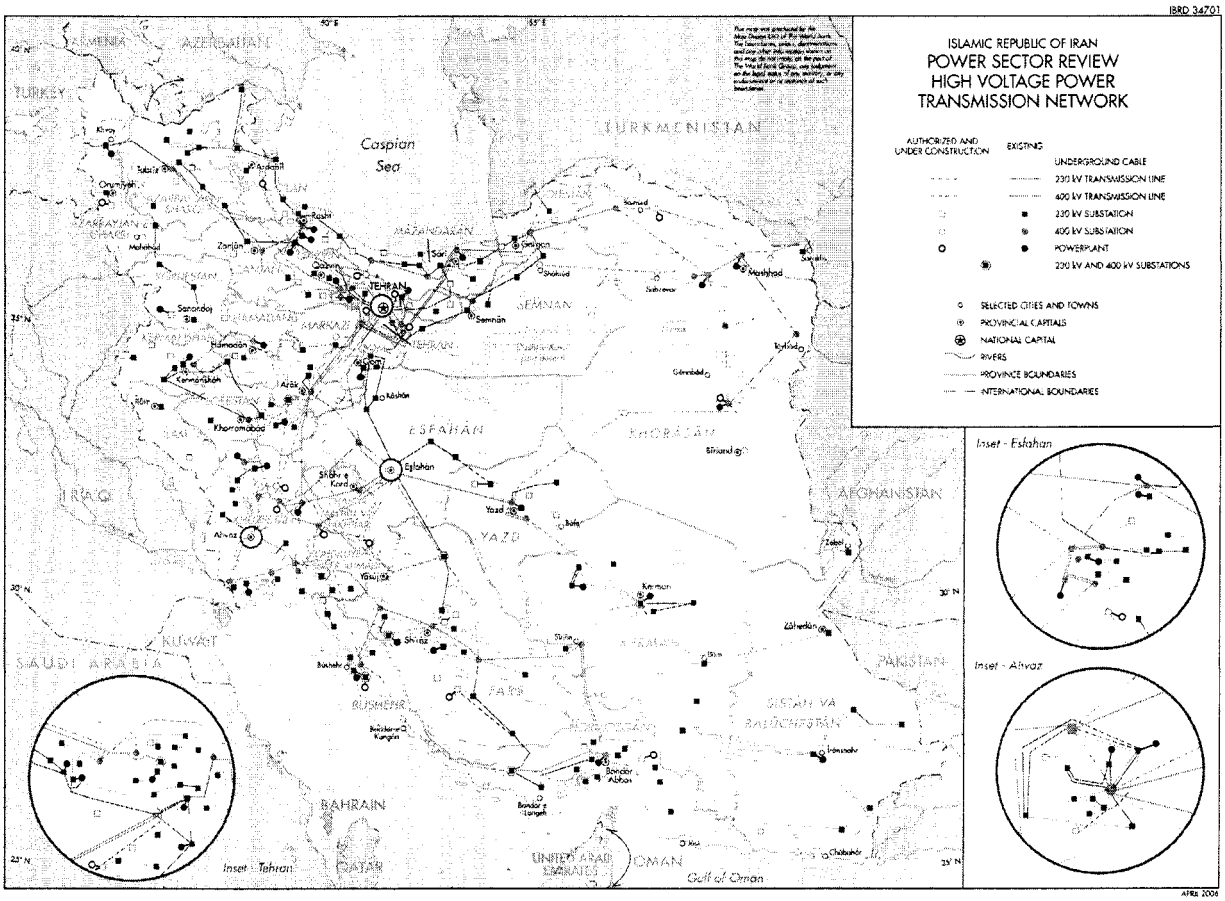
Annex 2: Forecast of electricity demand

(8.6% demand growth)

	Load MW	Consumption GWh
2005	31,494	175,528
2006	34,074	190,623
2007	37,053	207,017
2008	40,189	224,820
2009	43,762	244,155
2010	47,501	265,152
2011	51,484	287,955
2012	55,797	312,720
2013	60,500	339,614
2014	64,843	368,820
2015	69,473	400,539

Source: World Bank analysis 2006

Annex 3: Network Map



Annex 4: Demand Scenarios and Savings Potential

Electricity consumption rate of growth

		base case	scenario 1	scenario 2
Consumption growth	%	**8.6%**	**7.0%**	**5.5%**
2005	GWh	175,528	175,528	175,528
2006	GWh	190,623	187,815	185,182
2007	GWh	207,017	200,962	195,367
2008	GWh	224,820	215,029	206,112
2009	GWh	244,155	230,081	217,448
2010	GWh	265,152	246,187	229,408
2011	GWh	287,955	263,420	242,026
2012	GWh	312,720	281,860	255,337
2013	GWh	339,614	301,590	269,380
2014	GWh	368,820	322,701	284,196
2015	GWh	400,539	345,290	299,827
2015 consumption saving	%		-14%	-25%
Cumulated consumption 2005-2015	GWh	3,016,944	2,770,464	2,559,812
Cumulated savings 2005-2015	GWh		246,481	457,132

MW of GT capacity saved compared to base case

		scenario 1	scenario 2
2005	MW	-	-
2006	MW	386	748
2007	MW	833	1,602
2008	MW	1,347	2,573
2009	MW	1,936	3,673
2010	MW	2,608	4,916
2011	MW	3,374	6,317
2012	MW	4,244	7,892
2013	MW	5,230	9,660
2014	MW	6,343	11,639
2015	MW	7,599	13,852

Calculation assumes all capacity saved is in the form of large gas turbines (159 MW boiler plate) operating at a plant factor of 83%.

Natural gas savings

			scenario 1	scenario 2
2005	bcm		-	-
2006	bcm		0.72	1.39
2007	bcm		1.55	2.98
2008	bcm		2.51	4.79
2009	bcm		3.61	6.84
2010	bcm		4.86	9.16
2011	bcm		6.29	11.77
2012	bcm		7.91	14.70
2013	bcm		9.74	17.99
2014	bcm		11.82	21.68
2015	bcm		14.15	25.80
			63.15	117.12

Conversion using average derated heat rate of 9150 Btu per kWh

Annex 5: Detailed technology-specific assumptions for levelized generating cost calculations

Source: World Bank	Units	Medium/Large Gas Turbine	Small Gas Turbine	Combined Cycle gas turbines	Steam Plant	Hydro (indicative)	Wind
Installed Capacity	[MW]	159	30	477	320	500	30
De-rating by Altitude and Temperature	[%]	15%	15%	15%	15%	-	-
De-rating by Use	[%]	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
Gross Effective Capacity	[MW]	134.7	25.4	404.0	271.0	498.0	29.9
Internal Consumption	[%]	0.6%	0.8%	1.6%	6.4%	0.3%	0.0%
Net Effective Capacity	[MW]	133.9	25.2	397.6	253.7	496.5	29.9
Unitary Investment	[US$/kWinst]	296	361	497	628	600	1000
Total Investment	[MUS$]	47.13	10.83	236.85	200.90	300.00	30.00
Investment Annuity	[MUS$/year]	5.91	1.21	23.96	20.32	28.85	3.76
Forced Outage Rate	[%]	6.1%	7.5%	6.7%	7.8%	1.6%	4.5%
Average Scheduled Maintenance	[days/year]	40	35	43	56	15	21
Annual Average Availability	[%]	84%	84%	82%	78%	94%	90%
Theoretical Energy Generation	[GWh/year]	1,172.68	220.82	3,482.65	2,222.40	4,349.39	261.75
Expected Maximum Energy Generation	[GWh/year]	980.27	184.61	2,865.29	1,734.68	4,102.25	235.59
Plant Factor	[%]	83%	83%	81%	73%	40%	30%
Expected Energy Generation	[GWh/year]	973.33	183.28	2,820.95	1,622.35	1,739.76	78.52
Heat Rate (ISO conditions)	[kBtulhv/kWh]	9.05	9.05	6.21	8.06	0.00	0.00
De-rating by Temperature and humidity	[%]	0.7%	0.7%	0.7%	0.7%	0.0%	0.0%
De-rating by Use	[%]	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
Average Heat Rate	[kBtulhv/kWh]	9.15	9.15	6.28	8.15	0.00	0.00
Fuel Variable Cost	[US$/MWh]	0.79	0.79	0.54	0.70	0.00	0.00
Non-fuel Variable Cost	[US$/MWh]	0.73	0.64	0.45	0.64	0.11	0.00
Total Variable Cost	[US$/MWh]	1.52	1.43	0.99	1.34	0.11	0.00
Annual Fixed O&M Cost	[MUS$/year]	0.16	0.43	0.67	1.09	1.21	1.09
Total Annual Fixed Cost	[MUS$/year]	0.16	0.43	0.67	1.09	1.21	1.09
Total Annual Fixed Cost	[US$/MWh]	0.17	2.34	0.24	0.67	0.69	13.91
Investment	[US$/MWh]	6.07	6.62	8.49	12.52	16.58	47.89
Total Average Cost	[US$/MWh]	7.75	10.39	9.72	14.54	17.38	61.80
Firm Capacity Recognition	[%]	85%	85%	85%	85%	85%	85%
Plant Life	[years]	15	20	30	30	50	15
Capacity Income	[US$/MWh]	5.30	7.62	7.42	11.22	14.68	52.53
Energy Income	[US$/MWh]	2.45	2.77	2.30	3.32	2.70	9.27
Total levelized cost	[US$/MWh]	7.75	10.39	9.72	14.54	17.38	61.80

Other assumptions used to calculate levelized costs

Exchange rate and discount rate

Exchange rate Rials/US$	1US$= Rials	9000
Discount rate	%	10%

Temperature and altitude

Average Temperature	ºC	20
Reference Temperature	ºC	15
Average altitude	m	1078
Reference altitude	m	0
Humidity	%	39%

Source. World Bank.

Annex 6: Germany's Experience with Feed-in Tariffs

In the early 1990s, Germany had virtually no renewable energy industry and, in the view of most Germans, the country was unlikely ever to be at the forefront of alternative energy sources. Yet, by the end of the decade, Germany had transformed into a renewable energy leader, with a new, multibillion-dollar industry and tens of thousands of new jobs.

Driven by growing public concerns about security of energy supply, and environmental impacts including global climate change, the German government passed a new energy law in 1990 that required utilities to purchase the electricity generated from all renewable technologies in their supply area, and to pay a minimum price for it. The "Electricity Feed-in Law" was inspired in part by similar policies that had proved effective in neighboring Denmark.

The law has been adjusted numerous times since it entered into force in 1991. Most significantly, in 2000, the German Bundestag required that renewable electricity be distributed among all suppliers based on their total electricity sales, ensuring that no one region would be overly burdened. Additional technologies, such as geothermal power, were included under the new law. Also, with help from scientific input and the various renewable industries, the Bundestag established specific per kilowatt-hour payments for each renewable technology based on the real costs of generation. Electric utilities also qualify for these tariffs; a change that the government correctly expected would reduce utility opposition while further stimulating the renewable energy market.

The German Renewable Energy Act of 2000 sets specific feed-in tariffs for various renewable energy technologies for a period of 20 years, based on their generation cost and generation capacity. The aim is to secure pioneering markets for renewables, and to support technological learning through large-scale market introduction.

The law covers electricity from wind (on- and offshore), biomass plants of up to 20MW, photovoltaic, hydro and geothermal. Generally, the tariffs decrease for newly installed plants. The electricity from renewable energies is distributed proportionately amongst grid operators, according to the amount of electricity supplied to customers (flexible shares at the transmission system level). All electricity suppliers are obliged to purchase from their regional grid operator an equal share of electricity from renewable energy (flexible shares at the electricity supplier level).

Pricing is based on fixed norms unique to each technology, which in turn were based upon estimates of power production costs and expectations of declines in those costs over time. For example, wind power prices remained at the previous level of DM 0.17/kWh for plants commissioned in 2001, but only for the first five years of operation, after which prices paid declined. Solar PV prices were set initially at DM 0.99/kWh. All prices had built-in declines over time (i.e., 1.5% annual decrease in starting tariffs paid for wind power plants commissioned in subsequent years). This provision addressed one of the historical criticisms of feed-in approaches, which was that they did not encourage technology cost reductions or innovation. The new law's provisions for regular adjustments to prices addressed technological and market developments. The law also distributed the costs of the policy (i.e., the additional costs of wind power over conventional power) among all utility customers in the country. This issue of burden sharing had become a significant political issue in Germany by 2000 because the old law placed a disproportionate burden on utility customers in specific regions where wind power development was heaviest.

So far, the Feed-in Tariffs have been a success in massively increasing wind energy generation, and accelerating biomass and solar technologies. In 2004, the Law was revised again to also cover larger-scale hydro, and differentiating tariffs between biomass types, and size of plants. EU countries like Austria, Belgium, Denmark, France and Spain have adopted similar legislation, and Brazil (among other developing countries) is in the process of establishing a comparable scheme.

Germany also addressed the challenge of high initial capital costs of renewable energy through low-interest loans offered by major banks and refinanced by the federal government. The "100,000 Roofs" program, which expired in 2003 (and has since been replaced with higher PV tariffs), provided 10-year low-interest loans for PV installation. Income tax credits granted only to projects and equipment that meet specified standards have enabled people to take tax deductions against their investments in renewable energy projects. In addition, the federal and state governments have funded renewable resource studies on- and off-shore, have established institutes to collect and publish data, and have advanced awareness about renewable technologies through publications of subsidies and through architectural, engineering and other relevant vocational training programs.

Source: World Bank Renewable Eneregy Toolkit website at http://www.worldbank.org/retoolkit (March 8, 2006)

Annex 7: Texas Renewables Portfolio Standards[79]

Under the Renewables Portfolio Standard (RPS) in Texas, retail electricity suppliers are required to include a specified percentage of renewables in their generation portfolio. Annual renewable energy generation targets back the policy. Texas state authorities have set targets to increase the amount of energy generated by renewables to 2,880 MW by 2009, including 2,000 MW from "new renewables" (i.e., modern biofuels, wind, solar, small-scale hydropower, marine, and geothermal energy). Wind energy currently dominates the installed capacity of renewables, with supply costs of around 4.7 cents/kWh (of which 1.7 cent/kWh is covered by a federal production tax credit).

Reports show that the first-year target of 400 MW of new capacity installed by 2003 was exceeded significantly. Several factors are contributing to the policy's success: clear renewable energy targets, clear eligibility of what qualifies as a renewable resource project, stringent non-compliance penalties, a Tradable Renewable Energy Certificate system that encourages flexibility and minimizes costs, and a dedicated regulatory commission that fully involved numerous stakeholders during the detailed design of the policy. A major lesson from Texas is that, although new and relatively untested as a policy tool, the RPS, in combination with tax credits, has the potential to cost-effectively support the establishment of a robust renewable energy market.

Source: G8 Task Force on Renewable Energy, Final Report, June 2001.

[79] Information obtained in: UNDP, UNDESA and World Energy Council (2004) *World Energy Assessment: Overview 2004 Update*. United Nations development Program, New York.

Annex 8: Detailed description of energy efficiency measures in the power sector under implementation

1. Energy recovery, fuel switching and cogeneration for the power sector

Since the early 1990s, supply side activities have been implemented in the power sector with the objective of improving energy efficiency[80]. The key activities include:

- The conversion of existing gas power plants to combined cycle;
- The implementation of energy recovery projects such as installation of turbo-expanders[81] and co-generation (CHP) in power plants. Energy recovery projects in the gas turbines in Kish Island (Persian Gulf) and from the Tabriz power plant are successful examples of CHP projects designed and implemented in collaboration with the Ministry of Energy; and
- Various co-generation projects have been implemented in several cities.

The development of supply-side energy efficiency activities has been successful overall, but the low electricity tariff has made it difficult to justify the projects from an economic point of view. For most of the supply-side energy efficiency activities, the financing of the needed equipment remains too costly for such measures to be widely implemented in the present tariff context[82].

2. T&D losses reduction activities

Due to the relatively high rate of T&D losses, it is a priority for the Iranian power sector to implement measures for loss reduction. Efforts have focused on the distribution side given the larger share of the losses in this part of the network.

To assess what can be achieved; pilot projects have been implemented in each Regional Electricity Company for one or two zones of their distribution network in recent years, under the supervision of Tavanir.[83] In practice, project component actions have covered, inter alia, the replacement of low voltage by medium voltage cable, installation and/or rehabilitation of transformers, and overall improved maintenance of the installations. The pilots have shown that with investments of about US$90 per customer, it has been possible to achieve a 4% reduction in distribution losses. At the current level of tariff, such investments do not make economic sense[84], but they could be viable if focused on zones where customers are the most energy intensive (e.g., industrial zones). However, due to the level of investment required, and budget shortages experienced by Tavanir, the pilot measures have not been extended as far as envisaged. Thus the effects of this particular effort remain somewhat limited.

[80] Information available on the website of the Iranian Ministry of Energy at http://www.iranenergy.org.ir (March 17, 2006).
[81] Devices that recover power from flue gas or process gas streams.
[82] Based on discussion with Tavanir in January, 2006.
[83] Based on discussions with Tavanir in January, 2006.
[84] Based on using an average power tariff of about 132 Rials/kWh (2003 data), the savings realized on the total power consumption correspond to about US$ 75 million only.

3. Load management/shedding/TOU activities in the industrial sector

Because of rapid growth in demand for power, Iran is now turning towards load management activities, especially in the industrial sector, where most of its energy intensive consumers are. The efforts to date have been somewhat modest, mainly focused on stimulating voluntary or mandatory load shifting through the introduction of:

- Mandatory holidays (5-7 days) for big industrials during the summer peak: if such engagement is not respected, industrial consumers are penalized by being the first disconnected in case of load shedding[85]; and
- Monthly changes to basic tariff rates (per kWh or per kW depending on the tariff structure chosen), in order to stimulate load shifting towards cheaper periods of the year.[86]

The design of more elaborate mechanisms for load shifting should be possible once better data is available on consumption patterns. The activities undertaken in the field of smart meters are contributing to reaching that stage (see paragraph below).

4. Installation of smart meters

As agreed under the Fourth FYDP, Iran has started to install smart meters at selected customers' connections in order to make better use of load management activities. The related by-law under the FYDP gives Tavanir the responsibility to buy and the RECs to install smart meters as follows[87]:

- By 2009, all of new and existing connections in the industrial and commercial sectors should be equipped with smart meters;
- By 2009, about 30% and 20% of –respectively - all new and existing connections for urban residential consumers[88] should be equipped with smart meters.

In total, more than 5 million smart meters should be installed in the next five years for industrial, commercial and residential consumers.[89]

5. Energy audits for industrial facilities

Energy audits have probably been the most common initiative in Iran in the field of industrial energy efficiency. Audits have been conducted by various agencies, SABA, IFCO, but also Tavanir) and most of them have not focused on the power sector only.

In order to stimulate the implementation of the measures recommended in the audit, the Iranian government also developed a financial facility for energy efficiency projects with the following characteristics:[90]

[85] Based on discussions with Tavanir, January, 2006.
[86] Based on discussion with Tavanir, January, 2006.
[87] Based on discussion with Tavanir, January, 2006.
[88] Priority will be given to the consumers with big power consumption and/or demand within the urban residential sector. (based on discussions with Tavanir, January, 2006.)
[89] Based on discussion with Tavanir, January, 2006.

- 100% of the costs of new and demonstration projects can be financed;
- Up to 50% of the costs of energy audits and measures implemented can be financed for projects with high energy saving potential; and
- Payment of the bank loan's interest in the case of high cost measures with high energy savings potential.

As of 2004, energy audits had been conducted in more than 70 factories. These audits have led to the implementation of various measures, resulting in about 85,000 tons of crude oil savings per year.[91]

6. Development of a domestic ESCO industry

International experience suggests that the most important factor in the creation of an energy efficiency market is the emergence of Energy Services Companies (ESCOs). At present, about 40 ESCOs exist in Iran, working on energy auditing and on the installation of smaller-scale energy efficient equipment and fuel combustion settings.[92] However, the impact of the existing ESCOs - in terms of energy savings – is difficult to assess. In addition, the lack of technical expertise in the field of large industrial energy efficiency is affecting the development of a more effective ESCO industry, despite some recent initiatives to tackle this issue (e.g., in 2005, an MOU was signed between Iran and Japanese ESCOs to provide Iranian ESCOs with training on how to implement industrial energy efficiency audits and measures).[93]

7. Efficiency standards for energy intensive industries

Due to the large share of energy consumption coming from the industrial sector, the GoI has set up some mandatory energy efficiency targets for the following industrial sub-sectors: cement, brick and ceramics, tires, glass, agriculture, pulp and paper, textiles, aluminum, food oils, sugar, and chalk and lime.[94] These do not focus on the power sector per se, but should have an impact on electricity savings/load reduction.

Under the Fourth Development Plan, new targets have been set for the period 2005-2009. In case of consumption above the targets, the industries are fined by having to pay an extra 20% for the energy

[90] Abdollahshirazi, A. (2004) *Energy Management Promotion in Iran*. Paper prepared for the International Summer School 2004, "Renewable Energy in Schleswig-Holstein. Regional Experience for International Development." 07-13 June 2004, University of Flensburg, Germany.
[91] UN Economic and Social Commission for Asia and the Pacific (2004) *End-Use Energy Efficiency and Promotion of a Sustainable Future*. Energy Resources Development Series No. 39. United Nations, New York, USA.
[92] Some of the ESCOs mentioned are: Yekta benideh Tavan, Bareen energy, Sepahan, Pishran Energy Persia, Ehdas Control, Tabeh Rayan Energy, No Andishan Energy Novin, Shianak, the center for environmental and energy research and studies, and Samen Niro.
See: article on the Second Gathering of Managers of ESCOs in Iran, Scientific-technical monthly magazine of electrical power industry, No. 106, March 2005. Also available on the Tavanir website at http://news.tavanir.org.ir/nashriat/mahbarq/Subnews.asp?NashriehNO=106&MahbarqBG=15 (March 21, 2006).
[93]. See: article on the Second Gathering of Managers of ESCOs in Iran, Scientific-technical monthly magazine of electrical power industry, No. 106, March 2005. Also available on the Tavanir website at http://news.tavanir.org.ir/nashriat/mahbarq/Subnews.asp?NashriehNO=106&MahbarqBG=15 (March 21, 2006).
[94] UNDP / GEF Proposal for PDF Block B Grant for the Iran's Industrial Energy Efficiency Program (IEEP), available on the GEF website at http://www.gefonline.org (March 17, 2006).

consumed.[95] In order to help the industries reach their target, supporting legislation was passed that an energy management department be created in all large-scale industries.[96]

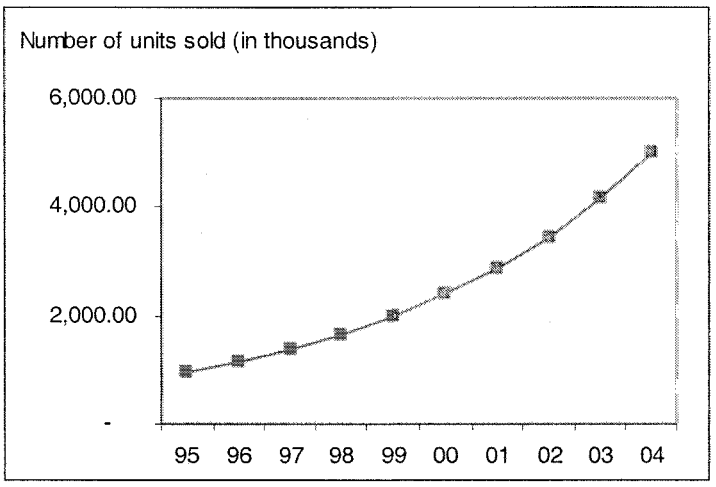
8. Energy efficient light bulbs and Compact Fluorescent Lamps

Activities intending to make use of the economic benefits[97] of Compact Fluorescent Lamps (and other energy efficient bulbs) were started in 1995, with the objective of stimulating the creation of a domestic market, supported by a domestic manufacturing industry. Most of the lamps/bulbs are sold to consumers at subsidized prices, under a scheme whereby manufacturers receive a subsidy from the state on the production costs for the CFLs, which are then channeled through specific retail shops proposing energy efficient lamps for sale. Other lamps are also bought by Tavanir and distributed directly by RECs to customers, who can repay for the CFLs through their electricity bills.[98] The subsidy on energy efficient bulbs depends on whether the customer's residence is in a rural area (70% subsidy) or in a city (40% subsidy)[99]. In parallel, information campaigns have been implemented (by RECs, Tavanir and by the Ministry of Energy) to raise awareness among electricity consumers, including the public sector.

Up to now, about 15 million subsidized energy efficient lamps have been disseminated through this mechanism, at a present rate of 5 to 6 million bulbs per year. Such diffusion has also stimulated the overall efficient bulbs market which now is estimated at about 25 million units sold in 10 years (see figure 6.A below).[100] However, the potential for development of the efficient bulbs market is still much higher, and could reach at least 30 million units per year if properly stimulated.[101] The Fourth FYDP aims at a distribution of more than 25 million CFLs by 2009.

[95] Information based on discussion with Mr. Hasanzadeh, Director of Electrical DSM Department at Tavanir, on January 16, 2006.
[96] UN Economic and Social Commission for Asia and the Pacific (2004) *End-Use Energy Efficiency and Promotion of a Sustainable Future*. Energy Resources Development Series No. 39. United Nations, New York, USA.
[97] An economic analysis on CFLs dissemination's economic benefits in Iran was prepared in 2003 by a consultant for Tavanir, and concluded that CFLs could bring economic benefits to Iran of about US$ 20 / bulb sold at subsidized price. In this estimation, the economic benefits are about 8 times as high as the costs to buy and procure a CFL. (Calculation based on data extracted from the Powerpoint presentation of Noorgestar Co. Ltd entitled "Economic analysis of CFL diffusion in Iran", prepared for Tavanir. The printed document was provided to the World Bank by Mr. Lavaee, Distribution Manager at Tavanir, on January 18, 2006.)
[98] Based on discussion with Mr. Lavaee, Distribution Manager at Tavanir, on January 18, 2006, the latter CFL distribution scheme has not been such a success in Iran, partly due to resistance from Regional Electricity Company to take on the responsibility of selling the lamps and consider it as part as their core business.
[99] Mainly for income distribution reasons, the Iranian government assumes that rural consumers should be more subsidized than urban consumers.
[100] Data based on discussions with Mr. Lavaee, Distribution Manager at Tavanir, on January 18, 2006.
[101] This calculation is based on the assumption that there are 20 million potential customers in the country, that each could install on average 5 CFLs, for which the average lifetime is 3 years. (Data based on discussions with Mr. Lavaee, Distribution Manager at Tavanir, on January 18, 2006.)

Figure 8.A
CFL market development (modeled) 1994-2005[102]



Due to rapid demand growth in Iran, it is reported that it has not been possible to properly monitor the effects of CFLs diffusion on energy consumption and peak demand.[103] Some studies based on pilot testing suggest that for each million units sold, the equivalent reduction in peak load is 30-50MW.[104] At the current rate of CFL sales, the impact on the peak demand is a reduction of about 400-600 MW. With a more developed market, the potential is estimated at about 2700-4500 MW in peak load reduction.

9. Energy performance labels and standards for electrical appliances

Energy performance labels and standards are common means to address end-use inefficiencies. They started being developed in Iran in 1994, with the design and approval of standards for refrigerators. In 1995, a specific Standardization and Labeling Department was created under the Energy Efficiency Office in the Ministry of Energy, and in 1996, a legal text was ratified which called for more systematic preparation and implementation of standards for energy intensive appliances.

Following that legislative support, additional measures were implemented in the field of labeling and standardization. Studies were conducted on the most energy intensive household appliances, as well as the related energy consumption patterns. National laboratories were established for the testing of labeled appliances.

As of 2004, several standards and/or labels had been established for appliances such as freezers, refrigerators, washing machines, water coolers, single-phase electro motors, irons, electrical water boilers, electrical heaters, pumps, compressors, lamps, fans and chillers).[105] According to annual monitoring and

[102] Modelling by the World Bank (March 2006) based on data gathered through discussion with Mr. Lavaee, Distribution Manager at Tavanir, and with Mr. Hasanzadeh, Director of Electrical DSM Department at Tavanir, in January 2006.
[103] Information based on discussion with Mr. Hasanzadeh, Director of Electrical DSM Department at Tavanir, on January 16, 2006.
[104] Information based on discussion with Mr. Hasanzadeh, Director of Electrical DSM Department at Tavanir, on January 16, 2006.
[105] Abdollahshirazi, A. (2004) *Energy Management Promotion in Iran*. Paper prepared for the International Summer School 2004, "Renewable Energy in Schleswig-Holstein. Regional Experience for International Development." 07-13 June 2004, University of Flensburg, Germany.

testing of the standardized appliances, it is possible to estimate the average savings per appliance per year. However, it is more difficult to monitor the total energy savings achieved since the start of the program. A recent study reports that standardization and labeling activities for freezers and refrigerators have been particularly successful, and contributed to savings of about 450 million kWh in 2002-2003.[106]

However, challenges still remain to motivate consumers to buy (often) more expensive but energy efficient appliances, as well as to increase the collaboration with manufacturers and sales points.[107]

10. Information, education, training and awareness raising activities

In parallel to specific energy efficiency projects, all stakeholders (Ministry of Energy, Energy Efficiency Organization (SABA), Iranian Fuel Conservation Organization(IFCO), Tavanir) have developed information programs and forms of awareness raising activities, in order to reinforce the benefits of energy efficiency activities. Some training courses have also been organized to create and/or improve technical expertise of people in the field of energy efficiency. The Ministry of Energy notably contributed to the training of more than 1,500 experts on energy audits and energy efficient technologies through four different courses. Informative leaflets, TV and radio ads, education programs for children, and various workshops in the industrial sector are some of most important activities implemented. [108]

[106] UN Economic and Social Commission for Asia and the Pacific (2004) *End-Use Energy Efficiency and Promotion of a Sustainable Future*. Energy Resources Development Series No. 39. United Nations, New York, USA.
[107] Information based on discussion with Mr. Hasanzadeh, Director of Electrical DSM Department at Tavanir, on January 16, 2006.
[108] Information available on the website of the Iranian Ministry of Energy at http://www.iranenergy.org.ir (March 17, 2006).

Annex 9: Recommendations for Energy Efficiency and International Experience

Loss reduction activities for transmission and distribution lines

Loss reduction activities should be considered as priority options for energy efficiency, and the pilot measures should be extended. In order to limit the budgetary implications, the program would first prioritize the areas where such measures are the most economically viable (for example where loss rates are very high, or where particularly energy intensive consumers are concentrated).

Load management activities and smart meters in the industry

Based on the smart-meters (to be) installed the introduction of pricing signals for electricity should be investigated, such as Time of Use tariff or other innovative price mechanisms for energy efficiency.

This process should be started in the short term by targeting large (mostly industrial) customers through simple mechanisms (such as load buy-back / "interruptability" schemes[109]) to be able to gain from this knowledge and expand the programs in the medium term.

An example of successful load management program (in China) is given in Box 9.A below.

Box 9.A: Peak Load Management in Beijing, China

Beijing began engaging in DSM activities primarily for load management purposes in response to rapidly escalating peak demand. The peak load grew from 3 GW in 1992 to nearly 4.5 GW in 1996, a yearly average load growth of 10.4 percent. The minimum load had increased slowly, while the daily max-min had grown quickly, decreasing the annual system load factor by around 86 percent in 1992 to 82 percent in 1996. This made it difficult for Beijing to ensure the safe, stable and economic operation of the power system. In order to promote the load factor increase, Beijing's main goal was to open up the power market in off-peak hours.

The first step was to investigate the consumer power market. Before developing effective measures for peak load management, Beijing carried out a survey to determine the condition of customers' electric equipment and consumption patterns. Models and software programs were developed, based on the load survey, to analyze the efficiency opportunities available from major customers in key industries.

The survey revealed that in 1996, industrial consumption accounted for over 55 percent of the typical winter daily electricity consumption in Beijing, including 51 percent of the system's morning peak and around 50 percent of the evening peak. Even though the industrial load is the base-load of the Beijing system, there is still a large potential for load shifting through the rational arrangement of discretionary load.

Based on the above analysis, Beijing decided upon the following measures to improve its system load

[109] Such schemes involve the setting up of incentives (and / or penalties) for participating consumers to shift their load when it coincides with peak demand. Basically the incentives are calculated based on the (avoided) costs of building a peak plant.

factor:

- Further expand the price differential between the peak and valley hour tariffs in order to encourage load shifting;
- Sign interruptible load agreements with large customers, first on a pilot basis, then on a more widespread basis;
- Encourage enterprises to rearrange their production schedules so that scheduled maintenance took place during peak hours;
- Encourage enterprises to establish schedules to upgrade and retrofit high loss electrical equipment, such as motors and transformers; install reactive power compensators for high and low voltage equipment; and arrange equipment with higher diversity factors to operate at peak hours with a minimum operating scheme and at off-peak hours with a maximum operating scheme;
- Encourage customers to use highly efficient electric devices, retrofit existing production processes in order to improve productivity, and invest in technologies that shift usage from peak to valley periods, such as ice storage air conditioning and storage electric heaters; and
- Provide financial assistance based on actual upgrading and retrofitting needs.

The net effect of these measures was a reduction in the peak demand of 50 MW in 1997, an additional 50 MW in 1998, and an improvement in the load factor because of the 150 GWh increase in consumption during the valley load period. The investment to produce the peak load shift was 12.05 million RMB in 1997 and 5.67 million RMB in 1998. The annual benefit based on the avoided cost of new generation capacity was estimated at 24.8 million RMB.

The Beijing DSM project was successful primarily because it focused on peak load management, which is generally easier to implement than other DSM programs. In many cases, load management can be accomplished with properly designed and progressive tariffs, such as time of use and interruptible tariffs. After successfully completing the load management program, Beijing has now gained practical experience that should prove useful for the development of DSM programs that result in long-term reductions in demand through efficient end use technologies. Beijing is now conducting a detailed study of DSM policy options and incentive mechanisms with the support of the Energy Foundation.

Sources:

(1) Finamore, B. et al (2003) *Demand-Side Management in China. Benefits, Barriers and Policy Recommendations*. Natural Resources Defense Council, New York, USA. Available on the China Sustainable Energy Program website at http://www.efchina.org (December 6, 2005).

(2) Hu, Z. "Benefit Analysis on Application of Demand Side Management (DSM) in Beijing." *Automation of Electric Power Systems*, Vol. 23, No. 13, July 1999.

Energy audits for energy intensive industries and development of an ESCO industry

Efforts should be pursued to use audit mechanisms and make them successful tools to promote demand side management measures in the industrial sector, for which ESCOs would be the key instrument. These efforts should be reinforced by important information campaigns and capacity building for ESCOs.

A good platform would be the development of a program (such as a public building energy efficiency program), through which ESCO could develop their hands-on expertise with audits and practical measures implementation in the industry.

An example of a successful public building energy efficiency program (in Mexico) is given in Box 9.B below.

Box 9.B: Energy Efficiency in Federal Public Buildings in Mexico

Mexico's government sector energy conservation activities began in the early 1990s and have burgeoned into perhaps the broadest government end-use program in the world, impacting hundreds of government facilities. It started in the early 1990s under the "100 Public Buildings" pilot program, which later evolved into the Program of Energy Savings in federal Buildings (or APF program), led by the National Commission for Energy Conservation (CONAE).

Even though no reliable data on energy consumption by the public sector has been gathered, Mexico's relatively large public sector, representing around 10 per cent of the country's total demand for goods and services, is considered to be a very large energy consumer. In the early 1990s, CONAE began a series of energy studies and audits in different sectors, including the public sector at the federal level. The energy studies consisted basically in an assessment of the lighting systems and equipment based on energy audits, which showed that the largest potential for energy savings was in lighting systems.

With that knowledge, CONAE launched the "100 Public Buildings". The program provided training and technical assistance to building operators to help them to perform data gathering based on CONAE designed methodologies, conduct their own assessments, and follow up on measures, including permanent monitoring of energy use, and operation & maintenance of newly installed equipment. Consequently CONAE proposed to extend the program to the entire federal government in 1998, and in 1999, all the federal agencies were mandated to participate in the Energy Savings Program, following the guidelines published in the Federal Official Gazette and establishing the program scope.

The staff representing the agencies was trained through specific workshops on guidelines, operational mechanisms and activities to be performed as part of the program.

In 1999-2000, the program concentrated on the extensive training of building operators via interactive workshops and distance-training courses. A complementary decree was enacted, that stipulated a mandatory working schedule for federal agencies in order to minimize unnecessary energy use (7:00 to 18:00). During this first stage, the participating buildings reduced their energy consumption by approximately 12%.

In 2000-2001, CONAE started providing technical workshops, as well as direct technical assistance for implementing the lighting measures. Additional specialized courses in different energy-saving technologies were also provided for qualified personnel. The guidelines were updated to require the preparation of monitoring reports from participating agencies, and to establish a goal of achieving 20% reduction in electricity consumption by end 2000, as compared to 1998 levels. By analyzing the post-retrofit data, CONAE detected that only 20% of the participating agencies had reached the stated goal, primarily as a result of the increased load due to computer equipment as well as a lack of compliance with the shortened work schedule.

Due to the previous year's results, the new guidelines for 2001-2002 established that the energy savings goals would be defined by each agency based on recommendations emitted by CONAE (and based on each agency's energy consumption index).

In only three years of operation (1999-2002), the APF program achieved impressive results in terms of electricity and cost savings. It is estimated that the energy savings reached 100 GWh, amounting to public sector savings of approximately US$ 7.4 million. The program also contributed to better cooperation among different government agencies and widespread training of personnel.

Sources:

(1) "Energy Efficiency in Federal Public Buildings in Mexico: the APF Program". Promoting an Energy Efficient Public Sector (PEPS) case study published on the PEPS webpage at http://www.pepsonline.org (December 6, 2005).

Distribution of subsidized Compact Fluorescent Lights and other energy efficient bulbs

Collaboration with the Regional Electricity Companies should be extended, so as to reach more customers with energy efficient bulbs.

Innovative financing schemes for CFLs (or other energy efficient equipment) should be investigated. For example cooperative procurement schemes could be developed, supplemented by intensive education and information campaigns both at the utility and at the consumer levels.

Box 9.C below summarizes the successful initiative developed in Egypt by the Alexandria Electricity Distribution Company for the diffusion of CFLs.

Box 9.C: Alexandria Electricity Distribution Company's DSM experience (Arab Republic of Egypt)

Alexandria is the second largest city in Egypt and accounts fo 40% of Egypt's industrial activities. AEDC has a maximum load of 1,100 MW and annual consumption of more than 5,000 million kWh.

Since their emergence on various lighting markets in the world, Compact Fluorescent Lamps (CFLs) have created a revolution in the field of energy efficient lighting. Designed as compact versions of full-sized fluorescent (commonly used in industrial facilities, schools, etc.), CFLs operate at relatively low temperatures, are highly efficient and last a long time. A CFL will last up to ten times longer than an incandescent bulb, use a quarter of the energy, produce 90% less heat and more light. The initial cost of a CFL is usually much greater than an incandescent bulb, but the energy savings generated will more than offset the initial costs. In typical applications, the energy savings will pay for the initial cost of the CFL in one year.

In 1995, when Alexandria started it collaboration with the "Energy and Urban Environment in Mediterranean Countries" (EUEMC) project, there was no CFL on the light bulb market in Egypt. The objective of the collaboration with the EUEMC project in this phase was to replace traditional light bulbs in residential areas and schools by CFL bulbs in order to demonstrate their practical use, and their impact on electricity bills.

However, and despite the successful results of the pilot demonstration, various barriers to the large-scale development of CFLs in Alexandria still inhibited consumer to buy them. The main barriers (which are in fact commonly encountered in many countries where CFLs are not used) related to affordability, information, access and risk aversion.

Following the EUEMC project, the Alexandria Electricity Distribution Company decided to address these barriers, and support the diffusion of CFLs for its customers. To do so, the company designed an innovative leasing scheme dedicated to CFLs. This scheme covered the bulk buying of CFLs directly by AEDC (thereby reducing the price for each unit), and the re-selling of the lamps to the customers, who can purchase them at specific retail locations. The leasing process is applied by selling the CFL to the customer for a down payment representing 10% of its price, the remaining amount being added to the electricity bill in equal installments over a period of 2 to 3 years. In parallel, AEDC organized a systematic distribution of information leaflets on the benefits of using CFLs instead of traditional

incandescent bulbs targeted at its consumers.

The combination of the procurement scheme, the leasing arrangement and the information campaign happened to be exactly the right instruments to overcome barriers, and foster the dissemination of the innovative efficient products that were CFLs in Egypt. This arrangement has contributed to sell more than 35,000 efficient bulbs in Alexandria, and the leasing scheme is still in place at present. Six retail locations of CFLs propose the leasing arrangement to AEDC customers, and locally manufactured CFLs have pushed the unit prices even further down.

It is worth noting that whereas the early success of the AEDC leasing mechanism for the diffusion of CFLs was recognized, it took about ten years for other EDCs to replicate it at a significant scale.

Source:

(1) The World Bank (paper in preparation on "What makes power utilities successful in driving DSM initiatives?")

The implementation of efficient lighting should be extended to other sectors (industry, public lighting, etc.), especially those with an important impact on the peak load.

Box 9.D below summarizes the development of an ESCO/street lighting program in Latvia.

Box 9.D: ESCO Efficient Street Lighting Project in Latvia

In the late 1990s, street lighting was in very poor conditions in Latvia, as illustrated by the following:

- Very energy-inefficient technology, notably because of very old existing equipment (some of the cables being used have been installed before 1940) and limited or no maintenance performed over the years.
- Due to limited financial resources, residential areas street lighting was provided for only a limited period of time during the night (no lighting between 1AM and 6AM) and by limited number of lamps (only every third lamp would be used on many streets).

In the late 1990s, many municipalities tried to address the street lighting situation and decided to develop and implement street lighting upgrades via modernization and reconstruction.

The IFC/GEF Efficient Lighting Initiative (ELI) started in 2000 and operated for three years in seven countries including Latvia. In Latvia the ELI program decided to focus on efficient street lighting programs and to investigate the opportunities for overcoming the following observed obstacles (as of 2000):

- Ownership of the street lighting fixtures unclear: only three municipalities in Latvia (including Tukums) owned their street lighting. Latvenergo (the power utility) owned the other 523 ones.
- Lack of finance: municipalities had limited opportunities to get loans, and efficient lighting was often considered as a low priority.
- Long project payback times: this was mainly because street lighting was not used either full time or fully (as explained earlier).
- Lack of positive cashflow from a project: operating revenues did not cover the full operating and maintenance costs.
- Lack of street lighting standards: European Union standards were neither translated nor used.

The project started by trying to raise municipal awareness through the use of training workshops for potential municipalities and competitions between municipalities to see which one would participate in

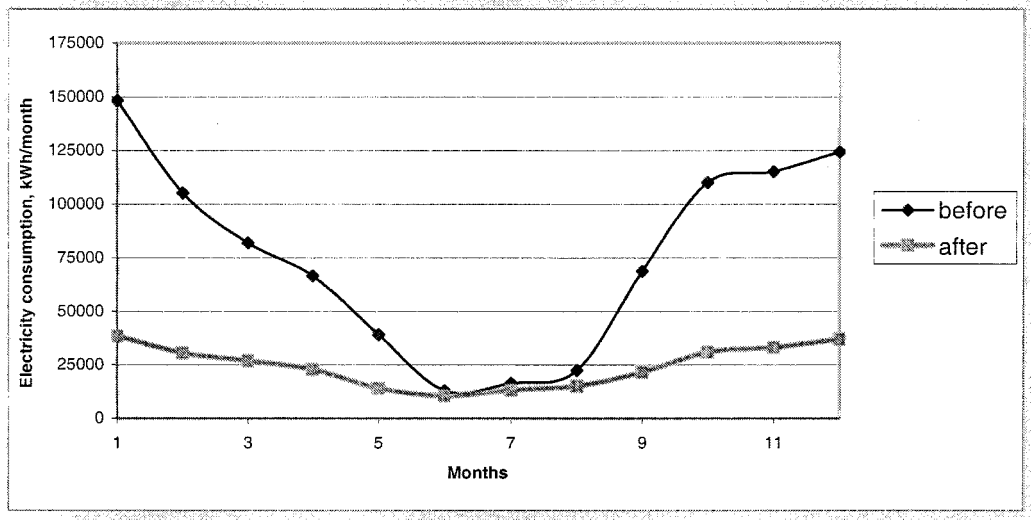
the pilot stage project. The workshops were useful for determining which municipalities appeared to be the most stable, which owned its own street lighting, which was open to participate in an ESCO, etc.

The pilot project in Tukums started in December 2001, when Ekodoma (an independent engineering consulting company) in close cooperation with specialists from the municipality carried out an energy audit of Tukums' street lighting system.

The first milestone was achieved in April 2002, when a detailed business plan was presented to the Tukums City Council. The plan included technical solutions, project profitability, specifications, O&M, financial and economical analyses and a market investigation of potential Latvian ESCOs. Following this, in June 2002 a tender addressed to ESCOs to develop an efficient street lighting system in Tukums was announced. At the end of September the Service Company selected and Tukums Council signed a contractual agreement of 10 years duration. During this period, the ESCO will develop the project and then both operate and manage it.

This pilot project in Tukums has been an important test of "performance contracting" in Latvia (it was the first project to use third party financing in Latvia) and the preparation of a contractual agreement is an important added value for other energy efficiency projects in Latvia. Along the project about 950 light bulbs were replaced by 70-100 W light bulbs, and about 2.8 km of street lighting system have been improved or (re)constructed. As a result, the total installed capacity was reduced to 89kW, and energy savings of about 630,000 kWh/year (equivalent to about US$ 41,000 per year – see Figure 2 below), along with US$ 15,000 per year saved in maintenance fees.

Energy savings in the Tukums street lighting project



Finally the project brought about some important lessons for the development of future similar initiatives in Latvia and elsewhere:

- The ESCO concept is commercially viable in Latvia. The preparation work of the ELI Latvia team included information dissemination as well as training and education of both potential ESCOs and ESCO clients.
- The first lighting ESCO pilot project has been completed in Tukums. Wesemann, a local company, is operating as ESCO. The legal aspects of performance contracting have been tested in the pilot project in Latvia and found to be workable.
- The development of the project shows the important role not only of specialists but also the role that municipal leaders play. These kinds of projects are the result of the teamwork.

- The campaign became a spotlight of public and mass media, remarkable amount of material was published and interviews were given, as well in most powerful mediums in Latvia.

Sources:

(1) "Overview of the ELI activities – Latvia", webpage of the Efficient Lighting Initiative at http://www/efficientlighting.net/latvia (December 6, 2005).

(2) Rochas, C. and Blumberga, D. (2005) *Analysis of ESCO Efficient Street Lighting Project*. Paper prepared for the 6th International Conference on Energy Efficient Lighting, 9-11 May 2005, Shangai, China.

Development of mandatory energy performance labels for electrical appliances

The expansion of the standards and labeling program to other energy intensive appliances should be considered.

Complementary measures that involve appliance distributors and retailers should also be introduced (such as information / training, financial incentives or technology procurement), so as to make the program more effective.

Finally, care must be taken to reflect changes in the market and technical progress, and to undertake activities to regularly revise energy efficiency classes on the labels

Information, education and awareness campaigns and trainings

Education, information and training programs are essential support mechanisms that should continue to be developed in the near future. They will help building up on the momentum that has been initiated for the past years. In addition, such mechanisms are substantial tools to accompany other types of mechanisms as they are tackled through new programs. For example, the involvement of the general public through large awareness campaign efforts should be an integral part of any program dealing with demand-side management. The legislative framework in place to promote renewable energy in Iran is embodied in the Fourth FYDP.

Annex 10: Electricity Prices for Various Consumer Categories in Iran

Rials/kWh

Year	Residential	Public	Agricultural	Industrial	Commercial	Total Avg.
1968	4.28	1.95	1.91	2.15	1.95	2.90
1969	3.46	1.58	1.55	1.74	1.58	2.21
1970	2.70	1.23	1.21	1.36	1.23	1.66
1971	3.00	1.37	1.34	1.51	1.37	1.82
1972	2.79	1.27	1.24	1.40	1.27	1.69
1973	2.50	1.14	1.12	1.26	1.14	1.47
1974	2.34	1.07	1.05	1.18	1.07	1.42
1975	2.57	1.17	1.15	1.29	1.17	1.53
1976	2.80	1.26	1.25	1.41	1.28	1.70
1977	3.58	1.43	1.60	1.80	1.43	2.17
1978	3.67	1.45	1.80	1.90	1.45	2.28
1979	3.10	1.93	2.45	2.00	1.93	2.34
1980	4.20	2.15	2.53	1.90	2.15	2.75
1981	4.50	1.86	2.90	1.65	1.85	2.70
1982	4.20	6.24	2.75	1.60	6.24	3.90
1983	3.90	5.44	3.24	1.70	5.44	3.50
1984	4.20	4.96	3.61	1.60	4.96	3.50
1985	4.20	5.30	3.38	1.56	5.30	3.60
1986	4.50	4.36	2.75	2.56	4.36	3.80
1987	5.23	6.68	4.64	3.60	6.68	5.20
1988	5.27	7.59	4.60	3.70	7.59	5.50
1989	5.52	6.72	4.85	3.70	6.72	5.40
1990	5.70	3.46	5.60	7.50	3.46	5.50
1991	7.00	10.33	7.10	9.36	10.33	8.50
1992	9.86	6.95	8.43	15.75	6.95	10.50
1993	11.80	13.02	10.05	18.00	13.02	13.70
1994	15.50	43.98	7.60	43.98	64.32	32.40
1995	20.45	53.12	7.83	53.05	74.05	38.82
1996	26.08	48.43	7.90	66.46	91.20	46.56
1997	31.20	65.11	8.20	83.61	96.78	55.93
1998	41.40	70.30	8.20	102.70	116.33	67.06
1999	58.32	77.95	8.78	113.00	210.00	80.30
2000	65.11	83.54	12.81	121.00	247.00	89.36
2001	72.93	99.59	11.50	133.58	273.86	98.52
2002	85.13	124.48	12.65	146.94	342.30	114.11
2003	97.00	152.00	14.00	162.90	412.00	131.76
2004	107	175.89	16.01	198.82	446.96	151.06

Annex 11: Detailed calculations for Subsidies, Contingent Liabilities

IRAN - Subsidy to gas consumption - Results highlighted in orange below

Projected capacity

	units	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Installed capacity	mw	39728	42983	46741	50697	55204	59920	64945	70385	76318	82729	89678

Capacity shares (2 scenarios)

		units	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
scenario 1	Steam turbines	% capacity	40%	38%	37%	35%	34%	33%	31%	30%	29%	28%	27%
	Large gas turbines	% capacity	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
	Combined cycle gas turbines	% capacity	20%	21%	22%	22%	23%	24%	25%	26%	27%	28%	30%
base case	Steam turbines	% capacity	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
	Large gas turbines	% capacity	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
	Combined cycle gas turbines	% capacity	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%

Gas consumption

scenario 1		units	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
	Steam turbines	bcm	23 2	24 1	25 2	26 2	27.4	28 5	29.7	30 9	32 1	33 5	34 8
	Large gas turbines	bcm	14 8	16.0	17 4	18 9	20.6	22 3	24.2	26 2	28 4	30 8	33.4
	Combined cycle gas turbines	bcm	9.9	11.1	12 6	14.2	16 1	18 2	20 5	23 1	26 1	29 4	33.1
	total	***bcm***	***47.9***	***51.3***	***55.2***	***59.3***	***64.0***	***69.0***	***74.4***	***80.2***	***86.6***	***93.6***	***101.3***

base case		units	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
	Steam turbines	bcm	23 2	25.1	27.3	29 6	32 2	35.0	37.9	41 1	44 6	48 3	52 4
	Large gas turbines	bcm	14.8	16.0	17 4	18 9	20 6	22 3	24 2	26 2	28.4	30 8	33.4
	Combined cycle gas turbines	bcm	9.9	10.7	11 7	12.6	13.8	14 9	16.2	17 6	19.0	20.6	22.4
	total	***bcm***	***47.9***	***51.8***	***56.4***	***61.1***	***66.6***	***72.3***	***78.3***	***84.9***	***92.0***	***99.8***	***108.1***

ASSUMPTIONS AND PARAMETERS			
	plant factors	heat rates	
Annual changes in capacity shares (input)		kBtu/kWh	Bcm/GWh
-4.0%	73%	8.152	0.00022826
0.0%	83%	9.15	0.0002562
4.0%	81%	6.277	0.00017576

Subsidy to gas consumption

	units	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
base case	billion Rials	18779	23873	30218	37795	47016	57757	70182	84471	100749	118982	139151
	billion USD	**2.1**	**2.3**	**2.6**	**2.9**	**3.2**	**3.6**	**4.0**	**4.5**	**5.0**	**5.5**	**6.1**
scenario 1	billion Rials	18779	23608	29581	36662	45239	55182	66652	79825	94839	111686	130392
	bilion USD	**2.1**	**2.3**	**2.5**	**2.8**	**3.1**	**3.5**	**3.8**	**4.2**	**4.7**	**5.2**	**5.7**

	units	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
inflation Iran	-		17.0%	16.0%	15.0%	14.0%	13.0%	12.0%	11.0%	10.0%	9.0%	8.0%
inflation USA	-		2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
exchange rate	Rials / USD	9000	10273	11626	13044	14508	15994	17476	18925	20310	21598	22757

production cost of gas	Rials / m3	420	491	570	656	747	844	946	1050	1155	1259	1359
current price of gas	Rials / m3	28	31	34	37	41	45	50	55	60	66	73

CASE 1 - GAS PRICE INCREASES WITH INFLATION

Subsidy to gas consumption

	units	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	TOTAL
base case	billion Rials	18779	23771	29986	37402	46429	56947	69129	83161	99188	117197	137204	
	billion USD	**2.1**	**2.3**	**2.6**	**2.9**	**3.2**	**3.6**	**4.0**	**4.4**	**4.9**	**5.4**	**6.0**	**41.3**
scenario 1	billion Rials	18779	23508	29353	36281	44673	54408	65651	78588	93369	110011	128567	
	bilion USD	**2.1**	**2.3**	**2.5**	**2.8**	**3.1**	**3.4**	**3.8**	**4.2**	**4.6**	**5.1**	**5.6**	**39.4**

CASE 2 - GAS PRICE GROWS AT 10% PER ANNUM

Subsidy to gas consumption

	units	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	TOTAL
base case	billion Rials	18779	23873	30218	37795	47016	57757	70182	84471	100749	118982	139151	
	billion USD	**2.1**	**2.3**	**2.6**	**2.9**	**3.2**	**3.6**	**4.0**	**4.5**	**5.0**	**5.5**	**6.1**	**41.8**
scenario 1	billion Rials	18779	23608	29581	36662	45239	55182	66652	79825	94839	111686	130392	
	bilion USD	**2.1**	**2.3**	**2.5**	**2.8**	**3.1**	**3.5**	**3.8**	**4.2**	**4.7**	**5.2**	**5.7**	**39.9**

Project Name	Sponsor	Size at ISO	Annual production	Annual gas consumption	Annual value of gas	Annual subsidy for gas	Status	Annual liability	
BOO		*MW*	*GWh*	*bcm*	*billion Rials*	*billion Rials*		USD million	USD billion
Rood'e shoor	Arian Mahtab Gostar	2112					Under construction		
Mashhad (Toos Development)	Mapna	954					Under construction		
Zanjan 4	Bank Melli Investment	544					ECA is signed		
Gheshm Island	Hirbodan	160					ECA is signed		
Hormozgan		500					ECA is signed		
Assalluyeh	Bonyad Mostazafan va Janbazan	500					No ECA yet		
Zanjan 3	Sanat Energy Tamin	500					No ECA yet		
Assalluyeh 2	Mapna	942					No ECA yet		
Semnan	Sarmayeh Gozari Tamin Ejtemaii	500					No ECA yet		
Ali Abad	Mapna	950					No ECA yet		
Sub total		**7662**	**45973**	**11.8**	**329.8**	**4617.1**		**689.6**	**0.7**
BOT									
South Isfahan	Mapna International, Iran Foreign Investment Company Holding AG (IHAG)	734					Operational		
Pareh Sar	Gruppo Falck, Mapna International, DSD Steel Group GmbH	900					Shareholders chaning		
Tabriz	Xenel	1000					Ready for ECA signing		
Fars	Mapna International, Quest Energy Middle East Ltd.	735					ECA is signed		
Ali Abad	Saudi Oger Ltd, International Power plc, Sojitz Corporation	863					ECA under negotiation		
Genaveh	TBD	500					To be bid		
Sub total		**4732**	**29194**	**7.5**	**209.4**	**2932.0**		**437.9**	**0.4**
TOTAL		**12394**	**75167**	**19.3**	**539.2**	**7549.1**		**1127.5**	**1.1**

Assumptions and parameter		
gas consumption	bcm / GWh	0.0003
heat rate	kBtu/kWh	9.15
plant factor	%	83
Gas price	Rials / m3	28
Gas reference price	Rials / m3	420

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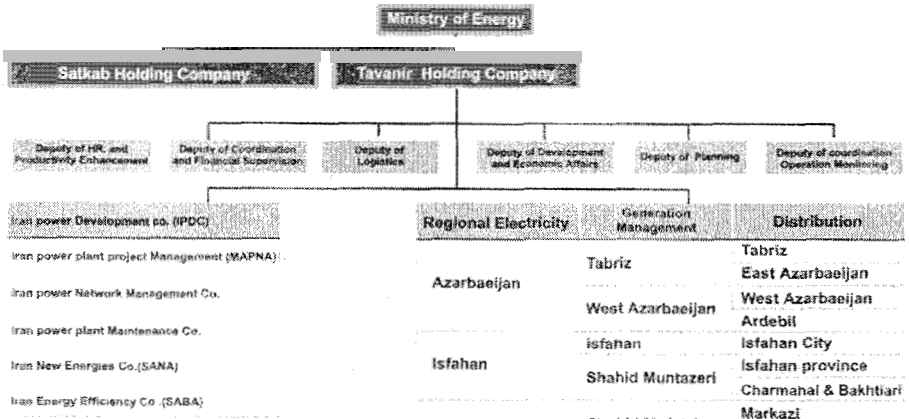
Annex 12: Organization of the Electricity Sector



Regional Electricity	Generation Management	Distribution
Azarbaeijan	Tabriz	Tabriz
		East Azarbaeijan
	West Azarbaeijan	West Azarbaeijan
		Ardebil
Isfahan	Isfahan	Isfahan City
	Shahid Muntazeri	Isfahan province
		Charmahal & Bakhtiari
Bakhtar	Shahid Mufateh	Markazi
		Hamedan
	Shazand	Lorestan
Tehran	Rey	Central Tehran
	Shahid Muntazer Ghaem	North-west of Tehran
	Qom	North-east of Tehran
	Besat	South-west of Tehran
	Shahid rajaee	South-east of Tehran
	Shahid firouzi power plant	West of Tehran
	Damavand	Qom
Khorassan	Toos	Khorassan
	Mashad	Mashad
		South Khorassan
	Khorassan Gas	North Khorassan
Khuzestan	Shahid madhaj	Ahwaz
	Ahwaz (Ramin)	
	Shahid Abbaspour	Khuzistan
	Dez	Khohgilooye & buyer ahmad
	Abadan	
Zanjan		Zanjan
		Ghazvin
Semnan		Semnan
Systan & Baluchistan	Iranshar	
Gharb	Bistoon	Kermanshah
		Kurdistan
		Ilam
Fars	Fars	Shiraz
		Fars
	South of Fars	Bushehr
Kerman	Kerman	North of kerman
	Zarand	South of kerman
Gilan	Gilan	Gilan
	Shahid Beheshti	
Mazandaran	Shahid Salimi	Mazandaran
		West of Mazandaran
		Golestan
Hormozgan	Hormozgan	Hormozgan
Yazd	Yazd	Yazd

Source: Tavanir

Annex 13: Comparing Scheduling Regimes and Pool Pricing in Spain and Scandinavia

Comparing Scheduling Regimes in Spain and Scandinavia

There are two main methods for coordinating generators in order to meet energy demand during the day: central scheduling and self scheduling.

Under central scheduling, power is traded through a compulsory day-ahead market which serves to co-ordinate production for the following day. The SO determines each generator's entire production for the following the day and sets price using a central algorithm, usually at the System Marginal Price, i.e. the price of the most expensive generator that meets demand when placing generating units in ascending price order. The SO must have good scheduling skills in order to operate the market efficiently. Generators need only submit plant data and follow instructions. For example, in Spain, the day-ahead market is also centrally scheduled, by the market operator OMEL but as the bids are relatively simple (in most cases) the central algorithm is very simple. OMEL matches generation and demand to give a "theoretical" day-ahead schedule. The SO reviews this and advises alterations to the schedule to make it feasible. Together, the market operator (MO) and SO produce a feasible schedule and the ex ante hourly market prices for next day. Generators can then adjust their positions by trading in the voluntary intra-day markets.

Under self scheduling, there is no compulsory day-ahead market for energy trading. Generators and suppliers contract with each other, and generators schedule the production levels of their plant in order to meet their contracts. Such contracts may include obligations arising from voluntary power exchanges. The SO's role is limited to small changes to generation schedules in order to ensure system stability or meet transmission constraints using ancillary services or a balancing market. Prices are set by the bilateral trades, which could be between generators and suppliers, or with traders. In order to work efficiently, the market must be transparent, with accurate rules, and good liquidity. For example, NordPool uses self-scheduling, but any trades across transmission zones must take place through the day-ahead market.

Comparing "Pool Pricing" Regimes in Spain and Scandinavia

There are two approaches for the pricing of energy in a wholesale market: either (i) a single price across the market, or (ii) multiple prices for different zones, or even different nodes. Where there is a single price, the market is treated as one energy hub, with the SO managing congestion through the use of constrained on, and sometimes constrained off, payments (or counter-trades). Transmission charges give signals for locating new generation capacity. In Spain, there is a single energy price. The SO undertakes counter-trades to relieve transmission constraints.

Where there are multiple prices, the market is divided into several transmission zones or hubs, with a price for each zone (and this can be extended to a price for each node). Congestion is market managed, with higher prices in the import constrained zone, and lower prices in the export constrained zone. These prices balance supply and demand in each zone, allowing maximum flow across the constrained lines. These different prices provide locational signals for new generation. In NordPool, zonal prices are calculated when transmission constraints bind. The market operator looks at the theoretical flows that would occur under supply and demand bids, and if transmission constraints bind, zones are created with corresponding prices.

A "capacity fee" is defined as the difference between the system price and the zonal price. In the surplus area, the capacity fee is debited to the sellers and credited to the buyers. In the deficit area, the capacity fee is credited to the sellers and debited to the buyers.