MEE / NREA **World Bank/Danida**

DEVELOPMENT OF A COMMERCIAL WIND FARM MARKET IN EGYPT

Economic Analysis and Regulatory Options

Egypt

June 2003

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Wolfgang Mostert Associates

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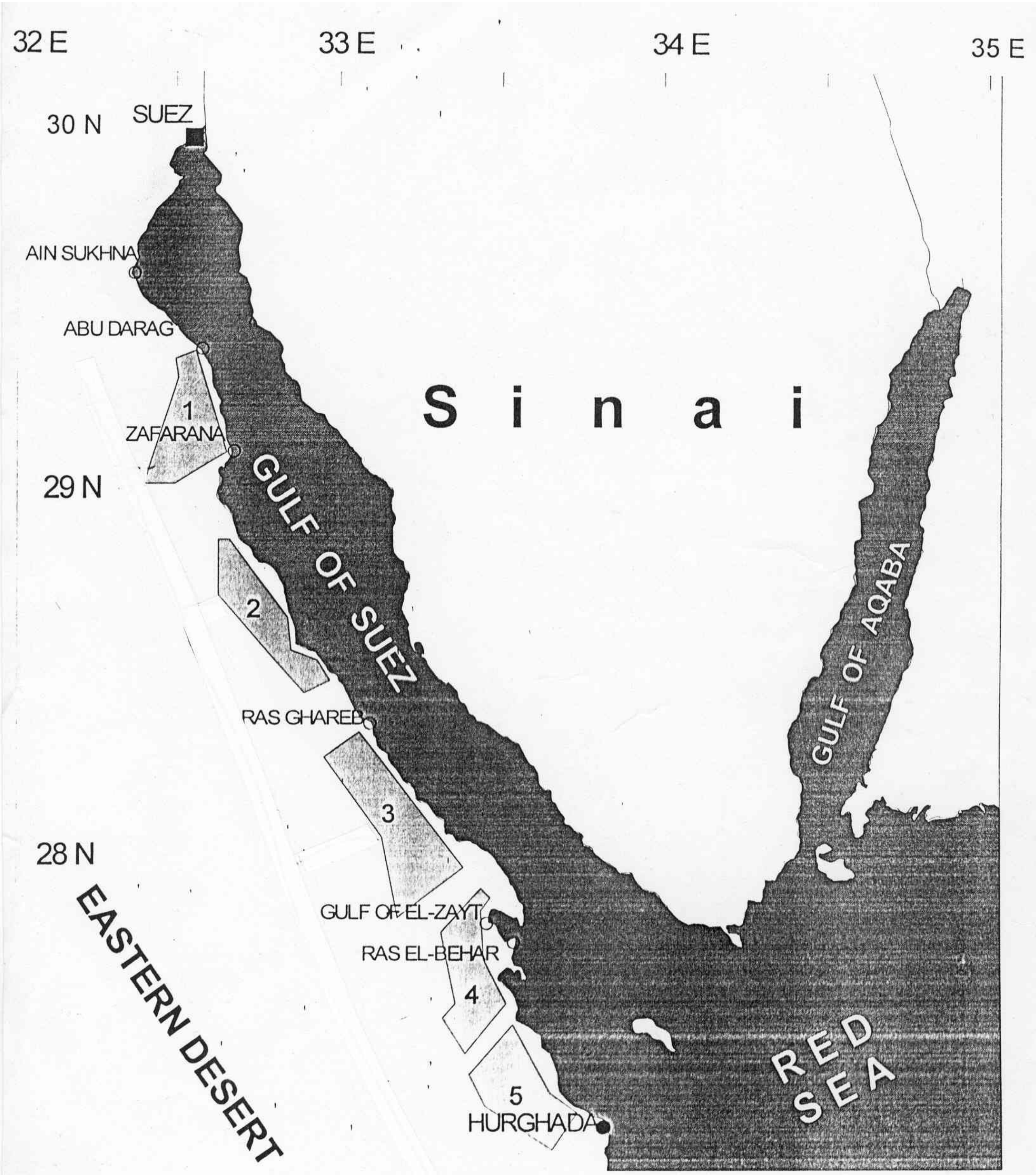

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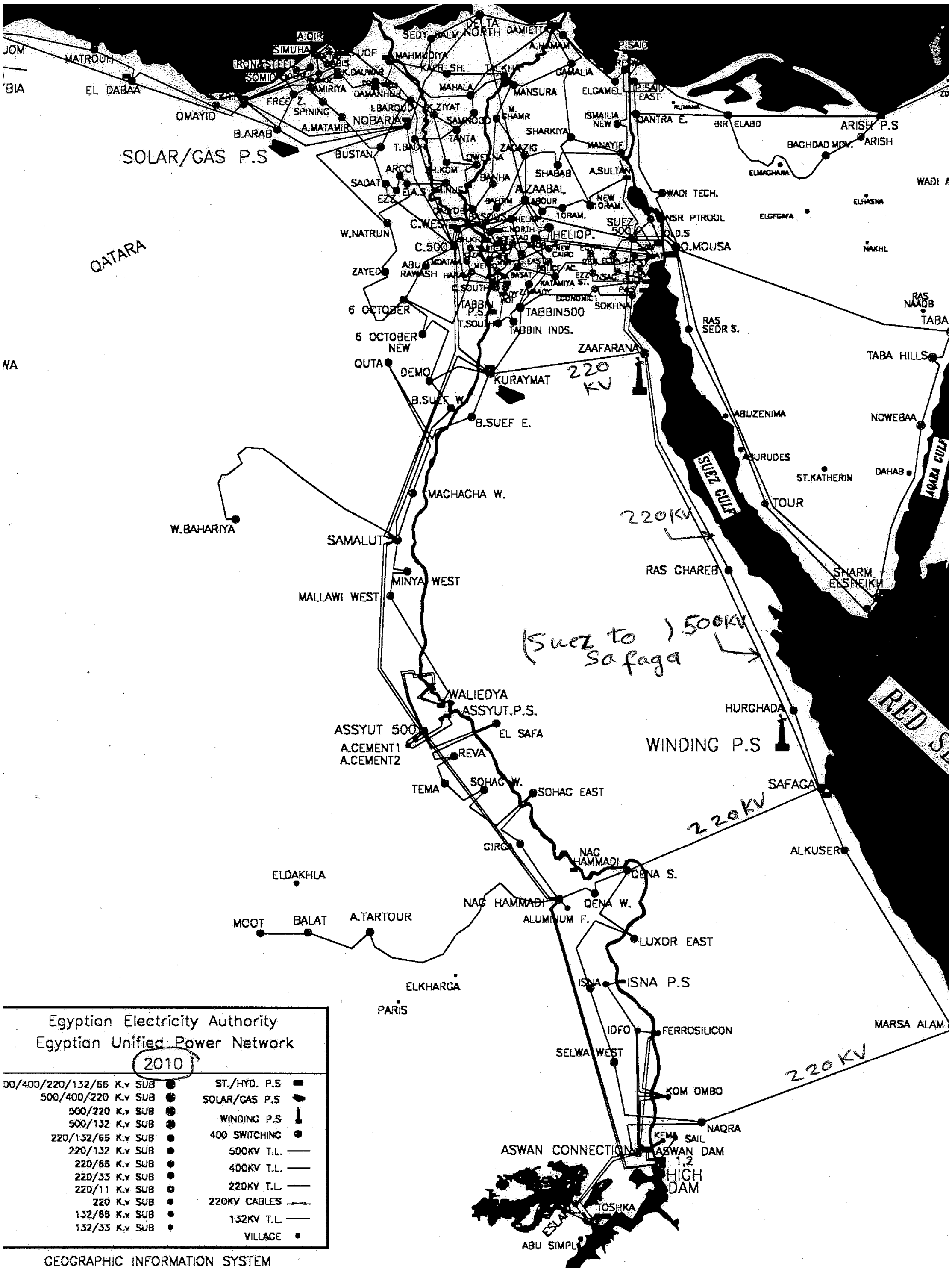


Abbreviations, Acronyms, Definitions and Conversion Factors

Abbreviations and Acronyms

ACR	Annual Charge Rate
BOO	Build, own.operate
BOOT	Build-own-operate-transfer
CCGT	Combined cycle gas turbine
CDM	Clean Development Mechanism
CER	Certified Emission Reduction (for CDM projects)
DAC	Development Aid Committee
Danida	Danish International Development Assistance
DSCR	Debt Service Coverage Ration
EEAA	Egyptian Environment Agency
EEHC	Egyptian Electricity Holding Company
EGAS	Egyptian Gas Company
EIRR	Economic Internal Rate of Return
ERA	Electricity Regulatory Authority
ERU	Emission Reduction Unit
FIRR	Financial Internal Rate of Return
GASCO	Egyptian Gas Transmission Company
GDP	Gross Domestic Product
GEF	Global Environmental Fund
GHG	Green House Gas
JIP	Joint Implementation Project
IEA	International Development Agency
IPP:	Independent Power Producer
ISO	Independent System Operator
KfW	Kreditanstalt für Wiederaufbau
LRMC	Long Run Marginal Costs
MEE	Ministry of Electricity and Energy
MOP	Ministry of Oil and Petroleum
NPV	Net Present Value
NREA	New and Renewable Energy Authority
ODA	Official Development Assistance
PCF	Prototype Carbon Fund
PPA :	Purchasing Power Agreement
Price (fob):	Price "free on board" (at the port of export)
Price (cif):	Price "cost, insurance, freight". (at port of entry).
RE	Renewable Energy
RORE	Rate of Return on Equity
SEA	Strategic Environmental Assessment
TA	Technical Assistance
TGC	Tradable Green Certificate
WT	Wind Turbine

Definitions derived from the specific Methodology used in this Report

Economic Cost of Production	Investment costs and O&M costs expressed in factor prices not including costs of externalities and discounted at the economic discount rate of 10%.
Economic Cost of Windenergy	Economic cost per kWh of wind farm investment and O&M minus the revenue per kWh from sales of generated CERs.
Financial Cost of Production	Investment costs and O&M costs expressed in market prices and discounted at the financial discount rate of 10%.
Investor Cost of Production	Annual O&M costs and tax payments expressed in market prices + inflation-depreciated / devaluation-appreciated cost of annual debt repayments & payments on interest + annual net cash flows sufficient to provide investor with the target after-tax- ROR on invested equity; all discounted at the financial discount rate of 10%.
Cost of capital barrier	Difference between the *investor's cost of production* and the *financial cost of production* caused by the absence of "tailor made" financing packages, which increase the initial cash-flow requirement, and thus, the tariff needed by a private investor.
Financial cost barrier	Price distortions on the *national energy market* that cause the gap between the financial cost of production and the market value of windenergy to be larger than the difference between the economic costs and benefits.

Definition of Terms – General Definitions

Annual Charge Rate	Annual amortization payment in % of investment of $1 at the chosen discount rate and amortization period.
Average load, MW	Total produced energy (MWh) divided by 8760.
Capacity factor	Average load (MW) as percentage of plant capacity (MW) (= generated MWh during a year divided by MW capacity* 8765).
Debt Service Coverage Ratio	Annual operating profit divided by annual amortization payments (interest + repayment on debt)
Differential rent:	Income derived from the exploitation of least-cost resources in comparison with the income from the exploitation of the marginal resources that under market prices are just able to cover the cost of production.

Load carrying capability	Replaced investment in MW of thermal power capacity as percentage of the rated maximum power of the wind farm in MW.
Load factor	Average load (kW) as percentage of peak load (kW).
Netback Value	The net revenue for a commodity at an upstream point (e.g. piped NG to the liquefaction plant), which is left, after deducting from the market price of a commodity at a specific downstream point in the value chain (e.g. price cif of LNG from Egypt landed in a European port) the price paid to the individual intervening elements of the value chain (e.g. LNG sea transport and liquefaction of NG).
Non-recourse lending	Recourse for debt repayment, default or both belongs exclusively to the project company (cash flow is "collateral")
Power System Losses	Difference between the gross production of electricity fed into the grid by the connected power plants and the measured consumption of electricity at final consumer level (8% in a very efficient system).
Resource Rent	Difference between the market price of a natural resource commodity and the economic cost of producing it.
Strategic Environmental Assessment	The formal, systematic and comprehensive process of evaluating the effects of a proposed policy, plan or program or its alternatives, including the written report on the findings of that evaluation, and using the findings in publicly accountable decision making.
Subsidy (of a product)	A product which is priced below its economic cost.
Underwrite:	An arrangement under which a financial house agrees to buy a certain agreed amount of securities of a new issue on a given date and at a given price, thereby assuring the issuer the full proceeds of the financing.

Conversion Factors

Exchange rate (april 2003)	1US$ = 5.6 EGP
1 TOE	39.69 MBTU
1 ton of natural gas	1.111 TOE
1 ton of natural gas	1272 cubic meters of natural gas
1 cubic meter of natural gas	0.0346663 MBTU
1 ton of natural gas	2.6115 ton CO_2

INTRODUCTION

Egypt has at the Gulf of Suez some of the best wind resources in the world, comparable to the best sites at the Atlantic Coast of the U.K. NREA has invested valuable efforts in acquiring wind energy know-how and setting up pilot and demonstration windfarms with financial and technical assistance from donors. Official policy for the first 600 MW of national windfarm capacity is to let NREA install and own the first 300 MW, while the private sector is to invest in the other 300 MW.

NREA is on the way to reach its target with more than 100 MW being installed at Zafarana, financed by German (KfW) and Danish (Mixed Credits) funds; while a similar number of MW financed by Spanish aid and Japanese funds is an advanced stage of negotiation. But so far, no action has been taken to involve the private sector in the financing of windfarms, although KfW / NREA in their latest tender for windfarm capacity decided to let the O&M part of the windfarm be taken care of by a private operator under contract with NREA.

The national objectives for renewable energy policy put strong emphasis on the economic cost-effectiveness of chosen technologies, which results in a shape for the “renewable energy policy-diamond” in Egypt, which is different from that found than in leading wind-energy countries.

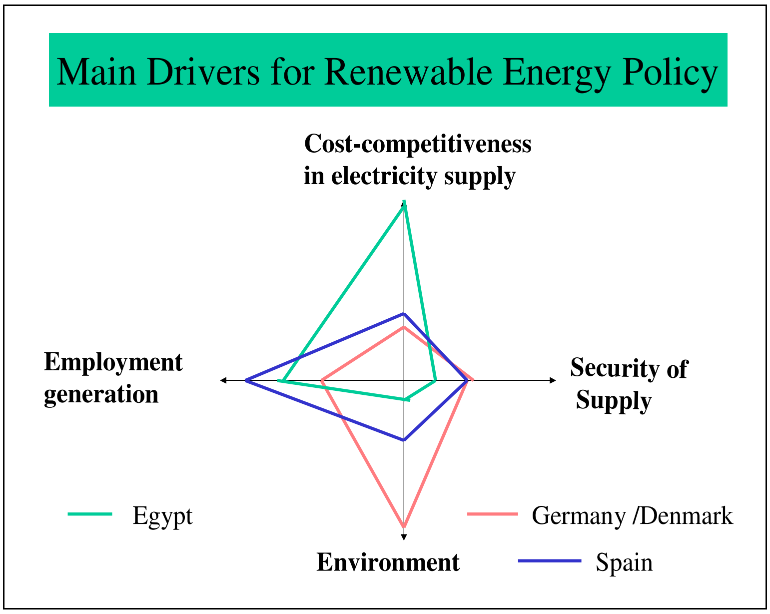


Figure 1: Policy Drivers for Renewable Energy

Windfarm development in Denmark and Germany is driven mainly by environmental objectives, in particular by the contribution of wind-energy to the national CO_2-reduction targets. In Spain, wind energy receives strong impetus from regional development objectives: regions with rich wind resources give financial incentives to wind farm developers who use technologies with a high share of local manufacturing. Employment generation is an important objective also in Egypt; yet, above all, policy makers emphasize that renewable energy generators must be cost-competitive on the bulk power market if they are to be promoted. Windenergy is at present not competitive with thermal power on the Egyptian power market.

Yet; the cost of production of new windfarm technology falls each year. The technology of new thermal power plants is also subject to continued productivity improvements, yet the rate of cost reductions during the next 10-15 years is expected to be slower than for windenergy. At one point in time in the future, wind energy will become economically viable in Egypt. The objective for Egyptian renewable energy policy is to develop the proper framework conditions for enabling windenergy to gain its economic market share in the Egyptian power market. NREA has a strong lead and implementing function during the non-commercial phase; in the future commercial phase there is no objective reason to maintain the monopoly position for NREA as windfarm investor.

The initiation of this report, outlining a market scheme for private investments in wind energy, resulted from discussions at the “Donors' Roundtable Meeting on Private Sector Wind Energy Development”, held in Cairo on June 28, 2001, which recommended the report to be undertaken.

The report attempts to answer four questions of relevance for a private sector initiative:

1. Based on realistic forecasts for productivity improvements for windfarms and for thermal power, from which future year onwards does wind energy represent an economically competitive energy technology in Egypt?

2. Does it makes economic sense to launch a commercial windfarm investment program in Egypt, using subsidies, before the year when wind energy is an economically viable option?

3. How could a partnership program between donors (GEF, World Bank, KfW, Danida Mixed Credits, Spanish Soft Loans) and the Egyptian Government be designed?

4. What kind of *market scheme* for the promotion of wind energy should be introduced for the “non-commercial period” and later for the “commercial phase”? What regulatory and institutional PPP-framework should be put in place to implement the scheme?

The TOR for the report were prepared by Richard Spencer, World Bank, assisted by Christian Sørensen, Danida, and agreed to by MEE/NREA. The TOR ask the consultant to produce

(i) an economic analysis of a private sector wind development program in Egypt,
(ii) to outline a market scheme for private wind farms in Egypt;
(iii) assist with inputs to a project concept to a wind farm development program for consideration by World Bank Management/GEF and the Government of Egypt, and
(iv) provide inputs to Danida ESPS-TA in wind farm development.

MEE/NREA is recipient of the report, which was financed by Danida. Mr. Spencer and Mr. Sørensen assisted MEE/NREA in the peer-review. KfW is interested party taking active part in discussions.

The report represents the point of view of the consultants, Wolfgang Mostert (Wolfgang Mostert Associates), Torben Brabo (Ramboll) and Prof. Adel Khalil (Cairo University).

The conclusions and recommendations need not reflect the views of the recipients.

The report is divided into nine chapters, each covering a specific theme. This facilitates the communication of the report's finding to parties who are interested in a specific them only.

- Chapters 1 and 3 cover the present and future cost of windfarm production in Egypt, in the short and long term, and provide an answer to the essential question on when windfarms will be an economically competitive generation option. Together with Annex III (index for increase in productivity of future windfarms) it can be used by those who want to check the realism of the estimates for the present and future costs of production.
- Chapter 2 estimates the benefits of windfarm production for the national power system: the value of the avoided costs of thermal power. This chapter could serve as a first basis for the discussions between NREA, EEHC and ERA on how to calculate the avoided cost tariff.
- Chapter 4 on the macro-impacts of windfarms provides information to policy makers who are interested in knowing how much windenergy can contribute in terms of security of supply in power generation and in terms of non-energy benefits such as employment generation, foreign exchange, and state revenue impacts.
- Chapter 5 on energy pricing barriers to investments in windfarms argues for changes in pricing policy to improve the situation of windfarms and national resource allocation.
- Chapter 6 on capital market barriers proposed a new financing framework for windfarms, which comprises the introduction of new financing instruments on the national capital market, changes in the terms of soft-credit finance, and recourse to the CDM-instrument.
- Chapter 7 on market schemes for windenergy provides the theoretical underpinning for the practical proposals for the institutional and regulatory framework, which is presented in chapter 8.
- Chapter 9, finally, shortly outlines an implementation strategy for the realization of the 3500 MW windfarm program, which is recommended in this report.

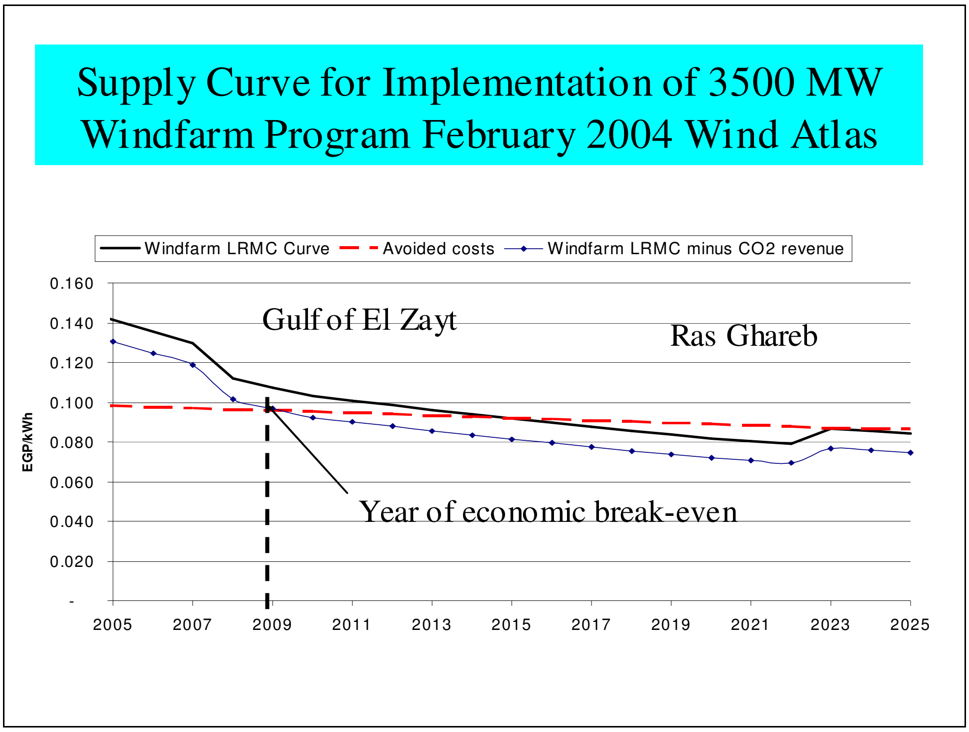
SUMMARY OF CONCLUSIONS AND OF RECOMMENDATIONS

Does Windenergy have an Economic Future in Egypt?

Year of economic break-even

Egypt has a rich wind-resource potential. Yet, at present, the cost-benefit ratio of windfarms for the national economy is negative. The economic cost of production of a windfarm established at the Zafarana site in 2004 is about 14.8 piaster/kWh. Getting the windfarm approved as a CDM-project, and assuming a price of US$4 per ton CO2, gives a revenue of 1.1 piaster/kWh from sales of Certified Emission Reductions (CERs) - the year 2004 steam turbine plants emit 0.50 kg CO_2 per kWh on average. But, the net price of electricity production of 13.7 piaster/kWh is still higher than the economic value of saved costs in replaced thermal power production, which in this report is calculated at 9.9 piaster/kWh. For Egyptian society, present investments in windfarms make economic sense only due to the 35% grant element in the soft loans to windfarms given by donors.

Technical progress in windfarm technology, however, outpaces the productivity improvements in thermal power production, see the chart below. The cost of production for a new windfarm at the Zafarana site is expected to be reduced to 8.8 piaster/kWh (-41%) by the year 2024.



The first year of economic break-even – when there is balance between the economic costs and benefits of new windfarms – is in 2009, helped by the coming on stream of the low-cost Gulf el

Zayt windfarm site in 2008. From the year 2014 onwards windfarms are economically viable also without CER-revenues.

The exhaustion of the most economic windfarm potential at the Gulf el Sayt site from around 2023 leads to the development of sites with less-favourable wind conditions, a factor which cancels out the continued productivity gains of windenergy technology. This is shown in the upward jump of the cost curve in year 2023, which shows the price conditions for windfarms at Ras Ghareb.

Macro-Benefits of a 3500 MW windfarm program in Egypt

The development allows windfarms to become an economically competitive source of power generation for 5-10 percent of national power supply. The economically viable windfarm potential at the Gulf of Suez region is 3500-5000 MW.

Macro-impacts of a 3500 MW windfarm investment program by the year 2004 include:

- An *employment impact* of 30,000 man-years for the lifecycle of the program.
- An annual *power production* of 13 TWh of wind-generated electricity, amounting to 5% of national bulk electricity supply in 2024.
- The installed capacity of 3500 MW represents 7% of installed generating capacity, *saving 1000 MW of investment in thermal power plant.*
- Savings in *annual gas consumption of 3 billion m3*, which, exported as LNG, provide a netback value to Egypt of US$160 million per year in 2024.
- *Annual lease revenue to the public budget from the lease of windfarm land,* which in 2024 amounts to EFP23 million (US$4 million).
- The *foreign exchange impact of the windfarm program is positive*. The life-cycle foreign exchange saving is 1.6 piaster/kWh for a windfarm established in year 2004; and 5.0 piaster/kWh for a windfarm set up in year 2024.

Financing and Pricing Barriers for Private Investments in Windfarms

The exploitation of the economic potential for windfarms requires the removal of energy pricing and capital market barriers, which make a private investor's cost of production prohibitively expensive, and the financial value of the avoided costs in thermal power artificially cheap.

The net result, as shown in the chart below is a huge "financial cost-benefit gap". Subsidized gas prices reduce the financial value of saved thermal power production, while the import duty and sales tax on windfarm components artificially increase the cost of windfarm output. The absence of internationally competitive terms for long-term finance represents a still more serious obstacle. The best financing conditions a private investor investing in a windfarm at the Zafarana site in 2004 would be able to get are: a capital structure of 70%/30% debt-equity, an 8 year bank loan at a 13% rate of interest, a 20-25% after tax rate of return on equity (RORE) expectation. This results in a minimum PPA-tariff requirement of 27.6 piaster/kWh, which is 17.7 piaster/kWh above the economic value of the avoided cost savings and 19.4 piaster/kWh higher than the financial value of the cost savings for the "single buyer" in the national power system.

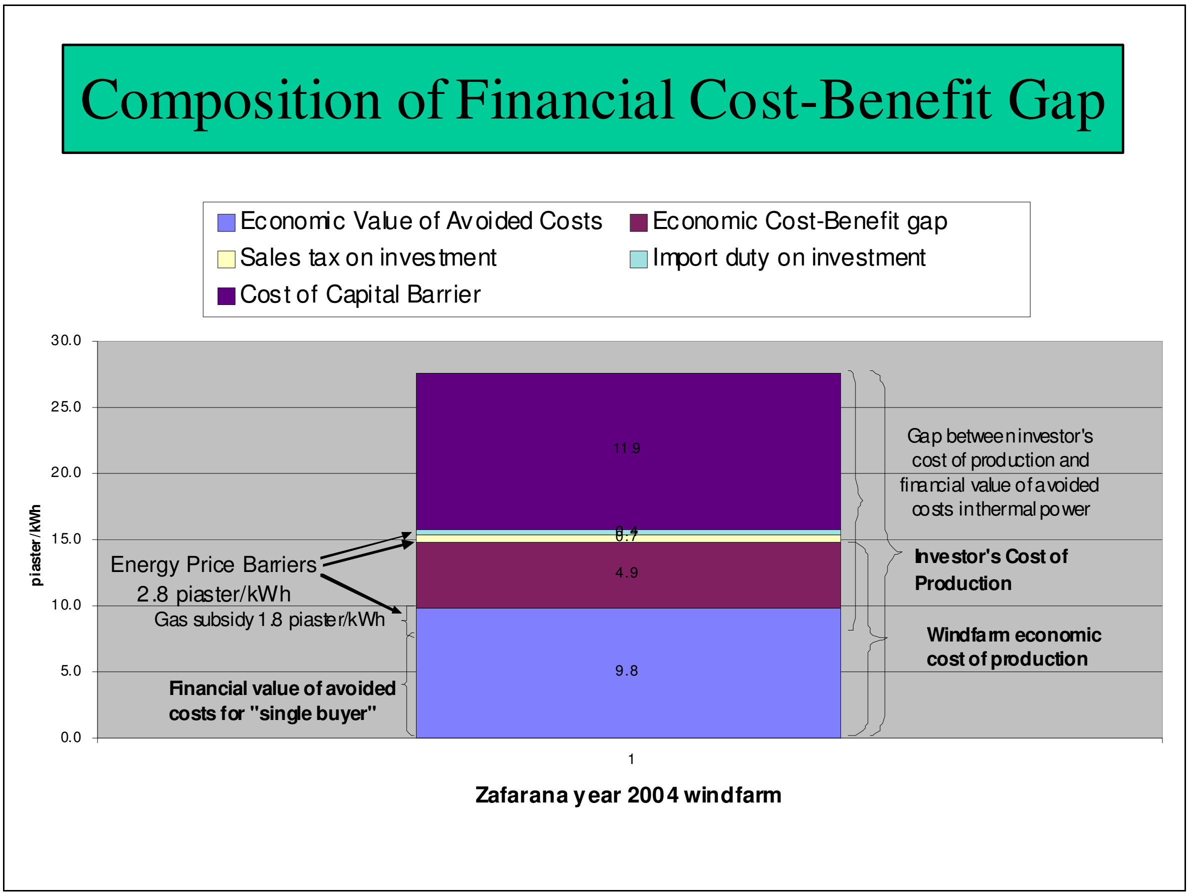


Figure 2: Composition of the Financial Cost-Benefit Gap

New Framework for Private Investments in Windfarms

Reforms are needed in five areas to enable private investments in windfarms:

(i) The 35% grant portion in the soft loans from donors is essential to reduce the economic-cost benefit gap during the non-economic period. But to assist the development of the new financing framework, donors must be able to offer their *soft credits* in the form of one-year loans, which by commissioning are repaid by long-term finance raised on the national capital market. The foreign exchange risk of having the cost of amortization fixed in foreign currency and the PPA in national currency is too high.

(ii) New *financing instruments* must be introduced, capable of lowering the cost of capital on the domestic capital market. It is recommended to test the introduction of 15-20 year revenue bonds and 15-20 year windfarm ownership certificates.

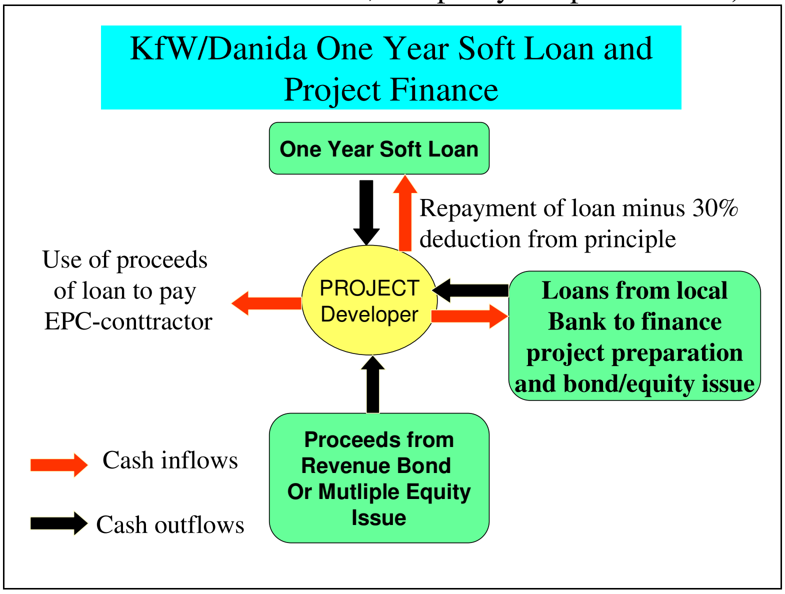
(iii) *Regulations* must fix procedures for setting tariffs in windfarm PPAs and for the tendering of leases for state owed land at windfarm sites. The PPA –tariff for windfarms should reflect the *true economic cost of saved gas consumption*.

(iv) The *import duty and sales tax* on windfarm components must be waived.

(v) New windprojects should be developed as *CDM-projects* to tap CER-revenue.

Interaction between short soft loans and long-term domestic finance

The role of soft loans in the new scheme is to channel a roughly 30% investment subsidy to the investor, and to reduce the risk of domestic long-term finance, since it is raised first at commissioning (elimination of construction risk, and partly of operation risk).



Tenders for private investments during "non-economic" phase

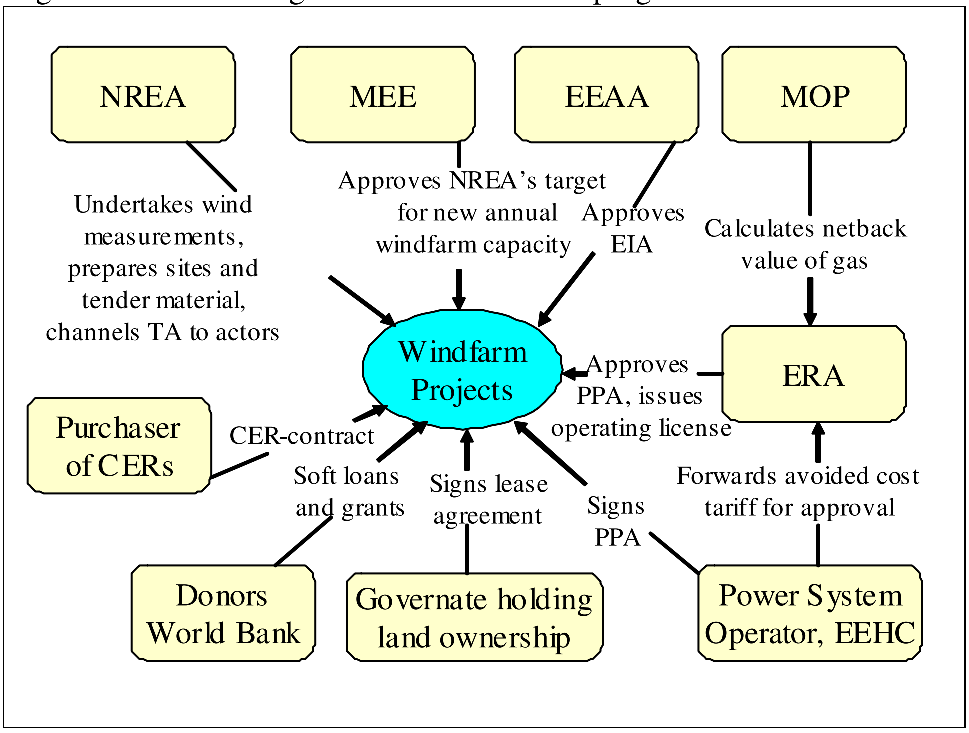
The windfarm sites would be awarded to investors through tenders for the highest bid for the lease of land. The scheme is summarised in the table below.

Market Scheme: Non-Commercial Phase II

Terms of Tender Package:	Deals concluded by Investor
1. Fixed avoided-cost PPA-tariff 2. One-Year Soft Loan from "host-donor country" for winning EPC-contractor with approximately 30% deduction from principal for end-of-year repayment. Scope of EPC-contract covered by loan declines over time. 3. Bidding for highest price for long term lease of land at tendered windfarm site	1. Identifying and negotiating best EPC-contract 2. Negotiating sales price of CO_2-certificates (CER) 3. Terms and conditions of domestic financing package to repay 1-year soft loan

Institutional division of responsibilities

The proposed institutional framework for the investments in windfarm is summarised in the table below, outlining the roles of nine agents in the investment program.



Donor-Government Partnership Program for Windenergy

The implementation of the windfarm investment program during the "non-economic period" depends on the willingness or ability of bilateral *donors* to introduce 1-year soft loans and that *World Bank/GEF* can fund "topping-up" investment subsidies during the initial years, when the grant element of the soft loans is insufficient for commerciality, as well required TA to develop the reform components. A GEF funded TA-package could comprise:

- TA to NREA/MEE in formulating the policy and action plan for the windfarm program.
- TA to NREA/MEE/ERA in developing the rules and regulations for tender procedures during the "non-economic period" and the later "fully commercial period".
- TA to ERA in developing the formula for the avoided cost tariff.
- TA, on a cost-shared basis, to the national financial sector in developing revenue bonds and ownership certificates issues, including the implementation of marketing campaigns for selling the issues to the general public
- TA, on a cost-shared basis, to potential project developers in how to enter the business.
- TA to EEHC in dealing with the integration in the national power system of intermittent power supply from 3500 MW of windfarms; in developing dispatching rules, in establishing appropriate cost-based pricing of services for interconnection.
- TA to NREA/MEE in defining rules and instruments for the maximisation of national economic benefits from the windfarm investment program.

1 STATIC SUPPLY CURVE FOR WINDENERGY, YEAR 2004

1.1 Ranking of Project Sites for a 3500 MW Investment Program

Cost effectiveness being the major political concern in Egypt, a future market scheme must promote that the best wind farm sites are developed first. These are the sites having the *best wind potential* and *requiring the lowest investments in transmission* to connect to the national grid. The best sites for a potential 3500 MW windfarm program in Egypt are located along the Gulf of Suez[1]. The eight best sites, identified in the Wind Atlas for the Gulf of Suez prepared for NREA by Risoe, are listed in the table below, their location is shown on the map on page four.

Table 1: Windfarm Sites at the Gulf of Suez. Economic Cost of Production, Year 2004 Technology

	Wind speed at 24.5 m	Annual MWh per MW	Capacity factor	Total MW-Potential	Economic Cost of Production, 2004 Piaster per kWh[1)]
Zafarana	9	3,942	45%	320	14.8
Gulf of El Zayt 1	10	4,380	50%	960	13.3
Ras Ghareb	9	3,942	45%	320	14.8
Ras Suker	9	3,942	45%	160	14.8
Gulf of El Zayt 2	9	3,942	45%	160	14.8
Sant Paul	8	3,504	40%	480	16.6
Ras Bakr	8	3,504	40%	320	16.6
North Hurghada	8	3,504	40%	480	16.6
(East of Oweinat)	7	2,190	25%	160	26.4

2) At 10% rate of discount, and without deducting any income per kWh from potential sales of CERs (CO_2-payments)

According to NREA estimates of production, windfarms located at the sites will have capacity factors in the 40% to 50% range. The sites, which together allow 3500 MW of capacity to be installed [2], are ranked in the table by their economic cost of production, which ranges from 13.3 to 16.6 piaster per kWh for year 2004 state of the art windfarm technology and price. The least cost site is the Gulf of El-Zayt, site 1. But since its development must await the planned construction of the transmission line from Zafarana to Hurghada, the unallocated MW-potential at the Zafarana-site owned by NREA will be developed first. All sites are located near the planned transmission line; the cost of connection, therefore, does not change the ranking.

According to estimates from work on the national wind atlas, the next best wind resources in Egypt are found in El Qweinat in Southern Egypt. The drop in wind resource quality is substantial: the average annual windspeed of 6.7 m/s at the East of Oweinat site results in a capacity factor of 25% only. The region is scarcely populated; electricity is provided by isolated grids connected to diesel

[1] The location of the sites is shown on the map on page 3.
[2] The total economic potential at the Gulf of Suez may be larger than 3500 MW. It is likely that individual wind pockets can be found in between the sites.

generators. The value of diesel fuel is higher than of natural gas, yet, wind-diesel systems are too expensive and the wind regime is too low to make it an attractive investment option.
The results of table 1 are represented in graphic form in figure 2.

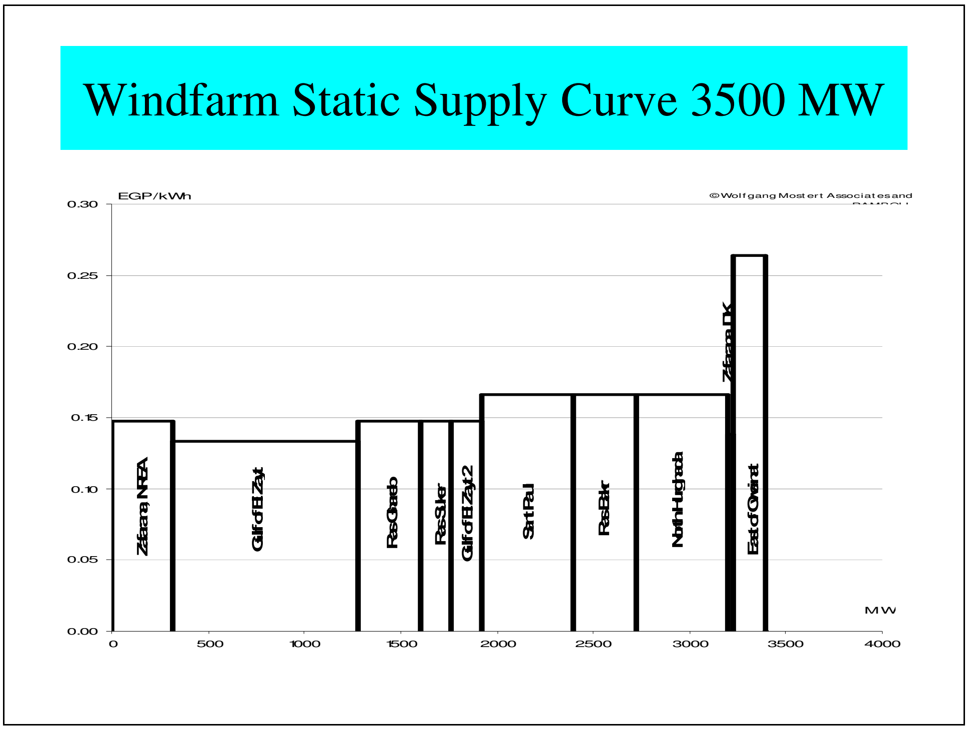


Figure 3: Egypt 3500 MW Wind Farm Program, Static Supply Curve

The last column, for East of Qweinat, falls outside the 3500 MW program.

1.2 Assumed Cost Structure, Year 2004 Technology and Prices

The windfarm costs of production shown in table 1 are based on the cost assumptions, listed in tables 2 to 4 below.

Table 2: Windfarm Economic Cost of Investment per MW, Year 2004

	US$/MW	% of total
Project Development Cost	33,000	4%
WT supplier contract	695,000	81%
Civil and Electrical Infrastructure	125,000	15%
TOTAL	820,000	100%

The economic cost of investment of US$820 per kW, by definition, does not include payment of import duty (8%) or sales tax (10%), interest during construction and need for working capital. The WT-supplier contract includes also the cost of training, a three year warranty, a crane and spare parts. The cost of investment in civil and electrical infrastructure is lower than normally seen in international projects for two reasons. First, the cost of civil works is lower than average because there is no need for road construction, neither on the sites ("flat" desert area) nor from the roads to the sites (they are located close to the coastal road). Second, the cost of electrical infrastructure does not include the investment in the substation, it is paid for by an annual usage fee (see table 4).[3]

The cost assumptions for O&M are listed in table 3.

Table 3: Cost of Operation, Maintenance, Rehabilitation and Decommissioning

1. Annual O&M	US$
- Windfarm staff (EGP30,000 per year increasing with BNP/capita growth rate)	5,357/MW
- O&M consumables, from year 4: 0.8% of WT-contract increasing 3% per year	5,560/MW
- Office cost, vehicles operation & replacement, telecom (EGP 10,000/MW/year)	1,786/MW
- Annual land lease payment in per cent of electricity revenue	2%
- Insurance, annual payment in percent of cost of investment	0.6%
2. Overhaul after 10 years, % of cost of investment	20%[1)]
3. Decommissioning of site year 21, % of investment in civil and electrical works	0%[2)]

1) Equal to 25% of original investment in blades, 50% gear, 30% electric generators.
2) This percentage, originally set at 15% of civil and electrical works was, following advice by NREA experts reduced to 0%.

One can discuss the validity of the assumptions for individual O&M cost components; what is important is the realism of the total annual amount per year. Expressed as an annuity over 20 years, the average annual O&M cost equals 3.1% of the original cost of investment, including the annual user charge for the sub-station increases annual O&M to 4%. This corresponds to the medium end of international windfarm O&M data and rules of thumb on O&M costs.[4] The estimate is justified by the lower cost of staff, and by the relatively modest payments for lease of land, set at 2% of electricity revenue.
The specific assumptions made in table 4, eliminate the cost of the 220 and 500 KV-transmission lines as a cost-factor in the economic, and later, the financial analysis.

Table 4: Cost of connecting a Windfarm to the Transmission Grid

	EGP	US$
Cost of investment in 11 kV-line per km *(4 km assumed)* to substation	224,000	40,000
Cost of investment in 500 kV-line per km *(not charged to windfarms)*	801,000	180,000
Investment in Substation, 150 MVA, 0.4/220 kV *(charged by annual fee)*	33,375,000	7,500,000
Administrative and technical cost of connecting individual 50MW plant	400,500	90,000
Length of 220 kV-line to Zafarana	70 Km	70km
Length of 500 kV-line from Zafarana to Hurghada	200 Km	200km
Share of cost of investment in 220 kV and 500 kV-line charged to windfarms		0%
Cost of annual O&M of transmission line, per MW, 1.5% of investment	530	119

[3] Depending on the pricing policy of the transmission utility, the windfarm's share in the cost of investment in the substation and connecting 11 kV-line will either be charged fully upfront or amortized through a lease cost / usage charge levied by the utility for providing this facility. The latter assumption is sued in the report.

[4] David Millborrow, known from his articles on Windfarm costs in Wind Power Monthly, uses two reference figures. One is US$15kW + US$0.002kWh, the other is US$25/kW + 0.004/kWh. A detailed study by DEWI, "Studie zur aktuellen Kostensituation 2002 der Windenergienutzung in Deutschland" using O&M cost data from more than 400 German windfarms showed that the cost of O&M from the year 5 onwards amounts to 5% of the cost of investment.

On an NPV basis, the cost of investment makes up 80% of the cost of production of a windfarm, the cost of O&M the last 20%; in German and US windfarms the break-down is 70%/30%. The break-down of the O&M-cost assumptions per kWh of output are shown in figure 3.

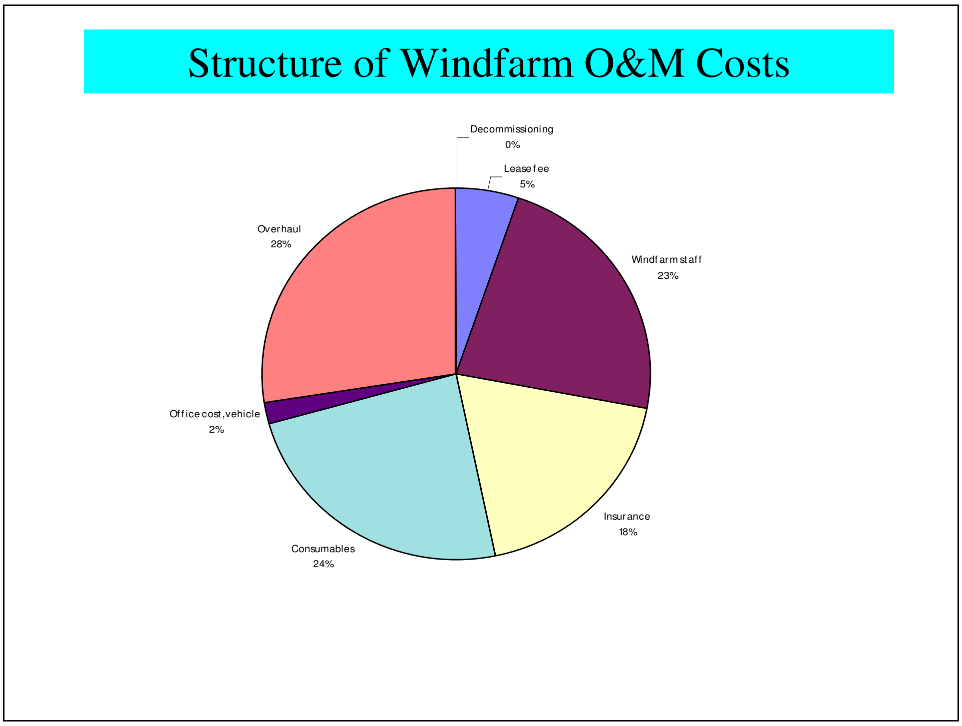


Figure 4: Composition of Windfarm O&M Costs (Percentages)

1.3 Economic cost of land

Windfarms take up large land areas - roughly 250,000 sq.m. per MW. But they make very extensive use of land. The space in between the turbines, therefore, can be used for other economic activities.

The principles for fixing the prices for lease of land by windfarms have not been fixed yet in Egypt. It was not necessary until now since project development was limited to the Zafarana site, which was given to NREA as a gift by the Government. Once project development is handed over to the private sector, however, the Government needs to develop pricing principles for the lease of land.

The land along the Gulf of Suez is desert owned by the Egyptian State. To prepare a piece of land for setting up a windfarm involves some costs, including costs for mine clearing. The cost for this is in the financial modelling of the report charged upfront to the investor and included in the 4% cost of project development, listed in table 2.

Depending on the decision of the Government, the investor can purchase or lease the land. What *leasing fee, corresponding to economic value of the land*, should be charged?

In free competition, the economic value of the land is equal to its market price as this gives the value of land in its highest-value yielding application.[5] The *value of the land in its best alternative use* is the following:

- The land has zero value for Government as long as no investor is interested in using it.
- The land has zero value for windfarm investors as long as the market price for output is lower than cost of production (not including payment of land lease).
- The land has a positive value for a windfarm as soon as market price for its output is higher than the cost of production (not including payment of land lease).[6] In that case, the land (or more precisely, the wind resources at the land area) has a positive resource rent, which is equal to the difference between the annual revenue and the levelized cost of production. The Government, as land owner, can expropriate it partly or totally by imposing a leasing fee for the land on the investor.
- If alternative economic activities exist, such as a tourist resort or an industrial processing zone, which, making intensive use of the land, get a higher net value added per square meter of land (*resource rent of the land*) than windfarms, the land will not be used for windfarms, unless the activities allow to "squeeze in" a windfarm onto the site also.[7]

According to NREA, the eight sites have no alternative use other than windfarm development. The land is of too low quality to be used for agriculture. The sites are located somewhat inland, not directly along the coast. They, therefore, do not could conflict with use of the coastal area nearby for tourist resorts.

In the absence of alternative uses, the value of the land is determined exclusively by the resource rent, which the land can yield when used for windfarms. During the non-commercial phase, the economic resource rent is negative since the economic value of wind farm production is lower that its economic cost. The financial resource rent for investors is positive if the subsidy given to windfarm production is so large that it drives the financial cost of production below the free power market price for their electricity and CER output. As soon as windfarms, from around 2014, become economically viable, the economic rent at the best sites is positive.

The economically rational pricing policy for the Government would be to charge a "close-to-zero" fee during the *non-commercial phase*, and to let the fee be determined by a bidding process for the land once the commercial phase is reached.

In this report all quoted financial and economic costs include for both phases *a leasing fee of 2% of electricity sales-revenue*. This fee, incidentally, is similar to the leasing fee charged by the UK's Crown Estate for off-shore windfarm sites.

[5] An exception to this occurs for windfarms operating under a feed-in-tariff regime, which pays wind farms a tariff, which is both above the economic value of windfarm output and above the financial cost of windfarm production. In that case, the value of the land has an artificially created financial resource rent. The rent will be split in a bargaining game between the windfarm investor and the owner of the land leasing space to the investor.

[6] Please note that an economists definition of "cost of production" always includes a normal rate of return for the investor.

[7] The land value increases if combined use can be made of the land. The space between the turbines can be used for extensive agriculture such as grazing and/or for intensive production such as horticulture.

2 ECONOMIC VALUE OF AVOIDED COSTS IN THERMAL POWER PRODUCTION

2.1 Economic Value of replaced Thermal Power Production

The economic value of windfarm production is equal to the economic value of the cost savings in the national power system. These consist of "*internal*" cost savings in the power system, which are savings in costs of the power utilities, and of "e*xternal" benefits*, which are avoided damage costs for society from reduced emissions in thermal power production.

How will the electricity output from the windfarms affect the operation of the power system? Windfarms have, next to hydropower, the lowest short term marginal cost of production, and, since the "wind-fuel" cannot be stored, windfarms will "always" occupy the first place in the merit order of production in the national power system. Fluctuations in wind farm production lead to upward and downward adjustments in medium and peak load thermal power production. [8]

Egyptian thermal power plants are either gas fired steam turbine plants or CCGT plants, oil fired generation is negligible. New steam turbine power plants have higher cost/MW[9] than CCGT-plants and an efficiency of 41 % as compared to 57% for CCGT plants. Yet, according to NREA, *a mix of 30 % CCGT and 70 % steam* is suitable for the load conditions in Egypt with an average load factor of 62 %. CCGT plants are suitable only for coastal areas on the Mediterranean: if CCGT-plants are placed in areas where temperatures approach 40 C in summer, they could suffer from up to 20 % efficiency loss. In the merit order system, the CCGT plants work on full load basis due to lower fuel costs and because CCGT-plants incur much larger large efficiency losses than steam turbine plants when the plant is operated at part load.

Since CCGT-plants operate in base load mode only, they will only in exceptional cases be affected by the penetration of windfarm generated electricity. The conclusion is that windfarm production reduces the output from steam turbine plants only. The calculation of fuel-savings (and variable non-fuel O&M costs) will be based on the average net energy efficiency of steam turbine plants, which in 2004 is 37.5% increases gradually to 42% by the end of 2024.[10] The CO_2 savings decrease from 0.50 kg CO_2 per kWh in2004 to 0.44 kg in 2024.

The sensitivity analysis in this report includes, however, also the impact of using the overall average for the thermal plant mix.

The 70%/30% mix is used for calculating the value of replaced investment in thermal capacity. The cost of investment of steam turbine plants is expected to decrease 1% per year; CCGT-plants half of that.

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[8] Part of the fluctuations will be handled by adjustments in hydropower production. But this can be ignored. Due to the overall energy constraint of hydropower, all hydropower production will be used up during the year. The existence of windfarms does not change that fact. The existence of fast reaction-time hydropower, however, saves on the cost of fuel for spinning reserve.

[9] The Gas turbine plants have a lifetime of 25-30 years while steam power plants have an average life of 35 years.

[10] The overall efficiency of thermal power (CCGT+ST) is expected to increase from 40% in 2004 to 48% in 2024.

2.1.1 Cost structure of CCGT- and steam turbine plants

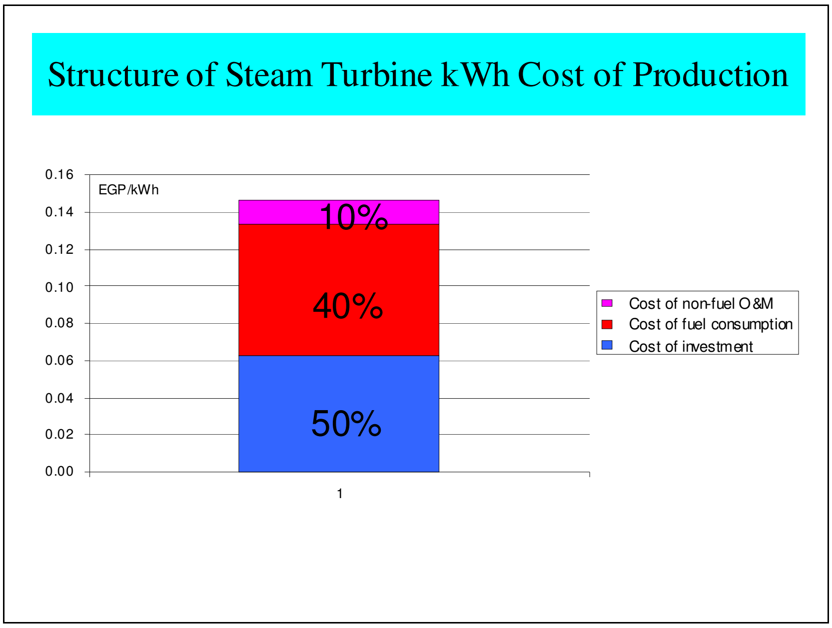
The assumed costs of thermal power production in Egypt, which are used for the calculation of the avoided cost savings, are shown in table 3.

Table 3: Cost Data for Gas fired Thermal Power Plants in Egypt

Cost Data for CCGT and Steam Turbine Power Plants	EGP/MW	US$/MW
Cost of Investment average CCGT and Steam from 2004	3,022,880	539,800
- Investment in CCGT plant in 2004	2,536,800	453,000
- Investment in Steam Turbine Power Plant in 2004	3,231,200	577,000
Annual operating hours during lifetime	5,500	
Non-fuel cost of O&M: fixed costs, EGP per MW per year	53,400	9,536
Non-fuel cost of O&M: variable cost, EGP/kWh	0.0027	0.0005
Operating lifetime	30	Years
Efficiency of CCGT, years 2004 and 2024	57%	62%
Average efficiency of steam turbines, years 2004 and 2024	37.5%	42%

Figure 4 shows the composition of the economic cost of production of a new steam turbine plant with a thermal efficiency of 40%, which amounts to 14.5 piaster/kWh at the economic price of gas consumed at the thermal power plants of 30 piaster per m^3 (the year 2003 tariff is 14 piaster).[11] In that case, the cost of fuel amounts to 40% of the cost of production per kWh.

Figure 5: Structure of kWh Cost of Production of Steam Turbine Plant



[11] The average price in 2001/02 gas sharing contracts is US$1.05/mbtu; cost of transport from wellhead to power plant is US$0.1/mbtu, which results in a domestic full cost-coverage price of US$1.15/mbtu = 6.4 EGP7mbtu = 22 piaster per m^3 gas. The year 2002/03 price of 14 piaster has not been changed since pre-devaluation days in the mid-1990s.

The cost structure of thermal power production consists of *variable* and *fixed costs* of production. Some costs are not saved when wind farm production replaces thermal power output. Table 4 summarizes the assumptions in the economic-financial models on the extent to which individual cost components are affected. The capacity value of wind energy is based on the cost of investment in a 30%/70% mixture of CCGT- and steam turbine plants; the year 2004 cost of investment per MW is expected to decrease 1% per year for future new power plant investments in line with the normal productivity increases found in mature industries. The value of O&M savings, mainly fuel consumption, is based on the average energy efficiency of steam turbine plants during the lifetime of the wind farm. It is estimated to increase gradually from 33% in 2004 to 43% in the year 2024.

Table 4: Assumptions on saved Fixed and Variable Costs of Production

1. Power Plants used in Model Calculations		
Reference plant for savings in new generation capacity	Future CCGT/ST-mix of 30%/70%	
Reference power plant for savings in power system O&M	STs with efficiency 33% (2004) -43% (2024)	
2. Savings in thermal power system		
Fuel savings per kWh of wind farm adjusted for line losses	100%	of average fuel consumption per kWh at steam turbine power plant
Cost of non-fuel O&M	100%	of variable non-fuel ST O&M cost
Capacity savings due to reduced Loss of Load Probability	60%	of capacity factor of wind farm (annual production/capacity*8760)
Capacity factor of windfarm park	45%	
Investment in MW thermal saved by 1MW windfarm	0.27	MW thermal capacity
3. Impact on line losses in transmission & distribution system		
Saved regional line losses due to local wind power production	0%	

2.1.2 The capacity value of wind power

The "*capacity value of wind power"* refers to the savings in investment in new conventional power generation capacity due to the availability of wind farm capacity. The size of the capacity value depends on how expansion plans for thermal power are affected by the growth in new wind farm capacity.

Wind farm capacity is not "firm capacity" like thermal power. It depends on the availability of wind. This leads some power system planners to conclude that wind farms have no impact on the investment programme in thermal power capacity. This view is too simple. An *optimised power expansion plan* aims at the level of capacity, which provides the system with the optimal "*loss of load probability" (or LOLE, "loss of load expectation"*) [12]. It is assumed in this report that in order to promote a least-cost system of electricity supply, the regulator will require the system operator in charge of preparing the long-term power system supply and demand forecasts, to take the value of windfarm capacity is taken into account when the need for new generating capacity is estimated. In that case, one can be certain that the windfarm program will save thermal capacity.

[12] In economic terms optimality of the power system is defined by the equation: "cost of investment in marginal additions to capacity = marginal reduction in loss of load probability in MWh multiplied by the cost of per MWh of lost load at the level of consumer".

Sophisticated simulation models for the power system can estimate the investment needs in thermal power for cases with and without wind farm production. Based on the difference in the resulting thermal power expansion plans one can see how many MW of thermal power capacity are replaced by a MW of wind farm capacity. This, the "*load carrying capability*" – or *"capacity value"* of wind power, is expressed as a percentage of the rated MW-capacity of the wind farm.

Provided that windfarm capacity is properly integrated in national power planning, the load carrying capability depends (i) on the local wind regime, (ii) on the specific characteristics of the integrated power system, (iii) on the level of penetration of wind-generated electricity and (iv) on the degree of the concentration of installed national wind farm capacity. Geographical dispersion has an "averaging" effect, which reduces the impact of fluctuations. Both for very short-term variations, which affect power quality (voltage flicker and voltage steps), but also the variability of wind farm output on longer timescales (minutes upwards). A high concentration increases the system risks on the transmission grid compared to a scattered distribution of windfarm capacity, and thus, reduces the capacity value. But typically, for wind farms in reasonably good wind areas with 25-35% capacity factor, these simulation exercises result in an estimate of the load carrying capability of somewhere between 15%-22% of rated power.[13]

In the USA, the Standard Market Design rules proposed by the Federal Energy Regulatory Commission provide for wind farms to participate in the capacity market. PJM Interenconnections, (which serves Pennsylvania, New Jersey and Maryland) allows wind generators to claim and sell capacity credits within its six-state operating area, providing wind generators with a revenue equal to around US$0.01/kWh.[14] The capacity value is based on a three year rolling average of a wind-farms actual performance during PJM's peak hours. Until that three year average is established , PJM sets the capacity value of the turbine's nameplate rating.

EEHC has not made model-simulations of the impact of windfarm capacity on the capacity needs of thermal power. In the absence of power system modelling, a simple rule-of-thumb method is to use the wind farm's *"capacity factor"*[15] as an estimate of the load carrying capability of wind power. This is an overestimate of the true capacity value, which needs to be adjusted to a more realistic level, in particular, when capacity factors as in Egypt are very high. This, even though the output of the Zafarana windfarm shows a good match between the production profile and the load curve of the national power system during a day and during the seasons. This report, therefore assumes that *the "capacity value" or "load carrying capacity" of wind farms is equal to 60% of the capacity factor*.

For the 45% capacity factor of a Zafarana wind farm, the 60% assumption, therefore results in a replacement of 0.27 MW of new thermal power capacity for each 1 MW of windfarm capacity. On a kWh basis, the *capacity value of windenergy is equal to 1.5 piaster per kWh.*[16]

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[13] Simulations in Ireland for wind energy capacity up to at least 800 MW resulted in a capacity credit of about 20%. An early paper on the ESB system determined a capacity credit of 35% of wind capacity for the first few megawatts (i.e. approximating to the annual capacity factor), falling to 14% for 2000 MW and 11% for 3000 MW. See pp. 40, of Commission for Energy Regulation/OFREG NI: "The impacts of increased levels of wind penetration on the electricity systems of the Republic of Ireland and Northern Ireland: final report", 2003.
[14] Windpower Monthly, volume 19, no. 6, June 2003, pp.44.
[15] The ratio of average to rated power of the wind farm = "annual delivered MWH to the grid/(installed MW x 8760)".
[16] Please note that the way the capacity value is calculated, the *capacity value per kWh* of windfarm production is the same for all capacity factors.

Generators in a conventional power system deliver a range of socalled *ancillary services*. These are essential services that operators use to control the power system such as operating reserve and reactive power, short-circuit current contribution and black start capability. Wind farms are unable to produce these ancillary services in a dispatchable, controllable way.

2.1.3 Savings in cost of annual O&M at thermal power plants

1 kWh delivered into the public grid by a wind farm replaces 1 kWh of thermal power production, except for corrections for differences in transmission and distribution losses caused by power transport to a center of demand located either far away from the windfarm (downward correction, as the thermal power plants presumably are located closer to the area of consumption) or to nearby local consumption (upward correction). [17]. In the financial model, one kWh of replaced thermal power production thus saves:

- the *cost of fuel consumption* per kWh, based on a conversion efficiency of replaced thermal power production of 37.5% in the year 2004, increasing gradually to 43% by 2024;
- the full *variable non-fuel cost of O&M* per kWh at the thermal power plant.

2.1.4 The economic price and financial tariff of gas at power stations[18]

The major uncertainty in the O&M calculations relates to the estimation of the price of gas at the power stations, both in the economic cost calculations as well as in the financial tariff. One source of uncertainty is the choice of methodology, the other the long-term forecast for the price of gas.

Pricing policy for gas and year 2003 price of gas

Whereas the prices in the production sharing contracts for gas exploration, development and production are fixed in dollars, the price of gas paid by the power plants is fixed by the Government in EGP independently of the exchange rate or of the rate of inflation. [19] Devaluation, therefore, leads to a decoupling between the cost of production of gas and the tariff paid by the power plants, until the Government adjusts the tariff. The *gas price of EGP 0.14 per m3* for thermal power plants, which in year 2000 was equivalent to US$1.05 per Mbtu in 2000, had due to the devaluation of the Egyptian pound dropped to US$0.72 in May 2003.

Estimating the financial tariff of gas in year 2004

The *issue* related to the forecast of the financial price of gas in 2004 is how to approach the facts that (i) the price of gas charged to the power stations is fixed by political will in Egypt, (ii) the year 2003 price of EGP 0.14 per m3 is very low, (iii) has not been changed for many years and (iv) is

[17]). The calculations in this report following 1 kWh wind = 1 kWh thermal assumption do not take into account the fuel consumption of spinning reserve, which is needed to adjust national generation for any shortfall caused by short-term fluctuations in windfarm output. The fuel consumption of the extra windfarm-related spinning capacity has to be deducted to arrive at the true savings in natural gas consumption. But, the size of this "extra share" is difficult to estimate: because demand fluctuates, spinning reserve is needed in any case; technically, the fluctuation of windfarm production has an impact like negative demand.

[18] Please refer to Annex I for a detailed analysis of gas prices in Egypt and the netback value of gas.

[19] For details on this calculation and on the calculations leading to the economic costs estimates, please refer to Annex I.

lower than the *domestic LRMC of gas supply to power stations* of US$1.15/mbtu: the average wellhead price in recent contracts is US$1.05/mbtu, the marginal cost of pipeline transport to the power plant adds US$0.1/mbtu.

Worldwide experience cautions against underestimating political unwillingness to remove price subsidies. Yet, it is not good methodology to assume in financial analysis that a politically fixed price, which is artificially low by national historical standards, will not be increased in coming years. The financial cost calculations in this report assume that the present under-pricing is temprary, and that the Egyptian Government sooner or later will fix the gas tariff again at a level, which reflects the full domestic cost-of-supply of US$1.15/mbtu. All figures in this report on the financial cost of thermal power from the year 2004 and onwards are, therefore, based on a gas tariff of 22 piaster per m3, see table 5.

Table 5: Fuel Cost Data – Financial Cost

Price of Natural Gas	EGP/MBTU	US$/MBTU	EGP/m3
Fuel price at power plant in Egypt, year 2002	4.039	0.72	0.14
Average gas price in recent production sharing contracts	5.880	1.05	0.20
Average transmission cost of gas to power plant	0.543	0.10	0.02
Expected fuel price year 2004 (=economic domestic LRMC)	6.423	1.15	0.22

Economic price = LRMC of domestic supply or netback value of LNG-exports?

Opinions differ about the *correct approach to fix the economic price of gas* in Egypt.

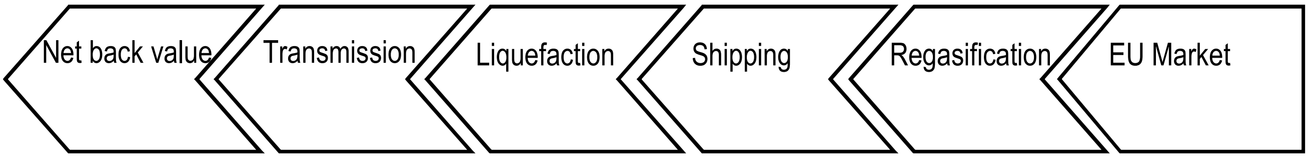
One school of thought insists that the *domestic LRMC of supply* of gas to the power stations (above estimated at 22 piastre/m^3) reflects the economic value of gas in Egypt. That assumption is too simple in view of the importance the Egyptian government attaches to the promotion of gas export as a foreign exchange earner.

This report, therefore, adopts the alternative: the *opportunity cost of gas consumed at the Egyptian power stations equals the value of the alternative use of gas for exports*. Technically speaking, this approach assumes that the amount of Egyptian gas exports is not constrained by the market size, ie, Egypt will be a price taker.

Mainly, at present and in the future, Egypt exports natural gas in the form of LNG to the EU-market, which has a huge and growing import demand, see Annex I. Egypt can continue to add to its export capacity by building new LNG trains in the foreseeable future; annex I shows a pipeline of six to seven projects, of which at least two look to be certain. Under these conditions, the economic price (or value) of gas is equal to the *netback value of LNG exports to Europe* plus the value of saved transport costs to the power plant.

The calculation of the net-back value of LNG assesses the LNG export chain.[20] From the market value at the export market – most likely in EU – backwards in the process of treating and transporting the LNG:

[20] For details, please refer to Annex I.



Exporting of natural gas as LNG includes 5 main stages in the LNG-Chain:

- Gas production (or purchase of gas from producers)
- Transmission to the export harbour
- Liquefaction of the gas
- Loading and ocean transporting
- Reception and regasification

Egypt exports *natural gas by pipeline* to Jordan and, in the future, according to recent political discussions, to Libya. These two markets are demand constraint; meaning that the price taker condition is not fulfilled.

Forecast price for LNG

The last issue of methodology concerns the *choice of the price of LNG*. Historically, the price of gas has been linked to the price of crude oil. Although there is a trend towards a decoupling of the prices, the relationship still holds. The forecast price of LNG in this report is, therefore, linked to the price of crude oil per barrel, see Annex I. The netback price is based on an *oil price assumption of US$21 per barrel*, which expressed in 1985-price levels equals the historical long-term average of US$10/bbl of the last 110 years, see the charts in Annex VI. The sensitivity analysis shows the impact of a price of US$25/bbl is tested; which in NPV-terms for a plant set up in 2004 equals an annual 3% increase in the real price of oil during 20 years.[21]

The economic price, as seen in table 6, is estimated at 30 piaster per m^3.

Table 6: Economic Price of Natural Gas based on Netback Value of LNG Exports

Economic price of NG based on Netback price of LNG exports	EGP	US$	
Oil price assumption 2004-2023, price per barrel of oil		21	per barrel
LNG (cif) as function of oil price, using historic data for relationship		2.8	/MBTU
Cost of ship transport		-0.43	/MBTU
Cost of liquefaction		-0.9	/MBTU
Transport from natural gas reservoir to liquefaction plant		0.0	/MBTU
Marginal cost of transport of NG from well-head to power plant, 5%		0.005	/MBTU
Economic price of Natural Gas consumed at Power Plant	8.536	1.5	/MBTU
Economic price per m^3 of gas consumed at power plants	0.30	0.053	per m3

[21] Studies – worldwide - since 1979 on the economics of renewable energy systems, very frequently use the 3% real oil price increase as their base case assumption. That, as argued in Annex VI, assumes a fundamental parameter shift in the way the oil market has operated during the last 130 years. The analytical justification for that shift is not explained.

The output of a single wind farm, saves too little gas to have any impact on the ability of Egypt to increase its LNG-exports to Europe. The output of 2,000-3,500 MW of windfarm has a perceptible impact on the level of national natural gas consumption, see figure 6, page 43. The reduced national gas demand allows the well-head producers of natural gas to increase their LNG exports.

2.1.5 Reduced line losses - value of distributed power

Decentralised power production, which is located nearer to a centre of demand than the centralized thermal power stations that otherwise supply the required power, reduces the line losses in the transmission and distribution grid. The loss reduction depends on how much output is consumed by consumers living close to the wind farm.

Table 7: Impact of Windfarm Output on Line Losses in Transmission and Distribution

Impact on Line Losses in Transmission and Distribution System	
Saved regional line losses due to local wind power production	0%

The calculations in this report assume that the transmission (and distribution) losses of bulk supply of electricity are the same for windfarms and for thermal power plants, meaning that 1 kWh of wind farm output replaces 1 kWh of thermal power. In the short term, the output from Zafarana is sent exclusively northwards to the Port of Suez centre of demand. Once the Zafarana-Hurghada transmission lines has been build, the physical stream is likely naturally to go southwards to the Hurghada centre of demand. The demand from the Hurghada tourist resorts is below the average annual supply from the windfarms, once installed capacity reaches the 1-2 GW scale.

2.1.6 Cost of intermittent supply

The cost of "firming and shaping" intermittent wind energy into a "usable product" – the cost of catering to demands of shortfall and excesses of generation on a virtual imbalance market are not negligible. Some idea about the magnitude might be gained from the imbalance generation charges, which penalize windenergy under the British NETA-scheme, although being a financial price, they are supposed to reflect the true economic cost of imbalances. These costs are higher than the non-accounted for cost of fuel consumption from spinning reserves, mentioned in 2.1.3. The cost of intermittent supply will decrease over the next decade as new technology is being developed that enables grid operators better to manage intermittent supply. On the windfarm side, better technology can improve the quality of supply, albeit at a cost. A recent Spanish report estimates the cost in Spain of boosting accurate production forecasts to 30 hours ahead and making wind plant provide the reactive power needed by the grid twill each add €0.005/kWh to production costs.[22]

Since the cost of intermittent supply is not included in the economic cost estimate, the economic value of windenergy, is slightly overestimated.[23]

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[22] See Wind Power Monthly, June 2003:"Industry fears dip in investor confidence". The costs may be overstated as the calculation is done by a lobby group arguing for an increase in windpower tariffs.
[23] Milborrow D, "Penalties for intermittent sources of energy", submission to UK Performance and Innovation Unit energy review, 2001. "As the wind capacity rises, however, measures must be taken to ensure the wind variations do not reduce the reliability with which demand is met and that frequency and voltage tolerances are not exceeded. When

2.2 External Economic Benefits

2.2.1 Damage costs or abatement costs?

Wind power produces no emissions during operation. Coal power plants emit SO_2, NO_x, CO_2 and particles emissions into the air, and pollute soils and water resources with heavy metals and sludge. In Egypt, where natural gas is used as the almost exclusive fuel in thermal power plants, only the NO_x and CO_2 emissions are relevant. The better environmental performance of wind farms is an external benefit of wind power [24]. It consists of the savings to society from reducing the environmental impact of thermal power production.

There are two ways to calculate the *value of environmental costs*:

- by estimating the *damage costs* imposed on external members of society by the *negative effects of pollution*;
- by estimating the costs of *abatement measures* to avoid pollution.

Both methods have their uncertainties and weaknesses. The logical procedure is to choose what for a specific case provides the lowest estimate, assuming, that if damage costs are lower than the cost of abatement, then it is reasonable to assume that the abatement measures are not implemented.

2.2.2 Value of reduced NO_x emissions

NO_x emissions in power production are very plant specific, and the average NO_x-emissions in Egyptian power plants are not known to the author of this report. The value of avoided damage cost from NO_x-emissions is, therefore, ignored in the economic rate of return calculation in this report. It makes no discernable difference, as the "underestimation-error" is small, and not larger than the "overestimation errors" that are listed in section 2.1. If average NO_x-emission in thermal power are equal to the US-average of 2.7 pounds per MWh and the economic value is equal to the US market price for NOx-quotas of US$750 per ton, *the economic value amounts to 0.5 piaster per kWh (UScents 0.09).*

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wind is introduced on a utility network additional flexibility of various sorts must be acquired in order to compensate for possible fluctuations in the level of wind generation. Costs may be incurred as follows: (1). To keep additional generation capacity in readiness (to meet demand if wind is unavailable); (2) To obtain additional flexibility from generators or demands to maintain energy balance in each metered period (half-hourly in the UK); (3). To obtain additional flexibility from generators or demands to maintain power balance continuously within half-hourly trading periods. This will be a mixture of response (automatic frequency sensitive action) and reserve (manually instructed action) of various speeds of delivery and endurance. At low penetration levels the flexibility costs are not significant. However, as the amount of intermittent production increases, these costs will increase. The studies mostly suggest that the costs of these services add up to about £0.5/MWh at 2% wind, rising to around £1/MWh at 10% penetration."

[24] Defined as an economic benefit of an activity, which is not included in its market price.

2.2.3 Value of CO_2 Savings

In Egypt, the value of reduced CO_2-emissions is equal to their price when marketed and sold as certified emission reductions, CERs, to investors from Annex I countries. The value is taken into account in the environmental benefit calculation. But since the CO_2-benefit has a monetary value for the windfarm owner, it makes better sense analytically to deduct the value of CO_2-revenue per kWh from the economic /financial cost of production in order to get the economic/financial cost of production price for electricity, rather than adding the "external benefit" of CO_2-savings to the "internal benefits" of the power system.

It is evident from the large price ranges shown in table 8 that there is no international market for certified CO_2-reductions, but a number of separate markets. The highest prices are in the emerging national allowance markets. In the CDM market, the largest buyer so far has been the PCF, which by its statutes limited to pay a maximum price of US$4 per ton CO_2. The upper level price is reserved for low-risk projects such as first class landfill and windfarm projects.[25]

Table 8: "International Carbon Market" Price Trends Year 2001-2002

	Price per ton CO_2
Annex II (OECD)	US$0.40 to 7.30 (average $1.00)
Joint Implementation projects	US$ 3 to 8
Clean Development Mechanism	US$ 1.50 to 4.00
Smaller, national schemes (e.g. UK)	~ US$ 18 (periodically)

Source: PCFplus "State and Trends of the International Carbon Market"

In the absence of a true operating international market, the PCF-price of US$4 per ton CO_2 is used as base case assumption. The year 2004 emissions of 0.50 kg CO_2/kWh give a *CO2-revenue of 1.1 piaster/kWh;* falling each year, due to better thermal power plant efficiency to 1.0 Piaster/kWh in 2024 when the average emission in steam turbine plants is 0.43 kg/CO_2. The sensitivity analysis also covers scenarios for prices of US$8 and US$2 per ton CO_2.

CDM project developers can chose between: (i) a crediting period for a maximum of seven years, which may be renewed at most two times or (ii) a maximum crediting period of ten years with no option for renewal. For wind farm projects the obvious choice of crediting period is three times seven years. It is not 100% clear at project start how many emissions per kWh can be claimed during the second and third periods, as the baseline is reconsidered after each seven years. But the long term power expansion plan of EEHC provides good guidance.

[25] See Annex IV for more details on the international CDM-market.

2.3 Result: Sum of Internal and External Benefits

Adding the different benefits of windfarms, we get the results summarized in table 9. The table estimates the *"internal" economic value* (without the value of CO2-savings) at 10.8 piaster per kWh. The value, due to higher energy efficiencies and lower costs of thermal power plant investments falls to 9.9 piaster in the year 2004. The economic value is higher than the *financial value of the savings to the national power system of 8.8 piaster per kWh* because of the difference between the "LNG-netback value price" of replaced natural gas consumption of 30 piaster/m^3 and the year 2004 financial "national cost coverage" price for gas of 22 piaster/m^3 for the power plants.

Table 9: Total Economic and Financial Value of 1 kWh of Windfarm Production

Total Economic and Financial Value of 1 kWh of Windfarm Production		
1. Savings on O&M Costs in Steam Turbine Plants	EGP/kWh	US$/kWh
Displaced non-fuel O&M cost in steam turbine plants	0.003	0.000
Value of saved fuel in steam turbine plants, financial cost	0.054	0.010
Value of saved fuel in steam turbine plants, economic cost	0.072	0.013
Subtotal: saved financial costs for thermal power system	0.056	0.010
Subtotal: saved economic costs for thermal power system	0.074	0.013
2. Saved Investment in new Power Plant Capacity (steam + CCGT mix)		
Investment in thermal power capacity saved by 1 MW wind farm	0.27MW	
Annual output of windfarm, kWh per MW installed capacity	3,942,000MWh	
	EGP	US$
Value of saved investment in thermal MW capacity by 1 MW wind	816,178	145,746
Financial/economic value divided by NPV of future annual kWh-output	0.024	0.0043
4. Financial and Economic Value (excl. Environmental benefits)	EGP/kWh	US$/kWh
Financial value of savings in thermal power system, excl. Env.benefits	0.081	0.014
Economic value of savings in thermal power system, excl. Env.benefits	0.098	0.018
5. Saved CO2-emissions due to electricity generation from windfarms		
Replacement value of wind energy adjusted for transmission losses	100%	
Replaced CO2 emission per kWh of windfarm production	0.496Kg CO2	
Price of 1 ton of CO2 replacement sold on international market	4US$	
	EGP/kWh	US$/kWh
Revenue from C02 replacement certificates per kWh wind energy	0.011	0.002
6. Total Economic Value of 1 kWh of Windfarm Production including CO_2	0.110	0.020

The logical *"bottom of the line" tariff for wind energy, which a profit-maximizing system operator* would be willing to pay to a windfarm in year 2004, is equal to the financial value of the "internal savings in the power system of 8.1 piaster/kWh.[26] The additional revenue from CO_2-certificate sales, increases the total income from windfarm operation to 9.2 piaster per kWh. This is 60% of the year 2004 financial cost of production – without deducting CER-revenue – of 15.2 piaster per

[26] Year 2002/03 tariffs for power (presumably before adjustment for devaluation) are 8.5 piaster/kW for CCGTs, 11.5 piaster for BOOT-projects and 10 piaster for NREA's windfarm PPAs.

kWh. Productivity improvements in the technology of steam turbine plants reduce the financial value of the cost savings in thermal power plants to 7.4 piaster/kWh in 2024; and the average financial value during the 20-years lifetime of the windfarm to 8.1 piaster = 53% of the financial cost of production.

For *Egyptian economy and energy policy, on the other hand, the rational "bottom of the line" PPA-tariff* is to pay 9.9 piaster per kWh in the year 2004, which adding the CER-payment provides the windfarm operator with a revenue of 11 piaster per kWh. That is 64% of the year 2004 economic cost of production (without deducting the economic value of the CER-revenue) of 14.8 piaster per kWh. Productivity improvements in the technology of steam turbine plants reduce the economic avoided cost to 8.9 piaster/kWh for a windfarm established in 2024, and the average economic benefit to 9.9 piaster per kWh = 67% of the economic cost of production.[27]

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[27] NREA's 10 piaster per kWh PPA for Zafarana is a politically negotiated price, which turns out to equal the "correct economic" price for windfarm production of 9.9 piaster.

3 YEAR OF ECONOMIC BREAK-EVEN BETWEEN COSTS AND BENEFITS

3.1 Forecast for Long-Term Productivity Increase for Windenergy

The future cost of production of a new windfarm in Egypt at a given site, depends on the annual productivity increase in windfarm technology, which results from the cumulative impact of the development in (i) the cost of investment per MW, (ii) the cost of annual O&M and (iii) the output per MW. The forecast made in this report for the three parameters are shown in table 10.[28]

The theoretical maximum conversion efficiency of wind turbines is 59% (Bitz-criteria). The present power coefficient of wind turbines is about 40%. The assumptions for the improvement in the electricity output per MW result in a 15% increase in the kWh-output per MW between 2004 and 2024, leading to a conversion efficiency of 46%. That is 78% of the theoretical maximum, equal to the level achieved by new CCGT-plants today.

Table 10: Average Annual Increase in Productivity of New Windfarms

Productivity Increase for future Wind Farms	2002-2010	2010-2020	2020-2025
Decline in Cost of Investment in Wind Farm	3.5%	2.0%	1.5%
Increase in Net Electricity Output per MW	1.0%	0.5%	0.2%
Decline in Cost of O&M per kWh	1.5%	1.0%	0.5%

Source: Qualitative assessment made by authors of the report, based on long-term trends in productivity improvement of windenergy from 1980-2002 (continuation of decline in rate of productivity increase).

The assumptions reduce the cost of production in the year 2024 to 57% of the year 2004 level, representing an average productivity increase (decline in cost of production) of 2.7% per year.[29] The productivity forecast continues the trend seen during the last two decades of a slow-down in the rate of productivity increase: in Denmark during the 1980s, the cost of wind turbine production decreased an average 8% per year, during the 1990s an average of 5%.

For windfarm investments at the Zafarana site, the implication is that the economic cost of production per kWh is reduced from 14.8 piaster for an investment in 2004 to 10.4 piaster for a year 2014 investment, and to 8.8 piaster for a windfarm established in the year 2024.

[28] Annex III has a table, showing the year-to-year productivity index resulting from these assumptions.
[29] This growth rate, by coincidence, is the same growth rate which resulted from the “learning curve” approach used by Task Force 12, which assumes that productivity increases (cost per kWh decreases) for every doubling of the (international market) for a market. Task Force 12 in their final report, based on their forecast of a continued growth worldwide in new annual windfarm capacity, estimated that the cost of investment per kW would decrease from US$765 in the year 2002 to US$440 per kW in the year 2022.

3.2 The LRMC-Supply Curve for a 3500 MW Windfarm Program

Figure 2, the "static supply curve" (page 21) for a 3500 MW program shows the cost of production at the best sites using year 2004 state-of-the art technology and prices. Figure 5 shows the "dynamic supply curve" for installing 3500 MW windfarm capacity by the year 2024. The assumptions defining the curve are: (i) the sites with the best wind regimes are developed first, (ii) 130 MW are installed each year, (iii) the productivity of windfarm technology increases according to the forecasts stated in table 13. [30] The bumpy path of the windenergy supply curve is caused by the phasing in of less attractive wind-sites over time, as the best potential is exhausted. The upper LRMC-curve for windenergy shows the economic cost of production without deduction of the (US$4/kg CO2) revenue from sales of CERs, the lower LRMC-curve shows the cost after deduction of CER-revenue. The latter is relevant for economic break-even analysis.

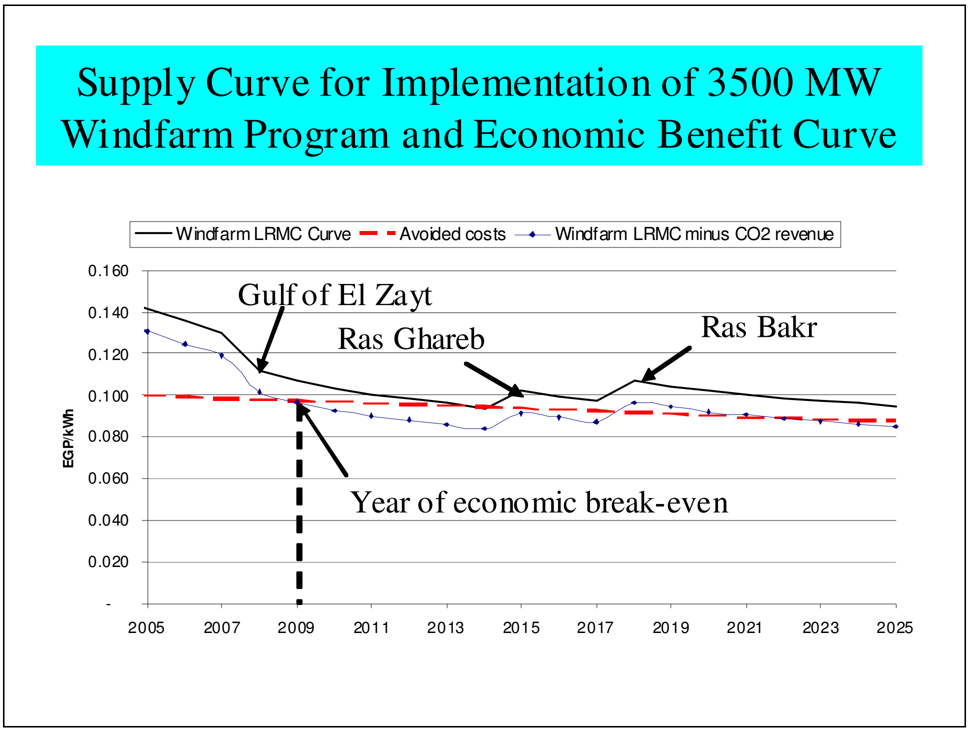


Figure 6: LRMC-Supply Curve and Economic Benefit Curve for 3500 MW Program

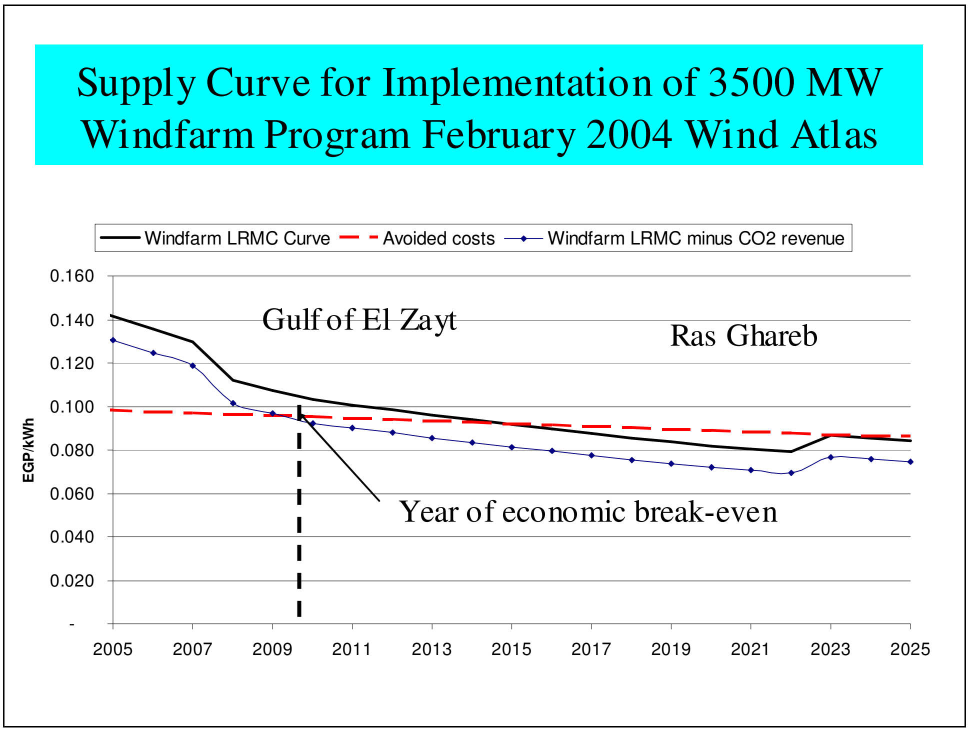
The "economic benefit (avoided cost) curve" in figure 5 shows the evolution in the avoided cost of thermal power production due to the supply of windfarm-generated electricity. The curve declines, due to improvements in steam turbine technology (increase in energy efficiency from 37.5% to 43% and 1% annual decline in the cost of investment), but not as steep as the windfarm LRMC-curve.

The intersection between the "avoided cost" and the "LRMC minus CO_2 revenue" curves shows the year of break-even between the economic costs and benefits of windfarm production. We note that this occurs in 2009, after which, there is a tight and fluctuating balance between costs and benefits of windfarm production. The tight balance confirms that the proposed "2% of electricity revenue" rate for the lease payment reflects the long-term economic rent of the windfarm sites.

[30] The spreadsheet model starts with the development of the Gulf of El Zayt site in 2004, which is not realistic as the MW potential at the Zafarana site is developed first.

3.3 LRMC Curve 2004-25 using February 2003 Wind Atlas Data

Data released with the publication in February 2003 of the Risø/NREA windatlas for Gulf of Suez revealed a wind regime which is superior to the winddata, which led to the establishment of the static supply curve (figure 2). A maximum potential of 20,000 MW can be developed in the region, of which 5000 MW for the Gulf el Zait windfarm site.



The above charts the new most likely development, assuming that 3000 MW capacity can be installed at Gulf el Zait with the wind regime of 4380MWh/MW shown in table 1. In this case, from the year 2015, windfarms are economic also without CER-revenue.

3.4 Sensitivity Analysis

Table 11 sheds light on the impact of uncertainties about the correctness of parameter values used in the economic (and financial) modelling. The table shows as base case the year of economic break even (2012) for a windfarm being exposed to a wind regime similar to the Zafarana site (since this is the site for the starting year) and its cost of production in 2012 (11.2 piaster per kWh).

Not surprisingly, the dominant uncertainties are:

- *On the cost of production side* the assumption concerning the *annual kWh-production per MW*. The wind conditions at Gulf of Zayt and Hurgada lead to an annual output, which is 11% higher, respectively lower, than at Zafarana, changing the cost of production with +/- 1.4 piaster/kWh. The development of the Gulf of Zayt windfarm site as shown in the

LRMC-supply curve in this report, advances the year of break-even by four years to 2008, whereas Hurghada-type wind sites are not economically viable until the year 2020, a postponement of break-even by eight years.

- On the *economic benefit side*, fuel savings represent more than 80% of economic value. The *price of crude oil* defines the LNG price, and through this, the netback value of saved gas consumption at the power stations. A price of US$26 (+24%) advances economic break-even by three years and reduces the cost of production by 1.4 piaster, a price of US$16 (-24%) increase the cost by postpones economic break-even beyond the year 2024.

Table 11: Sensitivity of Results to Variations in the assumed Values for key Parameters

SENSITIVITY OF MAIN ASSUMPTIONS	Break-even year	Ec.Prod. Cost 2012
Zafarana – **BASE CASE** (no deduction of CO2-revenue!)	2012	11.2
CHANGE FROM BASE CASE		
Gulf el Zayt wind regime (+11% higher output per MW) Hurgada wind regime (-11% less output per MW)	+6 years 8 years	-1.4 +1.4
Thermal plant efficiency: 40-48% instead of 33-43%	+7 years	n.a.
Price of CO_2 certificates: US$0 instead of US$4	+5 years	n.a.
Netback value of LNG: Oil price US$26 instead of US$21 Netback value of LNG: Oil price US$16 instead of US$21	 never	n.a. n.a.
No land lease	-2 years	-0.5
No import duty	(-1 year)	(-0.2)
Productivity increase: 2%/year until 2012 instead of 3.5%	+3 years	+0.7
Year 2004 cost investment (and onwards) +11% higher	+4 years	+1.0

Next in importance are:

- On the economic benefit side, the *choice of correct reference power plant* to calculate the impact of windfarm output on electricity production. The base case assumption is that only *medium-load and peak load plants* are affected by the variations in windfarm output: the *average fuel consumption of steam turbine plants* is used to calculate the fuel savings. The alternative is to assume that fuel savings equal the *average fuel consumption of thermal power plants*, a mixture of *70% steam turbines and 30% CCGT-plants*. That assumption, which affects also the CER-value, postpones the break-even year by seven years to 2019.

- Whereas the cost of production figures in table 13 do not deduct the *revenue per kWh from sales of CO_2-certificates,* the year of break-even figures include the impact of CER-sales. Without the CDM-potential, the break-even year is postponed five years to 2017.

The *other parameters*, ranked by importance are:

- The year 2004 economic cost of investment is estimated at US$ 820/kW. This estimate, made by NREA in March 2003, is too low if the US$/ Euro exchange rate in 2004 is below 1. Due to the need for soft loan financing, the turbines would come from Spain Germany, Denmark or Japan. It will not be possible for turbine suppliers from these countries to lower their prices expressed in Euro to match the decline in the US$-exchange rate. An increase in the level of investment by 11% increases the cost of production in 2012 by 1.0 piaster and postpones the economic break-even year four years to 2016.

- A reduction in the assumed annual *productivity increase of future windfarm technology* during 2004-2010 from 3.5% to 2% would increase the cost of production in 2012 by 0.7 piaster and postpone economic break-even two years to 2014.

- The 2% of electricity revenue *fee for the land lease* increases the cost of production by 0.5 piaster per kWh, its elimination during the "non-commercial period" would advance the year of break-even by two years to 2010.

- The removal of the *import duty* affects the financial cost of production by 0.2 piaster/kWh, advancing the year of break-even by about half a year. (Since it is not included in the economic cost of production, the year 2012 remains unchanged)

Finally, jumping to the financial analysis in chapter 5, one will note that the *assumptions concerning the financing package* represent the largest uncertainty surrounding the future of Egyptian wind farms. Different financing packages let the Investor Cost of Production per kWh for a Gulf of El Zayt site vary between EGP0.12 (soft credit financing) to EGP0.28 EGP per kWh (financing terms available on the present domestic capital market). No technical or demographic parameter has an effect of the same magnitude.

Overall, the base case assumption is robust: the production forecasts by NREA are conservative and based on excellent wind data; the oil price of US$21 reflects the average price during the last 130 years; the choice of steam turbines as reference plant is correct; the CO2-price is unlikely to fall much below US$4; and the productivity forecast of 3.5% is lower than the rate achieved during the 1990s of 5%, and the annual 8% rate achieved during the 1980s.

3.5 Does it make Sense to start-up the 3500 MW-Program before the Year of Economic Break Even?

Is it economically rational to start-up the windfarm investment program before the economic break-even year?" What would the rational position of Egyptian policy makers and of donors look like?

The *economic rate of return* on the 3500 MW windfarm investment program for the 2004-2024 period is *10-11%*; during the "non-commercial" years returns are below, and during the years after economic break-even above this level. A relevant question, therefore, is whether the economic rate of return to Egyptian society can be increased by postponing the implementation of the investment program until the economic break-even period?

From the economic rate of return point of view, the rational position of Egyptian Government would be to agree to the implementation of the program during the "non-commercial" period if two conditions are fulfilled:

1. The use of donor funds for windenergy has no or insignificant opportunity costs to Egypt in terms of reducing the availability of donor grants for other development projects having a higher economic rate of return than windfarm projects.

2. Donors are willing to subsidize the difference between the economic cost of windfarm production and the economic value of the avoided cost in thermal power production.

If the two conditions are fulfilled, Egypt reaps, during the non-commercial period, a 10% economic rate of return on windfarm investments and gets additional non-monetized benefits from increased employment, foreign exchange savings, and from strengthened national windfarm know-how, which has long-term value for the economy. Both conditions seem to be fulfilled.

The opportunity loss for Egypt of using donor soft loans for windenergy projects is close to zero. The crowding-out impact on soft-financed projects in other sectors is modest. Since donors allocate their soft loans to individual countries in the form of indicative targets, increased demand for soft loans in one country can usually be accommodated by a transfer of non-used indicative funds from a country not using its full quota. Even if there is a crowding out impact, it is not certain that the alternative projects would have had a higher economic rate of return than windfarms; assuming this shows lack of confidence in the prioritization process of the Egyptian Government.

The bilateral donors – Denmark, Germany, Spain, Japan – have for years supported windfarm investments in Egypt as a source of sustainable energy supply believing that there is a mass market for the application of that technology in Egypt in view of the country's large wind resources. Since that perspective remains unchanged, it would illogical for donors to cut down on their support just as the previous efforts are leading to success. Although ODA-cofinancing of CDM projects gives donors no ownership rights to project CERs, a new criterion is that *the ODA-subsidy per saved ton $C0_2$-emission is reasonable*. In 2004, the economic cost-benefit gap (without deduction of CER-revenue) is 4.8 piaster/kWh, equal to US$ 18 per ton CO_2, (a price of US$4 per ton $CO_2$1.1 piastre per kWh),.[31] Is that within the acceptable range for donors?[32]

Most likely, the answer would be yes. Table 12 indicates previous political willingness in Denmark to pay the subsidy-support cost of projects implemented in Denmark. In a recent change towards a more cost-conscious strategy, the Danish Government set the cut-off rate for accepted support-costs of domestic investments in CO_2-reduction projects at DKK 150 = US$23 per ton CO_2; CDM-, JI-projects and quota-purchases are to be used for the rest needed to reach the Kyoto-target. KfW's policy is to support the sur-cost of "environmentally friendly projects", if it is below €10 per ton CO_2. As the subsidy cost already in 2007 is down to US$12, and the cost paid by the soft loans is reduced by the CER-revenue it should be acceptable.

Table 12: Danish Government Policy Willingness to Pay for CO2-Reductions. US$ per ton CO2

Danida Mixed Credits	**Cost of Domestic Investments in CO2-Reduction to reach -21% Kyoto Target**[1)]		
Feasibility Study Shadow Prices for CO_2	Replacement of coal by gas in power plants	Offshore Windfarms	Replacement of coal by biomass in power plants
US$20	DKK 150=$23	DKK270 =$41	DKK290= $45

1) Estimates of Danish Energy Agency. DKK-prices converted at DKK6.5 per US$.

[31] The year 2005figure is 4.3 piaster/kWh, 2006 = 3.8 piaster, 2007 = 3.3 piaster, 2008 = 1.6 piaster (US$6/ton).

[32] The overall policy importance is illustrated by the level of the proposed penalty charges of the EU's CO_2 emissions trading market; they increase from €40 per ton of $C0_2$ in 2005 to €100 per ton in 2008. The Netherlands CERUPT pricing is between €3.3-5.5/CER

4 MACRO-IMPACTS OF A 3500 MW INVESTMENT PROGRAM

4.1 The Foreign Exchange Impact of Wind-Generated Electricity

The devaluation of the Egyptian pound since 1998 made policy makers in Egypt very sensitive to the foreign exchange impact of projects in general and of foreign direct investment (FDI) –projects in particular. The foreign exchange impact of the windfarm program is analyzed below.

4.1.1 Components determining the Foreign Exchange Impact

On the input side, wind farms consume foreign exchange through:

- the import content of the investment in the wind farm;
- the import content of expenditure on O&M during the lifetime of the farm.

Through their electricity output, wind farms generate foreign exchange through:

- the revenue from the sales of CO_2-certificates on the international market;
- the netback value of increased LNG supply for exports;
- the import content of saved investment in thermal power capacity;
- the import content of saved expenditure on non-fuel O&M at thermal power plants.

4.1.2 Import Content of Windfarm Investment and O&M

The economic cost of production of windfarms, see table 2 page 18, is very investment intensive.[33] The cost assumptions in this report lead to a year 2004 14%/86% split between the share of O&M and the cost of investment in the cost of production, changing by 2024 into a 17%/83% split, as the productivity increase in the cost of investment is higher than for O&M costs. The share of O&M is lower than seen in international projects, where a 70%/30% split is often seen. Some cost elements, such as annual lease/user charge payments for substations set up by the transmission company to connect wind farms are not included as a cost in this report.

Table 13 summarises the assumptions and the end-result of these in terms of import-content and import expenditure per kWh. Due to the importance of the cost of investment, the import content of O&M costs is insignificant for the foreign exchange impact. The upfront investment consists of between project development cost, WT supplier contract and civil & electrical infrastructure. Project preparation, amounting to 4 percent, is a purely national business; the import content of that cost component is zero. The WT-supplier contract, amounting to 81 percent, comprises the cost of the towers, which are manufactured in Egypt, local transport of material to the site; site visits by foreign staff during construction as well as monitoring and maintenance services during the warranty period. The import content of the supplier's contract is, therefore, estimated at 80% for a

[33] Economic cost is used instead of financial cost, because import duties and financial costs are all purely domestic cost items with no impact on imports.

2004 wind farm. Over time as the investment program expands to make more national manufacturing viable, the import content is assumed to drop to 50% by the year 2004. The civil and electrical works, which account for the last 15 percent, are done by Egyptian construction firms; due to use of some imported material, the work may have an import content of 10%.

Table 13: Import Content of Windfarm Production, Years 2004 and 2014

	Year 2004	Year 2024	% of sub-total
Import Content of Investment	86%	83%	
- WT supplier contract	80%	50%	81%
- Project Preparation	0%	0%	4%
- Civil and Electrical Infrastructure	10%	10%	15%
Sub-total:	66%	42%	
Import Content of O&M	14%	17%	
- Consumables and overhaul investment	80%	50%	52%
- All other costs	10%	10%	48%
Sub-total:	46%	31%	
TOTAL IMPORT CONTENT	64%	39%	
Economic Cost of Production, piaster/kWh	14.8	8.8	
Import Content of Production, piaster/kWh	9.4	3.4	

The import intensive cost items in O&M are overhaul investments and consumption of spare parts, which together make up 52% of the estimated cost of O&M. Since the import content of consumables is linked to the manufacturing share of investment, the same percentages apply Altogether, windfarms established in 2004 are deemed, during their lifetime, to cause an import expenditure of 9.4 piaster per kWh, falling to 3.3 piaster for a new windfarm in 2024.

4.1.3 Foreign Exchange Impact from Savings in Thermal Power Production

The capacity value of windenergy for the 30%/70% mix of CCGT-plants / steam turbine plants is equal to 2.4 piaster per kWh, with an estimated import content of 65%. The savings in variable non-fuel O&M are estimated at 0.003 piaster per kWh with an import content of 40%. Adding the value of increased LNG-exports due to gas savings at the thermal power plants gives a total foreign exchange savings from reduced thermal power production of 9.7 piaster for a year 2004 windfarm and of 7.5 piaster/kWh for a year 2024 windfarm.

Table 14: Foreign Exchange Impact of Production from replaced Thermal Power Production

Thermal Power Production	2004 plant	2014 plant
Capacity value piaster per kWh WT-output	2.4	2.0
Import content of saved investment in capacity	65%	65%
Saved import expenditure on thermal capacity	1.6	1.3
Saved non-fuel O&M piaster per WT-kWh	0.003	0.003
Import content of non-fuel variable O&M	40%	40%
Import expenditureCost of O&M per kWh,	0.0011	0.0011
Value of gained LNG-exports, piaster/kWh	8.1	6.2
TOTAL foreign exchange cost of thermal power	9.7	7.5

4.1.4 Net Foreign Exchange Impact of Windfarm Production

The net foreign exchange impact shown in table 15 shows that w*indfarms established in 2004,* have during their lifetime of operation *a slightly positive foreign exchange impact of 1.6 piaster per kWh* of wind-generated electricity. The higher productivity gains of future new *windfarms compared with productivity gains in thermal power increase the foreign exchange savings to 5.0 piaster per kWh* of windfarm electricity.

Table 15: Net Foreign Exchange Impact of Windfarms, piaster per kWh

	2004 plant	2014 plant
1. Import content of Windfarms, piaster/kWh	**(9.4)**	**(3.4)**
Import content of investment, piaster per kWh	(8.4)	(3.1)
Import content of O&M, piaster/kWh	(1.0)	(0.4)
2. Foreign Exchange Saving Thermal Power	**9.7**	**7.5**
Import expenditure per kWh due to investment	1.6	1.3
Import expenditureCost of O&M per kWh,	0.0	0.0
Value of lost LNG-exports, piaster/kWh	8.1	6.2
3. Revenue from sales of CO2-certificates	**1.3**	**1.0**
4. Foreign exchange saving from windfarms	**1.6**	**5.0**

The numbers in table 15 overestimate the true foreign exchange impact of windfarms, because they do not take into account neither (i) that some of the foreign exchange benefit from the netback value of exported LNG is siphoned off as increased profits to the foreign joint-venture partners in gas extraction in Egypt, nor (ii) that time lags reduce the NPV of the foreign exchange savings: saved natural gas consumption at thermal power plants is not exported “immediately” in the form of increased LNG-exports, and the savings in investment in new thermal power capacity do not occur in the year, when new windfarm capacity is established.

The foreign exchange impact depends on the size of the program. A single windfarm has zero impact on LNG-exports and on investment in new capacity of thermal power. The implementation of a 3,500 MW program, on the other hand, has an impact close to the one estimated in the table.

4.2 Employment Impact of Windfarms per MW installed Capacity

Windfarms have little negative impact on the employment in thermal power. Some labour is saved in daily maintenance and some in the replaced construction of new thermal power capacity.

The team, which prepared the Force 12 report, estimated the employment impact of windfarms at 35 man-years per installed MW windfarm. This worldwide average includes employment in windturbine manufacturing (WT-manufacturers and their sub-suppliers), project preparation, civil and electrical works at windfarms and O&M of windfarms during their lifetime. This means that for individual countries, the impact of a national investment program will be always be lower than the world-wide average, because of the import content in hardware and software.

Labour-intensive components, such as towers, would be manufactured in Egypt, whereas the manufacturing of some high-tech components in Egypt requires competitiveness on the worldwide export market to be feasible. It can be assumed that the employment impact of a large scale program in Egypt would equal 60% of the worldwide average, or 20 man-years per 1 MW windfarm.

The lifetime employment impact of 3500MW of windfarms amounts to 30,000 man-years.

If large scale national investments bring forward an internationally competitive supplier industry, there will be employment spin-off from potential exports of domestically produced windfarm components.

4.3 Impact of the 3500 MW Program on National Power Supply

Table 16 shows the share of a 3500 MW windfarm program in the national supply of power, making the simple assumption that 170 MW are added each year during 20 years.

Table 16: Share in MW-Capacity and in Electricity Production

Share in MW-Capacity and in Electricity Production	2001	2010	2020	2025
Power Capacity connected to national grid, MW	14,773	23,145	39,101	48,702
Total national power demand, TWh	65	115	215	295
Annual growth rate in power demand, 2001-2010 and 2011-2025	6.5%	6.5%		
Wind power capacity connected to national grid, MW	68	1,037	2,652	3,298
Power generation from windfarms fed into the national grid, GWH	268	4,360.4	11,848	15,312
Installed windfarm capacity in % of total generating capacity	0.4%	4%	7%	7%
Windfarm power production in % of national power production	0.3%	0.25%	6%	5%

The 3500 MW windfarm program would in the year 2025 supply 15 TWH per year, which amounts to 5 percent of national *electricity generation*. The *generating capacity* of the windfarms would equal 7 percent of national generating capacity, reducing the need for thermal capacity by about 1000 MW or 2 percent of installed capacity.

4.4 Impact of 3500 MW-Program on National Gas Consumption

By the year 2024, the windfarms will save more than 3 billion cubic meters of gas consumption per year, representing an economic value – the netback value of LNG exports -of US$160 million.

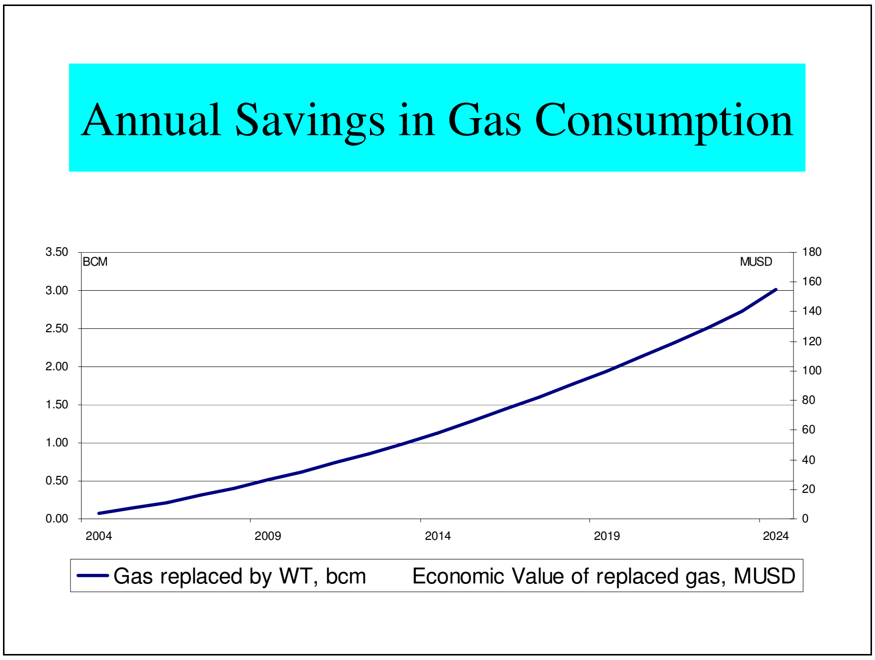


Figure 7: Annual Volumes and Values of saved Gas Consumption at Thermal Power Plants

4.5 Annual State Revenue from Lease of Land to Windfarms

The economic cost analysis is based on the assumption that the state will charge a lease fee equal to 2% of electricity revenue. This provides the state with a steadily increasing lease revenue; leading to an annual income in the year 2024 of EGP 23 million (US$4 million).

4.6 Required Donor Finance for the Non-Commercial Phase

Table 17 shows the level of required donor funding during the non-commercial phase, but using different assumptions than table 16 for the rate of progress in installed capacity. Table 16 assumed that 170 MW would be installed each year, this scenario assumes a lower rate of investment during the non-commercial years, corresponding to the availability of donor funds. In table 17, just 60 MW are installed by private investors in 2004, during the non-commercial period, the annual level of investment increases an additional 10 MW each year during the non-commercial period.

The accumulated level of investment, up to and including the year 2009, amounts to 510 MW installed capacity, representing an investment of US$379 million, not including the cost of import duty, sales tax, interest during construction, working capital, reserve funds, etc. all of which are items that are not included in economic cost analysis. The import duty and sales tax may be suspended during the non-commercial phase, yet, the other cost-of-finance items add 10% or more to the cost of investment of a private investor.

Table 17: MW Investment per Year and Financing Implications of Windfarm Program. US$-million

Need for Donor Grants during Non-Commercial Years						
Windfarm site	**Zafarana**				**Gulf of El Zayt**	
Year	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
New installed Capacity per Year, MW	60	70	80	90	100	110
Economic Cost of Investment, million US$/year	49	55	61	66	71	76
Annual Output, MWh per MW	3,942	3,942	3,942	3,942	4,380	4,380
Economic Cost of Production, Piaster/kWh	14.8	14.1	13.5	13.0	11.2	10.7
Cost of production minus CO2-revenue, $4/ton	13.6	13.0	12.4	11.9	10.1	9.7
Economic Value of Benefits, Piaster/kWh	9.8	9.8	9.7	9.7	9.6	9.6
Required subsidy, Piaster/kWh	3.8	3.2	2.7	2.2	0.5	0.1
Subsidy in million EGP/Year during 20 years	9.0	8.9	8.6	7.9	2.3	0.6
NPV of Required Subsidy during 20 Years, EGP	76.4	76.2	73.0	67.0	19.3	4.8
NPV of Subsidy in million US$	13.6	13.6	13.0	12.0	3.4	0.9
Subsidy in % of Investment	28%	25%	21%	18%	5%	1%
Subsidy in US$/ton CO2 (after CER-payment)	13.7	11.7	9.9	8.1	1.9	0.4

The results in table 17 are encouraging in terms of making donor-financed private investment a realistic option in Egypt:

- *The grant element in Mixed Credits of 35%* - reduced to 30% once the mixed credit has been channelled through the local bank to the project developer – *would nearly be sufficient to make private investments in windfarms commercially viable* if internationally competitive financing terms were available on the Egyptian market, and if investors were able to sell CERs at US$4 per ton. The required investment subsidy based on economic cost is 28% in 2004, falling to 5% in 2008, the last "non-commercial year".[34]

- The financial cost of investment for the project developer is higher than the economic cost of investment; making it necessary to provide an investment subsidy larger than the 28% rate shown for the year 2004.

- *The cost of the subsidy, coming on top of the CO_2-revenue of US$4/ton CO_2, is US$13.7/ton CO_2 in 2004, which is reasonable for donors*, since it declines in the following years.

- *The US$ 60 million per year in terms of soft loans, should not pose a major financing problem for donors.*

[34] The grant element is calculated as the NPV of the difference in annual interest payments paid for the soft loan and what would the recipient would have to pay for a loan at the prevailing international rate of interest. The local bank adds an on-lending margin of 2-4% to the zero percent rate of interest paid by the soft credit plus some fees.

- The turnkey-contract[35] financed by the soft loans comprises turbines, civil and electric infrastructure, warranty; while the investor through his equity finances the cost of project preparation, land clearing, interest during construction, working and reserve capital. The assumption results in an *80%/20% debt/equity split* which is higher than the upper gearing ratio of 70/30 that private banks would be willing to accept. The investor, therefore, will not get a domestic loan to fully repay the soft loan, but raise additional equity for this purpose.

OECD rules allow a soft credit to be given as long as the project on normal bank loan terms is not a commercial investment opportunity. Once windfarms reach the commercial phase in the years 2009-10, the mixed credits can no longer be given to windfarm investments in Egypt.

[35] Also called EPC-contract – Engineering, Procurement, Construction.

5 ENERGY PRICING BARRIERS TO INVESTMENTS IN WINDFARMS

5.1 Introduction

5.1.1 Financial Discount Rate and Economic Discount Rate

In this report, the *financial discount rate* and the *economic discount rate* are both fixed at *10 percent*, and both are used in project analysis for a 20-year windfarm period of operation.

The analytical reason for using the same rate is that differences in the economic and the financial costs of production, using this approach, show *the impact per kWh of wind-generated electricity of the distortions in market prices that are introduced by taxes on windfarm inputs and by subsidies on inputs used in thermal power production*.[36]

Differences between the market prices and the economic prices represent market imperfections that require corrective action by the Government if an economically more optimal result is to be reached on the energy market.

5.1.2 Energy pricing barriers in Egypt

The absence in Egypt of "normal" energy market conditions creates cost-barriers for private investments in windfarms that come on top of the economic cost-benefit gap.

Energy pricing policy in Egypt increases the gap between the benefits and the costs of windfarm production:

(i) *gas subsidies* to thermal power plants reduce the financial value of avoided costs in thermal power production below their economic value and

(ii) windfarm components are subject to *import duties* and *sales tax*, which increase the price of windfarm investments above the economic cost on.

5.1.3 The deadweight loss of subsidies

Taking 100 piaster out of the left pocket of a person through taxation and returning 100 piaster in subsidies into his/her right pocket, imposes economic costs on society in the form of "*transaction costs*" (cost of the manpower and other resources used in implementing the transactions) and "*economic distortions costs*" (the economic behaviour of the person is different from what it would have been, if the transactions had not been carried out). The latter can be a warranted positive

[36] The financial cost analysis includes working capital in the initial cost of investment, the economic analysis does not. The difference in cost is negligible, and therefore ignored in the following comments.

effect, as when an industry subject to CO_2-taxation gets the tax revenue back as subsidies to energy saving investments (effect = reduced energy consumption). Usually it is negative; the level of electricity saving investments in Egypt, for example, is below the economic optimum because the gas subsidy to thermal power production reduces the price of electricity.

The deadweight costs of subsidy programs can be considerable. The Danish Ministry of Finance estimates the cost in Denmark at 15% of the value of subsidies. In national economic cost-benefit calculations, this cost is deducted from the value of the economic benefits of supported activities and technologies to show the net economic benefit.

In Egypt, the deadweight loss of the subsidies will be at least as high. Subsidies introduced in one end of the system tend to have a snow-balling (or domino) effect on price setting in other ends of the system, as other subsidies are introduced to compensate for unwanted side effects of the former.

5.1.4 PPA-tariff a profit maximising single buyer would pay

The tariff, which a least-cost oriented system operator / single buyer[37] would be willing to pay for windfarm output, is equal to the avoided financial cost of thermal power.[38]

5.2 Import Duty and Sales Tax on Capital Investments in Windfarms

5.2.1 Impact of import duty and sales tax on windenergy

The *8% import duty* on imported components and the *10% sales tax* on investment items increase the cost of windfarm production by 0.4 and 0.7 piaster/kWh, respectively.

Investments in thermal power plants are subject to the same duties and taxes[39]. Yet, because of the *higher capital intensity of windfarm production*, and due to the fact that *thermal power plants do not pay sales tax on their purchase of natural gas*, the cost of production of windfarms is artificially increased compared to the cost of thermal power production.

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[37] The structure and the market rules of the future power system regime in Egypt are still under discussion. It is here assumed that the single buyer regime prevails in the foreseeable future. A "perfect market", would, however result in the same avoided cost PPA-tariff.

[38] The present market structure in Egypt is characterised by a monopoly on the demand side, where EEHC as holding company controls national transmission and system operation, all eight regional distribution companies and five generation companies. On the supply side; new IPPs, mainly BOOT-schemes, sell their output to the single national buyer, EEHC's Transmission Company, on long-term PPAs. In this structure, and in the absence a regulatory scheme securing premium payments to "green electricity", the system operator/national transmission company has no incentive and no obligation to pay a price for windpower, which is higher than the *marginal financial costs of replaced power production in the power system*. EEHC as system operator will be tempted not to assign any capacity value to windfarms as the additional capacity of a new windfarm in a given year has no here-and-now implications for investments in thermal power capacity. The "avoided cost" attitude came out clearly during the tough negotiations between NREA and EEHC for the PPA for Zafarana II. In the end, a 10 piaster per kWh-tariff was agreed, but without a direct inflation adjustment formula. It was only agreed that the price could be revised from time to time.

[39] Yet, all references in this report to the cost of thermal power are net of import duty and sales tax.

Government energy policy is to promote, not discriminate, investments in renewable energy, it would make political sense for NREA/MOE to prepare a proposal for Government / Parliament for the abolishment of the import duty and the sales tax.

5.2.2 Fiscal impact of removing import duty and sales tax on windfarm components

A working group established to prepare a proposal for removing the import duty and sales tax, will, as an inevitable outcome of its analytical work, point out to policy makers:

1. The *fundamental policy contradiction* between, on the one hand, using fuel subsidies and reduced profits of state-owned transmission and distribution utilities[40] as means to limit the final consumer price of the output, electricity, and, on the other hand, impose duties and taxes on inputs used for electricity generation.

2. The *implications of state ownership of windfarm land for Government revenue generation from taxes and duties* on windfarm components: what the Government gains in revenue from taxes and duties is lost in reduced income from the leasing fees for windfarm land.[41]

The conclusion of the above is that *the sales tax and import duty on windturbines do not raise any net-revenue* for the state budget: what the Government gains in revenue at one end of the electricity supply chain, is lost at the other.

The net impact of the policy is a *deadweight loss* on the national economy, which, as a minimum, amounts to 15% of the revenue from the sales tax and import duty.

5.2.3 Import duty and maximisation of national production content

To *raise revenue* for the national budget is one of the objectives for import duties. Another is to *promote domestic manufacturing production and employment generation*. How will a removal of the import duty on wind-turbine components affect this objective?

The primary objective of the implementation of the large scale national windfarm program is to expand the national generation portfolio with a new cost-competitive source of generation. The essential sub-objective is employment creation, which calls for the maximisation of the national production content, as long as it is or can be made price competitive with foreign production.

What is the potential for cost-effective domestic production and how can it be maximised?

In some components Egyptian industry enjoys a *natural cost advantage*. The manufacturing of towers, for example is a case in point. There are little economies of scale in tower manufacturing,

[40] The policy of keeping electricity retail tariffs constant during the last ten years, while cost of supply increased has reduced profits and undermined the financial strength of EEHC.
[41] The higher the cost of windfarm production, the lower the economic rent of windfarm land.

the technical know-how is locally available while high costs of overseas sea transport give local production a cost advantage. This leads foreign turbine suppliers to look for domestic manufacturers without help of Government intervention or imposition of import duties.

In the manufacturing of other components, Egypt may not have a natural cost advantage; but *be potentially able to manufacture the components at the same price as imported components*, provided that a conscious effort is made to transfer the necessary know-how to Egypt, and to develop local capabilities. In this case, Egyptian manufacturing will neither lower nor increase the cost of windfarms, but the national economy as such will gain from the national value added.

Figure 8 makes the point that *the size of the national market* is the essential determinant for the national production content of "late starters", like Egypt, who have catching-up to do in terms of building up an internationally competitive domestic industry. Setting up national blade production, for example, requires a minimum initial market size to justify the investment in the production equipment, while know-how intensive products, like specialised software and electronic equipment need a certain market size to attract domestic talent into its development. In addition, the latter may depend on the ability to export.

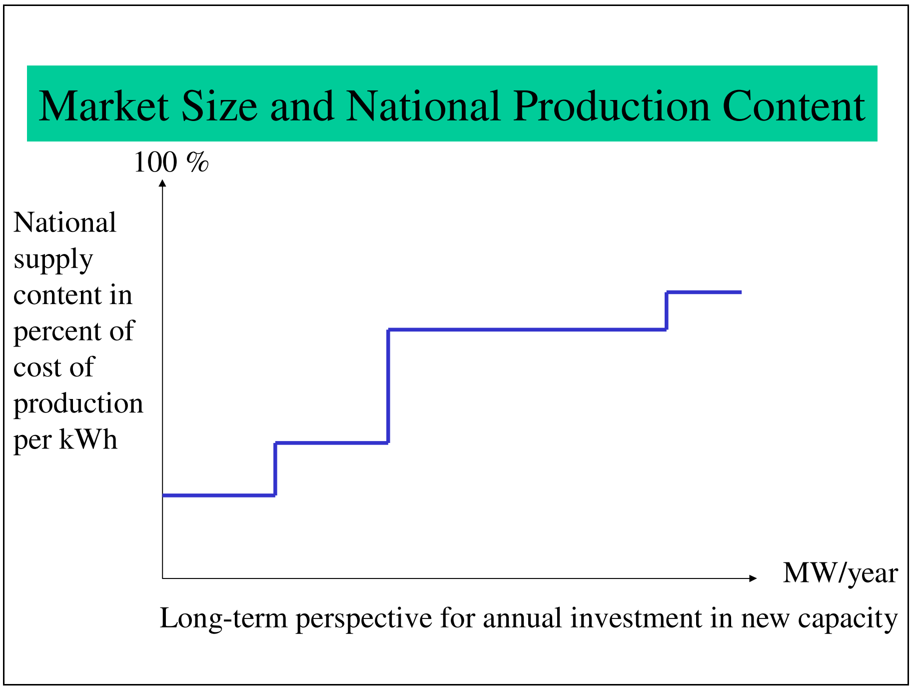

Figure 8: Size of Market and National Production Content of Windfarm Investments

The policy conclusion to be drawn from figure 8 is that the most important instrument for promoting national production content is to *create a long term large-scale market for turbine suppliers through an appropriate regulatory and financing framework.*

Since the size of the market is the essential determinant for national production, *the import duty is a very ineffective instrument*. It increases not only the price of components that can be manufactured competitively in Egypt (where only in marginal cases it will make a difference for domestic production), but also the price of components, which will not be manufactured in Egypt as long as the market is too small, as well as others, that never will. The import duty, by increasing the cost of windenergy, reduces the size of the level of annual investment in windfarm capacity, which is counterproductive to the objective of national employment generation.

An instrument, which simultaneously expands the market for windenergy and increases national production content, was used successfully in Spain to develop an internationally competitive windturbine industry. The regional Governments in wind-resource rich regions offered an *extra payment to windfarm operators who installed locally manufactured windturbines*. This motivated foreign turbine suppliers, interested in gaining market share, to set up local production facilities in the region either through joint-ventures or through fully self-owned subsidiaries.

India used a different approach. The government fixed and announced *pluri-annual, gradually increasing targets for national production content* as a condition for giving windturbines access to the special incentives given to windfarm investments. This approach requires ability to identify areas, where national production, although its does not have a natural cost advantage, can be made internationally competitive through a concerted development effort.

5.3 Subsidized Gas Prices reduce the Financial Value of Avoided Costs

5.3.1 Size of the gas subsidy

Figure 9 summarises the financial and economic values of gas at the power plants.

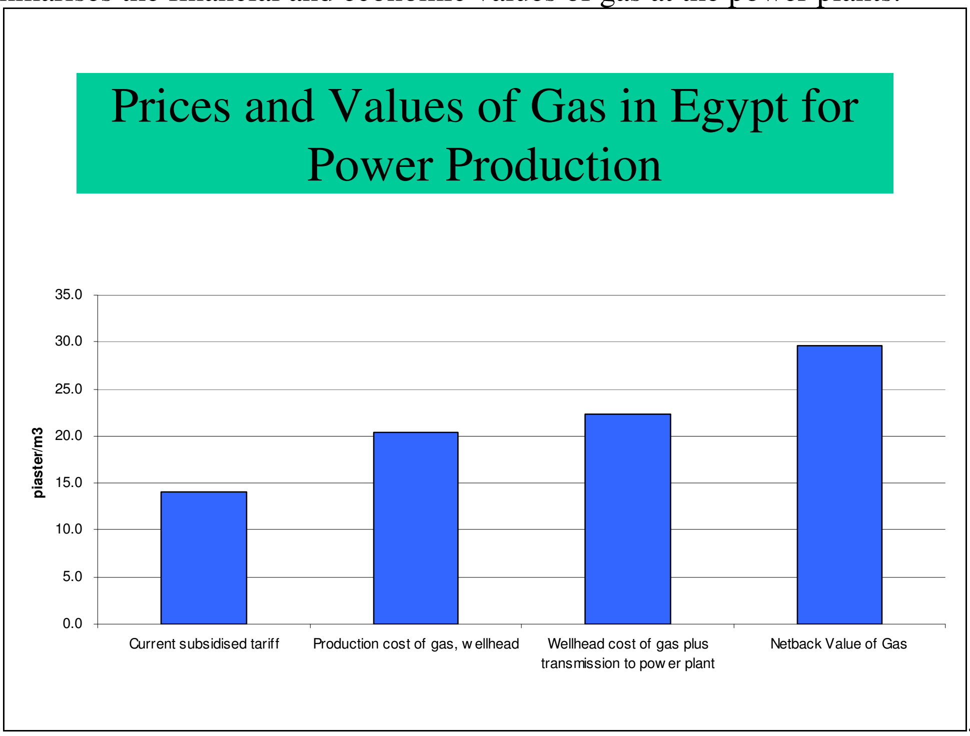

Figure 9: Financial and Economic Prices of Gas consumed by thermal Power Plants

The subsidy to a product is equal to the difference between the market price of the product and its economic price. Table 18 shows the size of the subsidy given to electric power production as a function of the reference price for gas.

Table 18: Level of Gas Tariffs and Size of Subsidy per kWh of generated Electricity

Gas Subsidy for Thermal Power Plants	Price of gas piaster/m3	Cost of gas, piaster /kWh of electricity	Subsidy per kWh
Steam Turbine Power plant price, 2003	14.0	3.4	3.8
Power plant price, 2004, financial cost coverage	22.3	5.4	1.8
Power plant price, 2004, economic cost coverage	29.6	7.2	

Compared to the economic price of gas ("netback value" of LNG exports to Europe) of 29.6 piaster/m^3, the *year 2003 power plant gas price of 14 piaster/kWh* represents a subsidy of 3.8 piaster per kWh; while the *"domestic cost coverage tariff" of 22.3 piaster* (used in this report for the year 2004 financial cost calculations), equals a subsidy of 1.8 piaster per kWh.

5.3.2 Resource rent of gas in Egypt

The price difference of 7.3 piaster per m3 of gas between the netback value of gas and the domestic cost-coverage price of gas represents the *"resource rent"* of natural gas in Egypt: the difference between the free market price of a primary material and its cost of production.

5.3.3 Social impact of transferring the economic rent to power consumers

The subsidized gas tariff charged to thermal power plants transfers the economic rent of gas to electricity consumers. Charging power plants and other gas customers the full economic price of gas is economically more efficient; [42] but, politicians believe that the gas subsidy has a positive social impact: it lowers the price of electricity, an essential good, which all households need.

This view is too narrow. It looks only at the *first order effect*[43]: the reduction in the price of energy paid by Egyptian gas and electricity consumers. This has a positive social effect on the poorest households, but depending on how the lifeline tariff is constructed, it may have high spill-over costs by transferring subsidies also to more well-to-do households.

Once we take into account the *second order effects*[44] of foregone tax revenue on social equity, the picture becomes less positive. By not taxing the resource rent of gas, the Government must:

- (i) get the "lost" revenue either by increasing other duties and taxes;
- (ii) and/or cut down on public expenditure;
- (iii) channel compensating subsidies to other energy suppliers, such as wind farms, to maintain their competitive position vis-à-vis gas fired generation.

[42] The resource rent of charging the full economic price can be channelled into the public budget by introducing a variable tax on gas consumption, which is linked to the difference between the netback-price of LNG and the domestic cost of production price.
[43] The green arrows in figure 10.
[44] The red arrows in figure 10.

The social impact of the second order effects depends (i) on what taxes are increased and their incidence on low-income groups, (ii) on the specific kind of expenditure that would have been expanded if the economic rent taxation revenue had been raised – whether it is health, social insurance, education, etc. - and their impact on this on low-income groups; and (iv) on how the economic deadweight losses imposed by the price distortions affect low income groups.

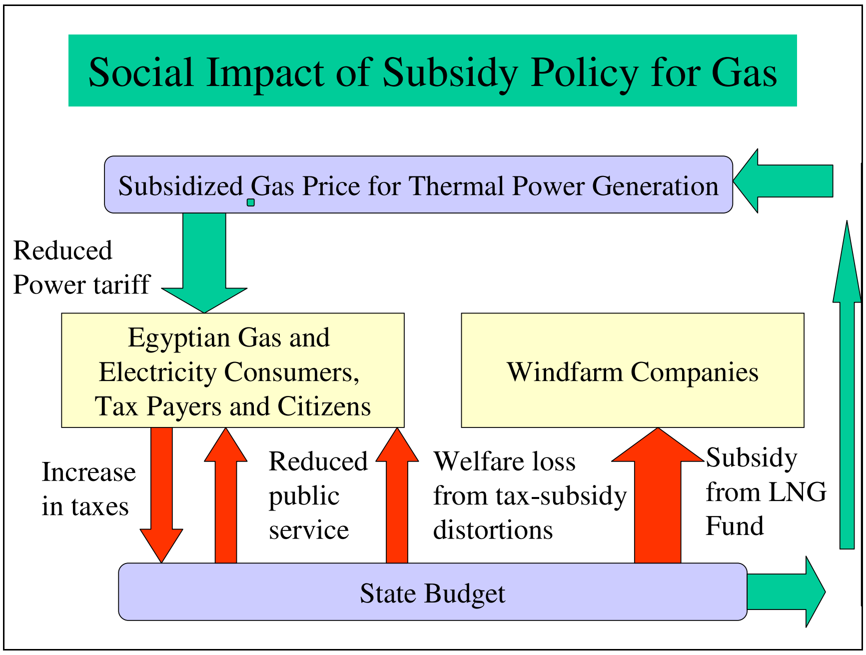

Figure 10: Social Impact of Subsidy Policy for Gas

Whether, the gas subsidy policy has a positive social impact depends on whether the first order (positive) impact is stronger than the (negative) impact from the second order effects of the pricing policy for gas. Nobody knows, the analysis has not been carried out. [45]:

5.3.4 Economic cost of the gas subsidy

The economic costs associated with the gas subsidy policy are listed in table 19:

1. The low-cost price signal distorts the investment and consumption behaviour of consumers leading to non-optimal resource allocation (non-optimal level of consumption).
2. To off-set, or mitigate, the distorting effects of the gas subsidy on national resource allocation, the Government sets up other subsidy schemes, such as the proposed Renewable Energy Fund discussed in section 5.5.5. These schemes have administrative costs.
3. Alternative taxes, introduced to raise the revenue which a resource rent tax would have provided, are almost certainly less efficient economically, meaning that they have some distorting effects on the economy.

[45] Even if a social impact analysis were to be commissioned by the Ministry of Finance, the result of the social-impact analysis would still be debatable, as it depends on the validity of the "counterfactual argument" (theory which tries to give hypothetical answers to the question "what would have happened if not this or that event had occurred or this or that policy decision had been taken"). Nobody can really tell, which tax is raised or what expenditure is cut down, because the state budget does not get the revenue which a gas resource rent tax would generate?

Table 19: Economic Costs of Subsidies to Gas Consumption

Effect	Impact	Cost in EGP million per year
1. National gas consumption above the economic optimal level	Reduced LNG exports, loss of foreign exchange income, lost labour creation in energy savings, environmental impact from higher emissions	?
2. Increase in less-optimal taxes	Welfare losses from reduced allocative optimum	?
3. Compensating subsidies to renewable energy and energy saving technologies	Cost of administration for government and for recipients of subsidies	?

5.3.5 Renewable Energy Fund financed by a fee on LNG-exports

Negotiations between the Egyptian Minister for Electricity and the Egyptian Minister for Hydrocarbons (MOP, Ministry of Oil and Petroleum) let to agreement on the establishment of a *Renewable Energy Fund* financed by a small fee on LNG exports. The Fund will provide subsidies to renewable energy technologies, including windfarms. The agreed decision is that the fund will pay windfarms half of the price difference between the netback value of gas exports and the domestic price of gas at the power stations. How this will be done is not yet decided. It could be done either as an up-front payment (the NPV of expected future price differences) or as a fee per kWh equal to 50% of the price difference between the netback value and the price of gas charged to thermal power plants. The latter, output based subsidy, fits better to the income generation profile of the LNG-fee than an upfront investment subsidy.

The LNG-Fund payment can be combined with the full-avoided cost tariff described below.

5.3.6 Internalizing the netback value of gas in the tariff paid to windfarms

For grid connected technologies such as windfarms the administratively easy, least costly and economically most optimal solution is to pay windfarms a tariff, which reflects fully the avoided costs in thermal power. The formula used by the system operator to calculate the avoided cost tariff, would use the netback value of LNG-exports as the shadow price, reflecting the true economic value of gas, instead of the tariff charged to the thermal power stations.[46] The agreed to payments from the Renewable Energy Fund would be paid as compensation to the system operator (single buyer).

The tariff sends the right price signals to all stakeholders – windfarm investors, system operator, and politicians.

In the absence of payments from the Renewable LNG-Fund, the "avoided cost tariff" reduces the "economic rent"– reaping of the electricity consumer by a small amount. Based on the installed MW per year assumptions in table 16, the financial implications of paying an "avoided economic

[46] A procedure for this is described in Chapter 7, section 7.1.

cost tariff" rather than the "domestic cost coverage tariff" are shown table 20. The extra monthly payment of a low-income households consuming 150 kWh per month, amounts to 0.9 piaster per month in 2004 and to 15.6 piaster per month in 2024 when the investment program is completed.

Table 20: Financial Implications of Full Avoided Economic Cost Tariff for Windfarms

	2004	2014	2024
Annual extra payment by System Operator for power purchase	EGP5 million	EGP80 million	EGP219 million
Extra payment per kWh of power consumption in national grid	0.006 piaster	0.066 piaster	0.104 piaster
Monthly extra tariff payment by low-income household, consuming 150 kWh/month	0.9 piaster	9.9 piaster	15.6 piaster

It is clear from table 20 that there are no objective social impact reasons that can justify not to adopt a "full economic value" pricing policy for the windfarm PPA-tariffs.

6 FINANCING FRAMEWORK FOR INVESTMENTS IN WINDFARMS

6.1 Cost of Capital Barrier: Terms and Conditions for Project Finance

6.1.1 Capital market and capital market barrier: definitions

The term "*capital market*" refers to the market for long-term finance, primarily long-term debt (bank loans and bonds) and equity. The capital market in addition comprises associated specialised products such as hedging instruments.

The term "*capital market barrier*" refers to the increase in the "investor's cost of production" due to a national capital market*,* which does not offer investors project finance terms and conditions that are internationally competitive.

6.1.2 Capital market: liquidity and depths of bond and equity issues

The term *liquidity* of the capital market refers to the speed with which one can expect to sell or buy a specific stock of equity or of bonds. Almost all buyers of long-term bonds or of equity expect to sell their financial assets before they reach maturity. Holders of bonds and stock sell to raise cash for alternative investments or for consumer goods. If one can expect to find buyers/sellers within a day of giving notice to a broker, the market is said to be very liquid, meaning that financial assets change hands often. If a buyer or seller has to wait several weeks, the market is illiquid. Lack of liquidity reduces the price of issued bonds and of equity, increasing the cost of capital.

The term *depth* of the capital market refers to the types of financial products that are offered on the market: bonds with different maturities (short term, medium term and long-term), equity from different industries and with different risk profiles (preferred stock, secondary stock), hedging instruments such as derivatives, etc. The depth of the capital market determines the efficiency of price setting: the existence of products with similar profiles allows for benchmarking: by looking at the price of a financial product with a similar risk profile, an investor knows what price to offer.

Securitization is a financial market instrument which converts debt into cash against a discount, thus adding liquidity to long-term loans. A bank, for example, faced with a liquidity crisis, can transfer its windfarm loan portfolio to another institution against a discount in the NPV of the future amortization stream. The buying institution may bundle debt acquired from different sources into one bundle and issue a bond based on the revenue stream of the underlying debt assets.

6.1.3 Cost of Capital and Financial Discount Rate

An investor will in his project analysis apply the *financial discount rate* that reflects his *cost of capital*.

The *cost of capital* in project finance is the weighted average of the price of project debt (loans) and of equity. If project finance is composed of 70% loans at 13% rate of interest and of 30% equity with a 20% after-tax-rate-of-return on equity expectation, the investor's cost of capital is 15.1%.[47]

Under traditional rate of return regulation of power tariffs, regulators in OECD-countries fixed the cost of capital for vertically integrated power utilities or for transmission/distribution companies at between 8 to 12 percent (the low rates reflecting the low commercial risks of a regulated power industry). In view of this, this report uses a 10% financial discount rate, to reflect the cost of capital rate for windfarms operating in a well-functioning capital market.[48]

The difference between the financial discount rate of 10% and the investor cost of capital of more than 15%, therefore, reflects the *financial cost of the imperfections of the capital market* in Egypt.

6.1.4 Financial cost of production and investor cost of production

The term *financial cost of production* refers, in this report, to the cost of production, which results from applying the 10% financial discount rate to the stream of investment and O&M costs during the lifetime of the project and dividing it with the NPV of annual output-quantities.

The *investor's cost of production* is the price/tariff, which gives the investor sufficient revenue to repay the project loans, cover his operating costs and earn the investor the target rate of return on equity. The required tariff is higher than the financial cost of production, because of the investor's higher cost of capital. In and next on the length of loan maturity and the investor's time horizon.

In countries having a weak capital market, it is essential, when discussing "costs of production"to distinguish between the "*financial cost of production*" per kWh and the "*investors' cost of production*" per kWh in project analysis. The difference is summarized in figure 11.

When the local market offers well-structured project finance[49], there is a close match between the two cost estimates. A windfarm developer operating in Europe or in the USA can get a financing package composed of 20% equity and 80% debt in the form of 15-20 year bonds or bank loans at 6-8% rate of interest. Project developers would expect, as a minimum, to get a 15% after tax rate of return on equity. With these terms, the tariff level needed to secure financial closure will be close to the financial cost of production calculation for the project using a 6-10% discount rate.

In countries with a weak capital market, the difference between the two cost estimates is substantial.

[47] The calculation is a simplification. More precise formulas include the impact of taxation rates: payment of interest can be deducted from taxable profits, equity payment cannot.
[48] However: utilities financed their investments through balance sheet finance, not by non-recourse project finance!
[49] It means (i) that the equity/debt ration adequately reflects the risk of project finance, (ii) that interest rates (and equity rate of return requirements) are set at internationally competitive levels, and (iii) that there is an appropriate match between the length of the maturity on debt and the economic lifetime of the project.

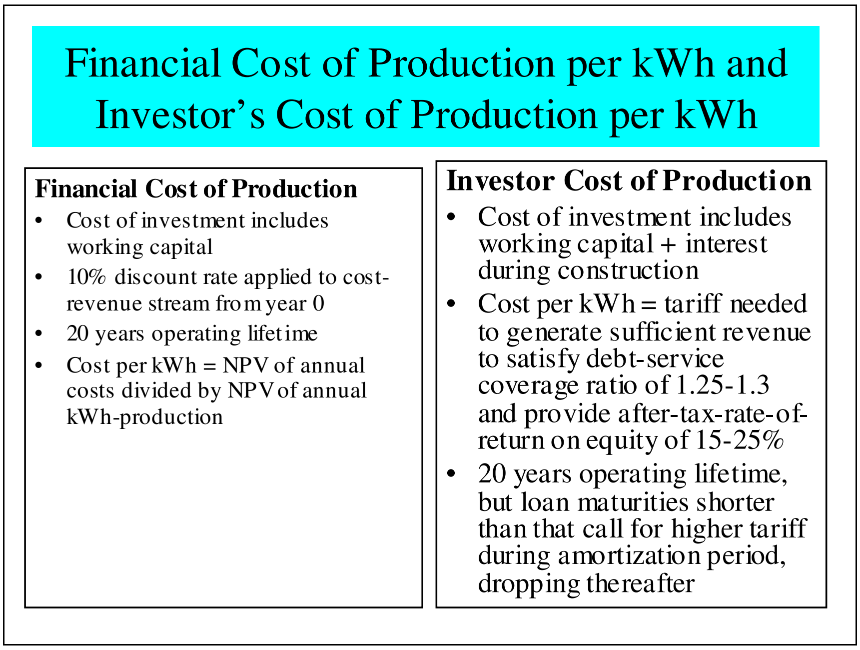

Figure 11: Difference between Financial and Investor Cost of Production

6.1.5 Debt-Service-Coverage Ratio (DSCR)

The *Debt Service Coverage Ratio (DSCR)* is a quantitative measure used by lenders to determine whether a project's prospective net cash flow from operations can support (make timely service payment on) a given amount of debt at the indicated potentially available terms. The debt service coverage ratio is defined as the "cash available for debt service divided by the total amount of debt service".[50] This ratio is used to determine a project's debt capacity.

Normally, banks in their appraisal of requests for project finance insist on a DSCR of 1.25 to 1.3 as a condition to approve a loan. When the debt portion of project finance is down to 50%, the DSCR requirement is easy to fulfil. But at an 80%/20% debt-equity ratio for project finance, amortization payments swallow up a large portion of operating profit.

6.1.6 Choice of wind turbine and cost of finance

The choice of wind turbine impacts on the financial cost of finance. Interest rates used for project financing are linked to the *perceived risk of the chosen turbine technology*. Proven turbines with a minimum two years record of hundreds of turbines in operation get a lower interest rate than new turbine models. In addition to the risk-free base interest, such as Euribor, a commercial bank providing project finance to a windfarm in an EU-country, would demand a margin of around 2½-4%, depending on the type of turbine. Well-known and proven technologies could get 2½%, newer (and, normally, larger) turbines would pay a margin of up to 4%.

[50] The DSCR is calculated for a given *debt service period* and for *individual years*. The annual debt-service-coverage-ratio (DSCR) is "the operating profit after payment of taxes before payment of interest and depreciation divided by the annual amortisation payments (payment of interest plus repayment on principal of loans)".

6.1.7 Regulatory risk: impact on project finance

Regulatory risk increases the *cost of capital* and decreases the likelihood that banks will undertake *non-recourse project finance*.[51]

As long as tariff-approvals in Egypt continue to be dominated by political concerns, there is a strong risk that the transmission/distribution companies signing long-term PPAs with private windfarms either are financially weak or risk being financially undermined by cost increases beyond their control. This entails the risk that a signed PPA at a given time cannot be honored by the purchaser and that a re-negotiation must take place.

The *ERA* is trying to implement a rational power market in Egypt. Yet, at present, most of EEHC's distribution entities are in a financially weak position.

In such a situation, banks and project developers add a risk premium to their loans / equity investments. Banks will be reluctant to finance projects on a non-recourse basis. This prevents new, smaller project developers to the windfarm market; thereby limiting competition.

6.2 The Capital Market in Egypt: Impact on Investor Cost of Production

6.2.1 Conditions for project finance in Egypt

At present, the *national capital market* does not offer project financing on terms, which are internationally competitive:

- The typical private investor insists on *20%-25% after-tax rate of return on equity (RORE).*
- Investors have to rely on *bank loans* for their debt finance. Under the best of conditions, a private investor would be offered (i) interest rate of 13%; (ii) loan maturity of 8 years; (iii) 30% equity-self-finance. Non-recourse lending is unlikely.
- The *bond market* is almost non-existent in Egypt. There are a few corporate bonds of double-A rated companies with a maximum maturity of eight years. The turn-over of bonds is very low; leading to a highly illiquid market. Attempts have been made for several years to launch 20-year bonds for housing mortgages; but so far, without success.
- The *equity market* is small. There are few listed companies and turn-over of equity is low.
- *Securitisation* is not offered in Egypt.

[51] Non-recourse means that the project itself – its cash-flow – is the only collateral for the loan. Balance-sheet-finance means that the bank lends against the overall financial strength of the company; the total assets of the developer are collateral.

6.2.2 Impact of short maturities on upfront PPA-tariff

Maturities of bank loans shorter than the 20 years economic lifetime of windfarms push up the annual amortization payments, and through this the upfront tariff needed to provide an acceptable DSCR during the initial years until the major loans are repaid. From then on, although the cost of O&M increases during the second half of a windfarm's operating lifetime, the revenue requirement drops radically.

The relative importance of the DSCR-condition and the RORE-condition is illustrated in table 22:

1. *The shorter the length of maturity, and the lower the equity share, the more important is the DSCR-restriction*. The 1.25 DSCR-condition defines the minimum tariff when the maturity is 10 years, whereas the RORE-condition defines the minimum tariff when the maturity is 20 years. In row 1, the case of an 8-year loan, the DSCR-condition imposes a tariff of 27.0 piaster/kWh, which is more than sufficient to satisfy a 15% RORE-condition! In the case of the 20 year loan, the 19.6 piaster per kWh dictated by the DSCR-restriction is barely sufficient to satisfy a 15% RORE condition.
2. *The higher the rate of interest, the more important is the DSCR*-restriction. At the low rate of interest of 8%, the DSCR-tariff is totally insufficient to fulfil the RORE-condition.

Table 21: Loan Maturity and Tariff per kWh required to reach DSCR of 1.25

Loan Conditions and Terms	*Piaster/kWh*	*ROR on Equity*
13% rate of interest, 80%/20% debt/equity, 8 year loan	27.0	23%
13% rate of interest, 80%/20% debt/equity, 20 year loan	19.6	14.7%
8% rate of interest, 80%/20% debt/equity, 20 year loan	14.8	11.3%

The cost-of-tariff burden imposed by the initial high cash-flow for debt service can be reduced by a *two-step PPA-tariff*. The tariff would be high during the initial "debt amortization period" and low during the later "post-amortization period". Examples for a two-step tariff exist in other countries, for example, in Denmark, where wind farms get a high tariff for the first X-thousand "full-operating hours" [52]and a lower tariff in the following years of operation.[53]

Other options, analyzed in section 6.3, and more favourable for the system operator, are:

1. To introduce *loans with longer maturities*. Banks in Egypt are willing to give loans with longer term maturities provided that they get a back-to-back loan with a similar maturity from another institution. The relevant institutions back-up institutions would be foreign, such as the World Bank/GEF, KfW, Danida Mixed Credits.

2. To introduce *long-term revenue bond issues* backed by the revenue stream of a windfarm and sell these on the open market to small-scale and/or large scale investors.

3. To *get institutional investors with a long-term placement interest, such as pension funds or insurance companies to invest directly* in windfarms as equity investors.

[52] Alternatively, if the full-generating-production quota is not used up, during the first ten years of operation.
[53] The rules have been changed. Different rules exist for windfarms established after 2001.

6.2.3 Impact of financing conditions on investor cost of production

High RORE and interest rates push the cost of capital beyond the 10% financial discount rate", while short loan maturities require extra-high tariffs during the initial amortization period.

Table 22: Impact of Financing Terms and Conditions on Cost of Production[1)]

Zafarana Windfarm, Year 2004 investment	*piaster/kWh*
Base Case: 70/30% debt/equity, 8 year loans at 13%, ROR on equity=20%	27.7
Case 2: ROR on equity = 15%	24.0
Case 3: 15% RORE + 20 year loans	21.8
Case 4: 15% RORE + 20 year loans + 80%/20% debt/equity	21.0
Case 5: 15% RORE + 20 year loans + 80%/20% debt/equity + 8% rate of interest	17.1
Case 6: Conditions as in case 5, but 1-Year Mixed Credit reduces principal 30%	12.1

1) Without abolition of import duty and sales tax

Table 21 and figure 12 illustrate the impact of successively improved financing terms (rate of interest and RORE) and conditions (maturity and equity cofinancing share) on the PPA-tariff. Whereas the *financial cost of production* for a year 2004 windfarm at the Zafarana site is 16.2 piaster per kWh; the *investor's cost of production* under domestic capital market terms in Egypt is 28 piaster per kWh.

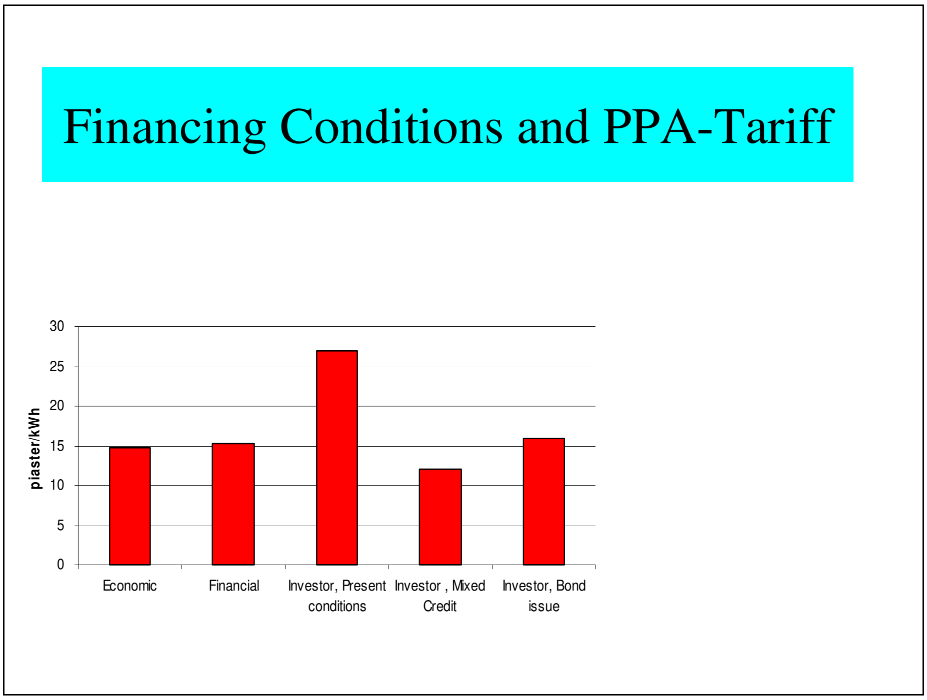

Figure 12: Financing Conditions and Level of PPA-Tariff

If the financing terms of case 6 in table 21 are combined with the abolition of the import duty and the sales tax, the investor cost of production gets down to 10.6 piaster/kWh, which is close to the avoided economic cost.

6.2.4 Absence of hedging instruments for foreign exchange risk

As long as the tariff revenue is fixed in local currency without indexation to the foreign exchange rate, a windfarm investor taking a loan in foreign currency is exposed to the foreign-exchange risk. It is not possible in Egypt to sign a hedging contract against foreign exchange risks.

That is a serious handicap. It is risky in an "emerging market country" with no hedging options to implement a windfarm program, which on the expenditure side is financed by loans fixed in foreign currency and on the revenue side is paid a tariff fixed in local currency, which is not indexed to movements in the foreign exchange rate.

The foreign exchange risk has three implications for the project cost of capital. Due to the higher risk of default on loans taken and repaid in foreign currency:

(i) lenders will insist on a higher equity portion;
(ii) lenders will add a risk premium to the rate of interest;
(iii) the investor will add a risk premium to his benchmark rate-of-return on equity.

Even in the case of soft-loan financing, these premiums increase the required break-even tariff beyond the "avoided cost level" of 10 piaster per kWh. The cost of tariff impact of the foreign exchange risk is, thus, a make-or-break issue for the proposed windfarm program: unless a solution for mitigating the risk is found, private windfarm investments will not come forward.

6.2.5 Year 2002 Regulations on financing of Foreign Direct Investments

New regulations for foreign direct investments adopted by Parliament state:

> ”for projects *which don't generate foreign currency income*, the *tendering* shall be with the following conditions:-
>
> - The required financing and its related annual cost shall be in local currency.
> - The project financing can be in a foreign currency, on condition that the yearly payments shall be from the export revenues achieved by the project (goods or services).
> - With respect to the project that has foreign currency income, the foreign component[54] shall not exceed 50% subject that the foreign currency revenues from operation shall be sufficient to serve the yearly foreign currency obligation, in case this revenues are not sufficient to cover the above mentioned requirements. The developer shall be responsible to export Egyptian goods equal to the deficit of his obligation."

The year 2002 regulations were strongly influenced by the experience with the foreign exchange impact of the first three BOOT-projects in the power sector: EEHC's annual payments on the three PPAs - expressed in US$ and guaranteed by the Government - amount to US$250 million per year

[54] Does "foreign component" refer to "foreign equity ownership share" or to "import content of the investment" or to "import content of the final marketed product"?

once all three projects are in operation. The unexpected[55] devaluation between 2000 and 2002[56] , therefore, made the BOOT-deals look less attractive than expected when they were signed. The cost of capital of the foreign finance, or more precisely - the risk premium of the foreign exchange risk - turned out to be higher than perceived, when the bids were opened and the winner was picked. EEHC makes losses on its PPAs until EEHC is allowed to adjust its own consumer tariffs upwards.

The new regulations place *restrictions on foreign capital movements in general* – foreign equity and foreign loans - the thinking being that foreign loans and equity should not be invested in private projects that do not generate foreign exchange. Or, more precisely, a foreign investor can provide a foreign loan as long as the amortization payments are fixed in EGP at the exchange rate prevailing when the loan is signed.

The foreign exchange impact of windfarms is in section 4.1 shown to be neutral to positive. In principle, it should be possible for a private investor to get authorization to let up to 50% of repayments be fixed in foreign currency. It practice, as the foreign exchange impact is indirect, it would probably be politically impossible for a windfarm investor to get the authorization, except for short-term funds, such as the one-year soft loans proposed in later sections of this report.

The regulations seem to *prevent the indexing of PPA-tariffs to foreign exchange rate movements*.

Thus, the foreign investor carries the full foreign exchange risk. Under these conditions, it is not likely that foreign investors will invest in power projects in Egypt, certainly not in investment intensive projects such as wind farms.

Unless the new regulations concern only the financing of projects undertaken by the private sector, the new regulations would prevent NREA from signing soft-loans with KfW, Danida, etc.

6.2.6 Summary conclusion: financial framework to enable price-competitive PPAs

The absence of adequate financing condition undermines the price competitiveness of private investments in windfarms in Egypt. Without a better financing framework, the case for promoting private investments in windfarms is not strong: private project developers are unable to offer the single buyer / distribution company wind-generated electricity at attractive prices. The required PPA-tariffs are far above the financial cost of production and the avoided cost of thermal power.[57]

The creation of a competitive financing framework for private windfarm investments requires that:
- the rate of interest on debt is brought down from 13% to 10%;
- the maturity of debt for project financed is expanded from 8 years to 15-20 years;
- the RORE-expectations is brought down to 15%;
- project finance is in local currency, as no possibility exists to hedge foreign exchange risks.

[55] The Egyptian economy was hit by four recent shocks: (i) the South East Asian crisis of 1997 and the slow recovery of the world economy; (ii) the drop in international oil prices facing Egypt's oil exports; (iii) the temporary decline of tourism during 1997/98; and (iv) the 9-11, 2001 events.
[56] Depreciation between May 2000 and Mid-2002 is some 33 percent.
[57] For similar capital-market reasons, Morocco's tenders for private windfarms resulted in expensive PPAs.

Section 6.3 lists a number of financial innovations, which, if introduced on the *national capital market* can bring about this change.

The weakness of the capital market in Egypt is caused by a vicious circle of "no supply of bonds and equity because there is no demand, and no demand for bonds and equity because there is no supply".[58] The new financing proposals, on the one hand lack realism, dependent as they are on overall reforms of the capital market. The other side of the coin is that a successful introduction of the new financing instruments, if successful, will have *a cross-cutting importance for the economy, which goes far beyond the windfarm sector*.

Section 6.4 recommends changes in the *terms and conditions of the soft loans* offered by KfW, Danida, Spanish and Japanese aid so they support the creation of a commercial financing structure for private windfarms. If investments in windfarms during the "non-commercial period" are to prepare the future, they must enable the establishment of a national financing framework.

The principal recommendation to donors is to offer soft credits (with a 35% grant element) as 1-year loans. This lending modality changes the strategic use of the soft loans. Under the present lending terms, the soft loans fulfil two functions: (i) to channel foreign grants to investments in windfarms, (ii) to provide long-term project finance. In the new structure, the soft loans (i) channel foreign grants to the investment, and (ii) provide short term finance to fund the construction of the windfarm until commissioning; the long-term funding is secured on the national capital market.

6.3 New Financing Instruments on the National Capital Market

6.3.1 How to reduce rate of return expectations

The 20-25% RORE expectation of the "private investor-class" in Egypt for investing in a project is a rational position for investors in an emerging market economy. But, it is not compatible with the reality of windfarm economics if applied to a 30% equity co-financing share.

There are two main ways to reduce rate of return expectations. One is to reduce risks, the other to increase competition in supply. The proposed financing reform attempts to do both:

- The *new financing instruments lower the barriers to entry in large scale investment projects* by reducing the equity share which the project developer must come up with. This may make it possible *to attract a new class of entrepreneurs that accept a 15% after-tax-rate-of-return-on-equity for low-risk projects* ("increase in supply effect"*)*.
- Another, more realistic, expectation is that the required rate of return on equity and on long-term debt (bonds) is reduced as financial closure for long-term finance is postponed until commissioning ("construction risk eliminated"). The *passive equity investors, providing supplementary equity* up to the bank-dictated level, might *accept a 15% rate of return*, while the active investor gets a 20-25% RORE on his equity investment in project development.

[58] The strength of the capital market in the US and the UK was founded in the late 19th century in the heavy demand for capital for large-scale private investments in infrastructure: canals, railways, ports, electricity. In the developing countries these are typically done by state-owned companies taking their finance either from state-owned national development banks or not at all on the national capital market but from bilateral or multilateral development banks.

6.3.2 New financing agents for investments in windfarms

The financing framework for private investment in windfarms involves four agents, as shown in figure 13.

The *active investor's* - the *project developer's* - main financial contribution is the time and money spent on project development. A larger equity portion up to the full co-financing share required by the debt-financing bank is a possibility, and, in fact, the rule when the project developer is a power utility, which invests in a windfarm as a portfolio-investment.

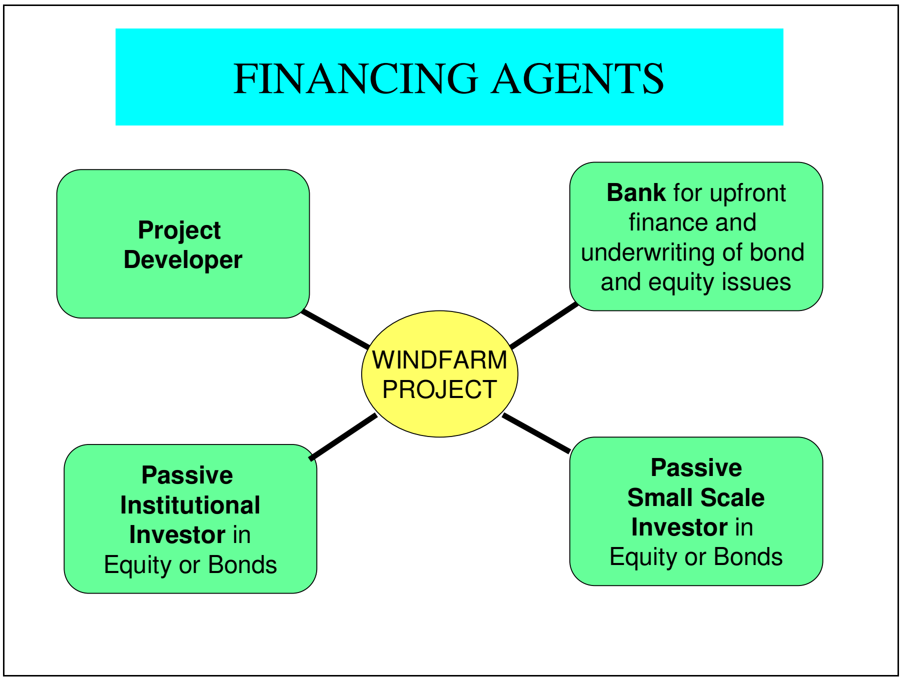

Figure 13: Financing Agents

The developer needs to ally him/herself with a *private bank* having an active interest in taking on the specialised activity of windfarm finance. To bid, the project developer must have pre-arranged finance facilities for the project. The key to win a tender for a windfarm PPA – the key success factor for project development - is to get the least-cost financing package for the project. The bank has two crucial functions in this:

- One is to co-finance the project up to the time of commissioning. During the "non-commercial" period it will for this receive the soft credit which it on-lends to the developer.
- The other is to structure the financing package, which at decommissioning repays the soft loan. The bank would help in issuing, and possibly underwrite,[59] the bond or equity issue

59 Underwrite: An arrangement under which a financial house agrees to buy a certain agreed amount of securities of a new issue on a given date and at a given price, thereby assuring the issuer the full proceeds of the financing.

for the project, or put together a syndicate of banks to provide long-term loans to the project.[60]

The bond or equity issue is sold to the *passive investors*, either institutional investors and/or small household-investors.

Pension funds and insurance companies are potentially interested *institutional investors*. The characteristics of windfarms - long lifetime, secure revenue flows and relatively low operating costs - match the investment profile of pension funds and insurance companies. Due to the relatively low commercial risk of windfarms, a 15% RORE on issued equity and a 10-12% rate of return on bonds may be an attractive investment option.

Another target group for the marketing of windfarm equity and revenue bonds are the *small-scale passive equity investors*, middle-class households looking for safe, long-term assets to invest in. At present, term accounts in banks are the best alternative financial placement option for households. The interest rate for bank deposit is up to 9%, which in view of the 2.5% long-term inflation rate is remarkably high by international standards.

6.3.3 Institutional Investor-Windfarm Project Developer collaboration

One potential financing option, which MEE/NREA can seek to get established in Egypt, is the *"Institutional Investor-Windfarm Developer Collaboration"* model. The windfarm developer would from the beginning of his project development activity seek a collaboration agreement with an institutional investor, such as a pension fund or an insurance company. The institutional investor gets exclusive financing rights for the project, and thus, majority ownership of project equity.

The collaboration could be established on (i) an ad-hoc project-to-project basis, (ii) on a multiple-project basis, where the institutional investor offers to provide finance at a pre-defined rate to all windfarm project that meet a set of well-defined financial criteria, .or (iii) be formalised through the establishment of a jointly owned Joint Stock Company for investments in windfarms.

[60] The technical terms for this is "Syndicated Loan": A commercial banking transaction in which two or more banks participate in making a loan to a borrower.

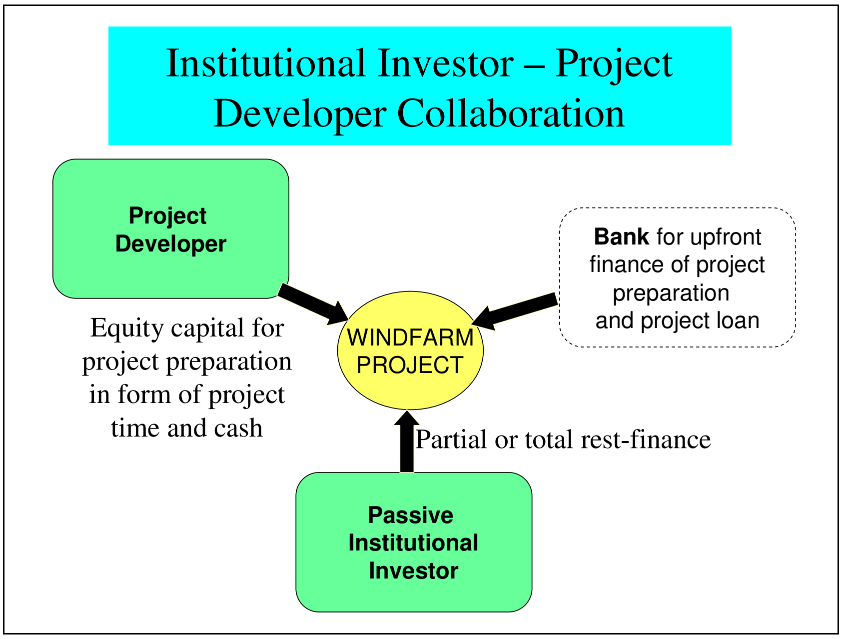

Figure 14: Institutional Investor Financing Model

In the division of labour, the developer provides the technical know-how in project development and windfarm operation, the institutional investor provides financing know-how as well as the majority of equity finance.

Depending on the ad-hoc-agreement, the project developer may hand over 100% ownership of the project to the institutional investor after commissioning, or keep a minority equity share also during operation.

The institutional investor may be interested in providing all rest-finance (the portion to project finance not provided by the project developer) or just the rest-equity portion, leaving the loan finance to be provided by a bank. Since the institutional investor can get the bank loan through balance-sheet-finance, the interest rate would be lightly lower than in the case of pure project finance.

6.3.4 The Multiple Small Equity Investors' Option

Another financing innovation, which MEE/NREA can seek to promote is the "Multiple Small Equity Investors" model for project finance. In this, a project developer with financial assistance from a bank develops a project to bid in the tender (for the PPA with the system operator or for the lease of the land of a wind-site). Having won the bid and having signed the EPC-contract with the wind-turbine supplier, a prospect for the project is published and a marketing campaign is initiated aimed at small individual investors. The capital cost of the project is divided into a large number of small individual shares or ownership certificates, and the price per share is fixed to cover the total required amount of project finance. The advertising campaign indicates, referring to the information in the prospect, the expected after-tax-dividend or rate of return on the shares; and that the windfarm developer will get a management contract for the operation and maintenance of the plant.

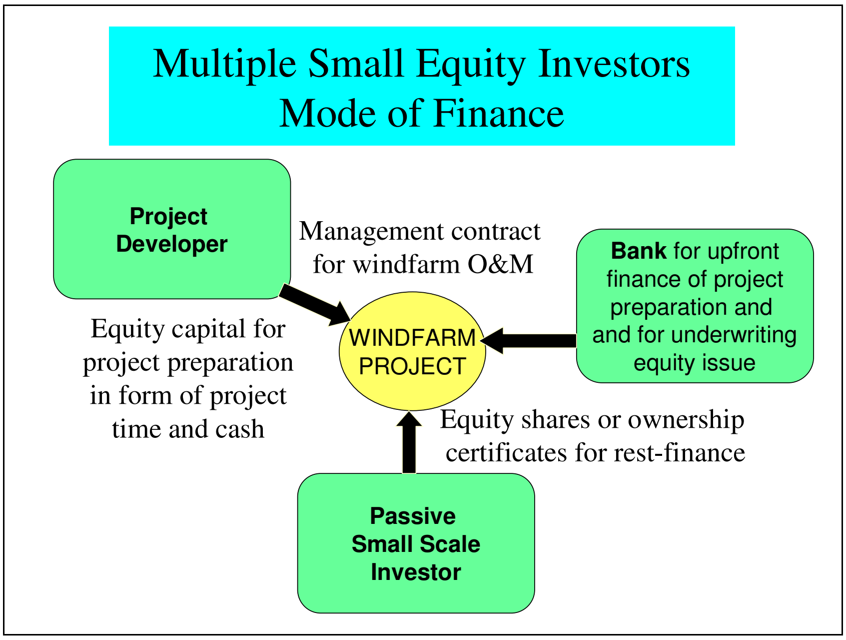

Figure 15: Mulitple Small Equity Investors Financing Model

The project, like the normal institutional investor model, is 100% equity financed. The reason why the cost of capital is competitive despite the 100% equity share, is that small family-household investors have smaller RoE expectations than professional project investors in Egypt. For households a RORE of 10-12% may look attractive compared with alternative low-risk placements such as term bank accounts. Alternative equity investments in public companies[61] would normally yield a higher RORE, but carry a higher risk.

6.3.5 The Bond-Issue Option

The *"revenue-bond"* is a third financing option:

- The windfarm developer, supported by a bank, finances initial project preparation through a mixture of bank loans and personal equity. Project development costs are 5-8% of the cost of construction, meaning that little equity is needed. Interest during construction would add an additional 4% to the EPC-contract. (Supplier credits would be used in the future commercial period, during the non-commercial period soft loans fund the EPC-contract.)

- While construction takes place, the bank prepares a revenue bond issue for the investor, based on the future net revenue that is generated by the windfarm, and secured by the physical assets of the wind project and a financial buffer. The bonds are sold upon commissioning of the windfarm, replacing all finance except the small equity portion of the windfarm developer.

- The windfarm developer operates the windfarm as owner.

[61] Definition of "public company" = companies quoted on the stock exchange.

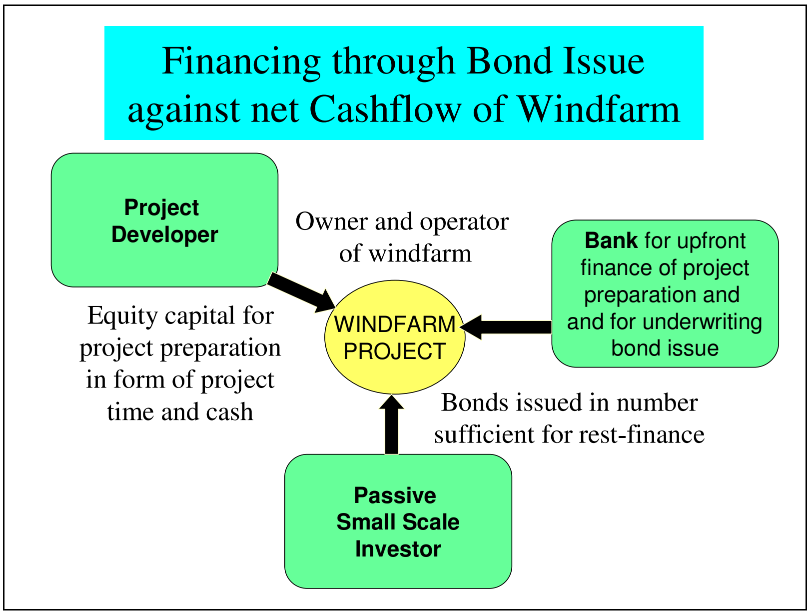

Figure 16: The Revenue Bond Financing Option

The revenue bonds are secured by various accounts established upon bond issuance. Some of these are risks prior to commercial operation (if the bond issue takes place before construction), others safeguard the ability to pay the fixed annual dividend amounts also in years with below average wind conditions. The total amount of project finance to be raised by the bond issue, is, therefore, larger than in the institutional investor model.

If market demand requires it, a series of bonds can be issued, with maturities from as early as 2 years to as late as 20 years.

A real life example of a bond issue for the financing of a windfarm are the revenue bonds issued by Energy Northwest, a publicly owned utility in Washington, for a 48 MW wind project in 2001.[62]

Table 23: Energy Northwest Bond Issue for 49 MW Windfarm. Use of Funds

	US$	In % of total
Bond Proceeds Account	53,657,708	76%
Debt Service Account	6,151,933	9%
Reserve Account	5,960,200	8%
Reserve and Contingency Account	800,000	1%
Operating Reserve Account	200,000	0.3%
Indemnity Contract Fees	2,872,356	4%
Cost of Issuance	1,041,426	1%
TOTAL	70,683,623	100%

[62] Ryan Wiser, Berkeley Lab. Subject: Energy Northwest Bond Issuance for 48 MW Wind Project. Memo. December 2001

The *Bond Proceeds Account* covers project constructions costs. The *Debt Service Account* is created to help pay off interest and principal on the bonds. The *Reserve Account* is created to provide further security to bondholders. The *Reserve and Contingency Account* is established for major capital improvements, repairs, and replacements. The *Operating Reserve Account* will initially be used to cover any O&M costs, and later used to level out costs from year to year.

The revenue from the sale of the bonds thus covers three categories of expenditure:

1. Development and construction of the wind project and related T&D and interconnection investments. (76%)

2. The build up of initial financial buffers, which represent genuine financial assets belonging to the bond holders. (19%)

3. Two "sunk cost" items of no future value for investors - the indemnity contract fee and the cost of issuance. (5%)

6.3.6 The bullet-loan option

A bullet loan is a term loan with periodic instalments of interest, while the entire – or majority – of principal is due at the end of the term as a final payment. The final payment on a balloon loan is sometimes referred to as a bullet.

When national bank regulations – or market conditions – force banks to offer medium term loans only, the bullet loan-option can be used by banks to construct a series of consecutive medium loans that have the yearly amortization profile of a long-term loan. A seven year loan, for example, can have an annual interest and repayment profile of a 15 year-loan, with the rest-principal due at the end of the 7^{th} year. At that time, the bank issues a new seven year loan for the "bullet-payment", repeating the annual payment profile of the previous loan. The procedure is repeated until the loan is repaid.

The procedure, however, poses a liquidity risk for the bank, as it presupposes that the bank at the end of the seventh year period is not in a liquidity crunch, forcing it to insist on the bullet-payment. This risk can be mitigated by liquidity stand-by guarantees by a third party; but this entails new costs.

6.3.7 Which option is the best and how far is the cost of capital brought down?

It requires financial modeling by specialist Egyptian financial experts to determine the likely cost of capital of the different options. Table 24 provides some rough, indicative estimates.

The *bullet loan* does not reduce the cost of capital, but reduces the requires PPA-tariff due to its reduction of the annual amortization burden during the initial years.

The *institutional investor* case in its most simple version is a means to reduce RORE, leaving the cost of debt unaffected. The other options also have the increased maturity effect, but in addition also the reduced cost of capital effect.

The calculation of the rate of interest on the *revenue bond* is based on the following assumptions. Households can get up to 9% rate of interest on their bank deposits. It will require an interest rate spread of at least 2% to get these to shift into bonds since these have a lower liquidity. The cost of issuing the bonds and of annual administration adds at least 1%, giving an interest rate of 12%.

The *multiple equity* option, in principle, has no higher risks than the revenue bond option. But it has the inconvenience of fluctuating annual payments and, presumably, of lower liquidity. This is why a RORE of 13% is assumed for the 95% portion of the equity that is purchased by households.

Zafarana Windfarm, Year 2004 investment. No import duty, no sales tax	***Cost of Capital***	***Piaster/kWh***
Base Case: 70/30% debt/equity, 8 year loans at 13%, ROR on equity=20%	15.1%	24.2
Bullet loan at 13%, 70/30% debt/equity, ROR on equity=20%	15.1%	21.4
Institutional Investor: 70% loan at 13%, 5% equity at 25% and 20% at 15%	14.1%	20.0
Multiple equity option: 5% equity at 25%, 95% equity at 13%	13.6%	19.0
Revenue Bond: 5% equity at 25%, 95% bonds at 12%	12.7%	18.5

Table 24: Cost of Capital and Cost of Production. Year 2004 Zafarana Windfarm

At a more general level, one can list the following comparative advantages of the individual options:

- The advantages of the *Institutional Investor-Windfarm Project Developer* model are (i) the low transaction costs in raising the project finance and (ii) that the reserve and contingency accounts can be kept at low levels due to the financial strength of the institutional investor, the majority owner.

- The total "buffer funds" in the *"multiple equity investor"* case are slightly lower than in the "*revenue bond* case". The fixed annual payments on bonds call for additional reserves to guarantee payments also in years when the wind regime is below average causing a drop in revenues.

- For the project developer, the "revenue bond" and the "multiple equity investor" models have the advantage of offering higher returns and higher fees than the institutional investor model.

- Which option would *household investors* prefer? The multiple equity investor model gives direct ownership control through the Annual Assembly of Shareholders, the "revenue bond model" gives a fixed annual revenue throughout the 15-20-years lifetime of the bond.

6.4 Financing Innovations on the Donor Side

6.4.1 Introducing 1-year soft loans

Presently, donor soft loans are given as long-term loans. The national capital market is bypassed in the funding of windfarm investments with the result that no capacity and institution building takes place on the financing side. The national banks channelling the soft loans to investors (NREA) are simple administrators for the process of making disbursements and collecting annual amortization payments. Neither they, nor any other national financial institution have an active role to play in project finance.

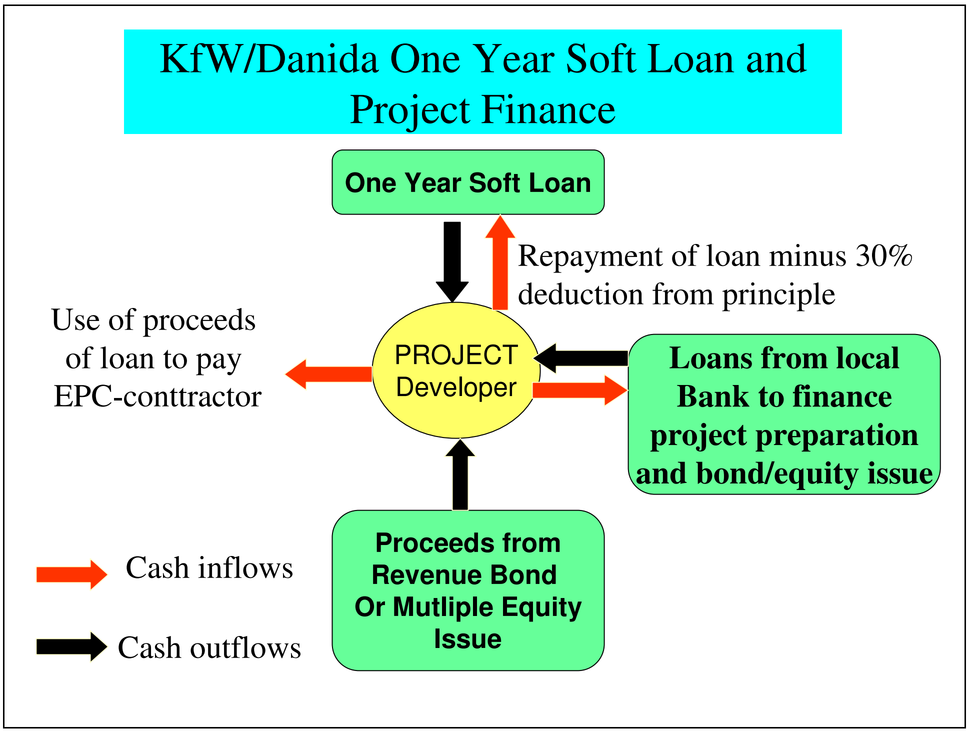

Figure 17: Scheme for making Use of One Year Soft Loans

The 35% grant element of the soft loans is essential to reduce the economic cost-benefit gap and make windfarm investments economically as well as commercially viable in Egypt. But unless the modality for the funding of windfarms is changed to actively incorporate the national capital market in providing long-term finance on commercial terms, the projects do little in terms of preparing the future. Neither on the developer side – where NREA, being financially insolvent, is not a credible commercial operator[63]. Nor on the funding side, where Bank of Egypt onlends soft loans to NREA, although the PPAs are written in a language, which does not guarantee sufficient revenue for debt-service-cover.[64]

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[63] NREA's situation is not caused by lack of internal technical capacity. NREA has not been given the financial means to become a financially sound institution.

[64] Due to the year 2003 devaluation and its impact on the amortization of debt in foreign currency, the present tariff of 10 piastre/kWh is insufficient to provide full debt-service. The PPA allows for adjustments in the tariff after mutual

According to the so-called Helsinki agreement for the approval of OECD's Committee for soft loans (mixed credits), soft loans for low-middle income countries have a grant element of 35%.[65] The grant element is the difference in the NPV of the amortization streams of a commercial export credit and a soft loan for the project. Borrowers can chose between a credit with a long maturity (e.g. 10-20 years) but a positive interest rate, or a loan with a shorter maturity (e.g. seven years) with a zero or negative interest rate: if a zero interest rate on a loan with a short maturity does not result in a 35% grant, a deduction is made in the principal of the loan; meaning that not all of the loan is repaid.

Recalling that the objective of donors is to assist the development of a large-scale market for windenergy in Egypt, the recommendation to donors is to provide their soft credits in the form of one-year loans; to reach the 35% grant, only about 70% of the principal would be repaid.

Except for the grant element, such a soft loan has the characteristics of a traditional short-term supplier's credit, allowing project developers to finance the cost of investment until commissioning, at which time the financial closure for the domestic long-term finance must be in place. At commissioning all costs of project preparation and construction are known, and the windfarm is operating. This reduces the risk for domestic financiers and facilitates financial closure.

6.4.2 Common tenders for donor-financed windturbines

So far, Danida Mixed Credits, KfW, Spanish aid and Japanese aid have signed separate agreements with NREA for providing soft loans to specific NREA windfarm projects. NREA then, except in the case of KfW, organises a tender for Danish windturbine suppliers for the Danidas Mixed Credit, for Spanish suppliers for the Spanish aid loans and for Japanese suppliers for Japanese aid loans.

In order to bring the procedure in line with the private sector – free market philosophy – of a mass-market windfarm program, NREA and donors ought to agree on either:

- *open individual tenders*: the four donors agree to organise open tenders, allowing turbine suppliers from the four countries to bid on a non-discriminatory basis; or on
- *joint tenders with open-ended annual budgets*: private investors can in accordance with pre-defined rules organise open tenders for the supply of windturbines; if a Spanish windturbine supplier wins, Spanish aid provides the soft loan, if it is a German supplier, KfW provides the soft loan, etc.

The joint tender procedure complicates life for donors: the Ministry of Finance in the donor country wants to know how much money is being committed, when it authorises a given loan amount to be allocated to Egypt.

The individual tender procedure complicates life for investors and for donors. Project developers want to get the cheapest offer from turbine suppliers in order to win the tender they participate in

agreement between NREA and EEHC and subject to approval by the regulator. But it does not define criteria for what justifies an adjustment in tariff.

[65] For the lowest income countries, the grant element is 50%.

for getting a specific windfarm site. How do they know which donor-soft loan to select for their tender and how do donors select among developers?

6.4.3 Can donors provide one-year loans?

For donors, the proposed one-year soft loan would be a new financial product in their portfolio – maturities of present Danida, KfW, Spanish and Japanese soft loans range from 7 years to 30 years.

Is the introduction of the one-year loan politically and practically feasible? Three hurdles would have to be overcome.

One is a *change in thinking or self-perception of the organisations providing the soft-loans*. Their function has been to give long-term loans at concessional rates to capital-intensive projects in countries, where it is difficult or impossible to raise long-term loans on the national capital market. The idea of giving one-year loans as part of a longer-term strategy to strengthen the capital market in the recipient country, means moving into a TA-area, which more naturally belongs to the realm of their colleagues in the bilateral development aid departments.

The introduction of the one-year loan requires a *change in the formal mandate of the organisation* – not necessarily of the statutes (that would be impossible) but a formal approval by the Board to engage in such kinds of activities.[66]

The third is *acceptance by the OECD Committee on soft credits* of the concept of the 1-year soft loan. Since it looks so much different from a normal soft loan, the first presentation of a windfarm project being financed in that way may cause some eyebrows to be raised. But, resistance, if any should be short-lived. First, the role of the Committee is to safeguard against competitive distortions, and no artificial distortion of trade is involved. Second, as a rule, the Committee supports the strengthening of the development impact of soft credits.

6.5 Developing Windfarm Projects as CDM-Projects

6.5.1 Securing fulfilment of the additionality criterion

Egypt will, within the near future, ratify the Kyoto Protocol and, in accordance with the Marrakech accords set-up a Designated National Authority (DNA) for the national approval of CDM-projects. Once the DNA is in place, new windfarm projects in Egypt can be submitted as CDM-projects to the DNA with request for approval.

To be approved as a CDM-project by the CDM-Board, the project must fulfil the additionality criterion: that the project cannot be implemented without the CER-revenue.[67] This criterion is

[66] The statutes of Danida's Mixed Credits do not seem to prevent the launch of the 1-year loan.
[67] The first 14 projects were rejected in June 2003 by the CDM-Board. Six of these with the message that they will be approved after some re-writing of the application, the other eight were met with more fundamental objections.

certain to be fulfilled if ERA, as a matter of pricing principle, fixes the PPA-tariff at the avoided cost of thermal power production. Because then even with soft loan-finance, windfarms will not for many years be commercially viable without CER-revenue.

CDM project developers can chose between: (i) a crediting period for a maximum of seven years, which may be renewed at most two times or (ii) a maximum crediting period of ten years with no option for renewal. For wind farm projects the obvious choice of crediting period is three times seven years. Although it is not 100% clear at project start how many emissions per kWh can be claimed during the second and third periods, as the baseline is reconsidered after each seven years, the long term power expansion plan of EEHC provides good guidance.

According to the calculations presented in section 2.2.3, at an assumed price of US$4/ton CO_2, the year 2004 emissions of 0.50 kg CO_2/kWh give a *CO_2-revenue of 1.1 piaster/kWh*. The payment falls each year, due to improved thermal power plant efficiency. In 2024, the average emission in steam turbine plants of 0.43 kg/CO_2 triggers a payment of 1.0 Piaster/kWh.

6.5.2 Are projects financed by soft-loans eligible as CDM-projects?

The Kyoto Protocol states that *public funding of a project should not result in a diversion of ODA (Official Development Assistance) from Annex-1 parties*. Any funding for the CDM is to be additional to- and not substituting for funds flowing from Annex 1 countries. This suggests that Certified Emission Reductions cannot be earned in a case of such a diversion of ODA. A letter from the government stating that the funds are not being diverted form other sources must certify that this is the case and the *CDM-Board* as final approval authority must accept that the additionality criterion is fulfilled.

A crucial question for donors, therefore, is whether it is possible to *give soft loans to CDM-projects and still get the grant element approved as ODA by DAC* (Development Assistance Committee) at the OCED in Paris. Some experts have interpreted the non-diversion clause to mean that ODA funds cannot be used to co-finance the cost of investment in a CDM project. ODA-funds may, however, be used for CDM capacity building, technology transfer or other activities not directly related to project implementation. This is too hard an interpretation, and short of logic.

- Donors have for many years used ODA-funds to support renewable energy projects in developing countries. Egypt has for several years received mixed credits from Denmark and Germany for windenergy projects. Being the continuation of a long tradition of soft-credit funding, the financing of CDM-windfarm projects in Egypt by Spanish, Japanese, German and Danish sot loans does not represent a diversion of ODA-money.
- Allowing traditionally ODA-financed projects to be eligible as CDM-projects reduces the amount of ODA-funding, needed to make the projects commercially viable. ODA-funds are saved that can be used for other purposes. Disallowing a “classical ODA-financed” type of projects to be accepted as CDM-project, instead, imposes a diversion of ODA-funds, as additional ODA-money must be channelled to the project to cover the revenue shortfall!

As long as there is a clear separation between the co-funding of a windfarm project by a soft loan (giving no entitlement to the project-CERs), and the purchase of the CERs by another party under separate contract with the developer, the non-diversion criterion should be complied with.

6.6 Summary Table of Financial Incentives to Windfarms

Under these assumptions, the financial support to windfarms in Egypt is composed by a mixture of "donor pays", "tax payer pays" and "electricity consumer pays" subsidy instruments as shown in table 25.

Subsidy Instruments for Egypt Windfarms

	Cost of Investment	Cost of Output
Donor pays + CDM	• Investment grant • Subsidized investment loan (mixed credit)	• GEF top-up premium during first five years • CO2-certificate sale
Tax payer pays financing	• LNG-Savings Fund pays investment grant • Import duty exemption • Low interest rate loan	• LNG-savings fund pays topping-up kWh premium
Electricity consumer pays financing	• EEHC invests in coastal transmission line to Hurghada (connecting MW line + cost of connecting paid by windfarm) • National postage stamp transmission tariff	• PPA with windfarm > avoided financial cost for system operator (premium = difference between economic value of gas and price paid by power plants)

Table 25: Subsidy Instruments for Windfarms

It is assumed that for reasons of "clear price signal setting" and for "administrative ease", the electricity regulator will approve windfarm PPAs that are based on the economic price of gas at the power plants (the netback value of exported LNG). How much of this "burden" will end up being paid by the electricity consumers depends on the level of compensation, which is paid to the system operator / single buyer by the LNG-Fund.

7 MARKET SCHEME FOR PRIVATE INVESTMENTS IN WIND FARMS

7.1 Price based or Quantity based Approach?

7.1.1 Three basic categories of approaches to market development

"Electricity consumer pays" support schemes for grid-connected renewable energy systems fall into three main categories, of which one is *price-based*[68] and two *quantity-based* in their approach:

1. Feed-in tariffs, used in Denmark, Germany, Spain, and France since 2001.
2. Bidding for long-term PPAs with the system operator / national transmission company, such as Ireland's "Alternative Energy Requirement" Scheme.
3. Tradable green certificates schemes, used in U.K., Italy, Netherlands, Denmark, Belgium, Austria, Sweden, where electricity suppliers[69] are obliged to supply a certain quota of renewable energy.

Each category has a number of sub-categories:

- Among *feed-in-tariffs* one can distinguish between "fixed price/uniform tariff", "declining scale tariff" and the Spanish "hybrid feed-in-tariff / kWh-subsidy" schemes.[70]
- *Tender schemes* differ with regard to the mechanism used to fix the PPA price (marginal bid price given to all or each bidder is paid his bid price) and with regard to how the contracted quantity is established: the tender can fix the quantity to contract (bid prices define the financial cost of the tender) or the subsidy amount (bids establish by how many MW(h) can be bought with the price support).
- *Tradable green certificates schemes* can be stand-alone (windfarm revenue = electricity sales + TGC-sales) or coexist with a separate CO_2-certificate market (windfarm revenue = electricity sales + TGC-sales + CO_2-sales).

7.1.2 Comparison of the three approaches under perfect information

In figure 18, Government RE-policy has fixed a RE-supply target of Q1 (MW or GWh) to be reached in period 1 and of QN for period N. When (i) all parties are in possession of *perfect information*, (ii) the *transaction costs* of the schemes are identical, (iii) the perceived *risks* are the same for investors and (iv) there is *no technological progress*, then price-based and quantity-based

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[68] The upfront investment subsidy is another examples of a price-based scheme. But this type of scheme is financed by the public budget, and used for cases of initial market development, not for major market penetration.

[69] Alternatively, or for major self-generators as a supplement, final consumers must consumer a minimum quantity of green tariffs. Voluntary green electricity demand schemes are insignificant.

[70] Under the Spanish renewables pricing mechanism, generators, when signing the PPA, can chose between being paid a fixed windenergy tariff of €0.064/kWh or a kWh-subsidy ("la prima") of €0.029/kWh paid on top of the market price in the power pool.

schemes produce similar results. To reach the quantity Q1, the Government can either introduce a *feed-in tariff of P_1* or fix a *quota of Q1* - the *tradable green certificate (TGC) scheme* leads to a market clearing "green electricity price" (market price of electricity + market price of green certificates) of P_1, which is also the "marginal quota fulfilling price" of a bidding process.

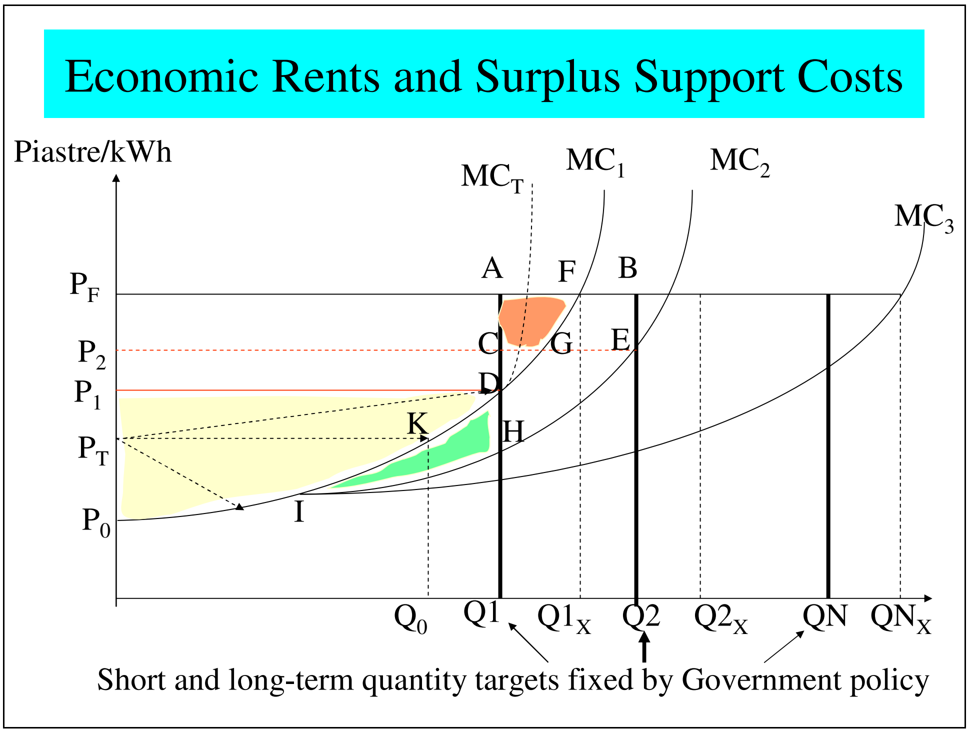

Figure 18: Economic Rents and Subsidy Costs under Price and Quantity based Market Approaches

The producer surplus is P_1P_0D for the feed-in-tariff and TGC-schemes. The producer's surplus of the *tender scheme* depends on the adopted pricing procedure. If all accepted bids making up the quota are paid the *marginal quota fulfilling bid price*, the tender scheme leads to the tariff P_1 and a producers surplus of P_1P_0D just as for the TGC scheme. If, instead, each bidder is paid his *specific bid price*, the result is the average price P_T for the mandated quantity Q_1, on the assumption that tariffs bid by producers reflect their specific position on the supply curve [71]. The tender scheme, in that case, eliminates the producers' surplus.

The subsidy burden imposed by the three schemes, therefore, is identical, except for the "bidded price is paid"-variant of the tender scheme, which has a lower subsidy impact.

The harmonious picture changes when information is less than perfect, and costs of transaction are taken into account.

[71] The extent of the reduction in the producer surplus depends on the extent of bidders' gaming and gambling on the outcome. In case of perfect information, the profit-maximising "below-marginal-cost producers" would all bid a tariff just below the market clearing price and still be certain of getting their contracts.

7.1.3 Impact of insufficient information on market size

When information is less than perfect, policy makers may set the *feed-in tariff* too low to reach the quantitative target – a price of P_T results in the low quantity of Q_0. Or, the price may be set too high: the price of P_F leads to an over-supply of Q1-Q1$_X$, meaning, that a larger than expected financial burden for electricity consumers. The positive, "other side of the coin", aspect of overshooting is the fast development of the market for windenergy, which is why policy makers who want a rapid penetration of renewable energy prefer the feed-in-tariff.

The *tender scheme* has the reputation of providing new RE-supply at low-priced PPAs. However, a main reason for this is smaller market size normally associated with the scheme: the tender scheme is primarily used by countries that are stingy with subsidies and renewable energy ambitions. The low demand from the tenders for RE *allows* windfarm investments to stay on the low-cost end of the supply curve, at least during the initial years; while the tender procedure *forces* projects to stay there: in order to win, projects are done in the windiest areas only. The problem with this is the high geographic concentration of projects on-land, which leads to resistance by the local population in the area against the implementation of new projects. The U.K.'s NFFO-scheme, therefore, resulted in a larger number of "virtual reality" than of real projects: most winning bids did not afterwards pass the local site approval process for the project. The NFFO-scheme resulted in "undershooting".

The risk of undershooting is addressed in the design of the Irish Renewables Obligation scheme. It is an eligibility condition for participating bids in tenders to have the planning permission for the project in place.

7.1.4 Insufficient information and the level of the subsidy burden

Due to the inability of planners to set the *feed-in-tariff* at the "correct" price of P_1 for reaching the targeted quantity of Q1, the adopted tariff P_F leads in period 1 to a producer's surplus of P_0P_FAD (for quantity Q1) + AFCG (for the "overshoot quantity" Q1Q1$_X$). Compared with the TGC-option, the feed-in-tariff increases the subsidy cost of RE by the amount of P_IP_FAD for quantity Q1 plus an "over-payment" of ACFG for the overshoot quantity Q1Q1$_X$ - a TGC-scheme would in period 2 have provided the quantity Q1Q1$_X$ at the lower price of P_2.

Overshooting (impact on market size) is one reason why feed-in-tariffs gained the reputation for being expensive; the other, associated reason, is the financial burden of the *high "producer' surplus / incremental rent"* which producers reap under the uniform (fixed price) feed-in-tariff scheme.

7.1.5 Impact of transaction costs and risks on MCCs and type of investor

The feed-in-tariff is ideal for investors: there is *no market risk*, the project can *be implemented any time during the year* as soon as financial closure has been secured, and the *formal procedure for signing the PPA* with the system operator / local utility is simple. The feed-in-tariff scheme, therefore, is capable of attracting a broader scope (small and large, professional project developers and ad-hoc project developers, utilities and IPPs) than the tender scheme.[72] This "agent" impact is another reason for the *faster expansion of the market* that takes place under a feed-in-tariff: due to the larger number of investors, more projects get implemented.

The tender scheme is at the opposite end: it attracts major players only. Thus, if you want to get small projects developed as well – the situation in Germany and Denmark where small stand-alone or mini-windfarms are scattered across the landscapes – the tender scheme is not the way to go.

For a given tariff level (feed-in-tariff = PPA of tender = price for TGC-output), the potential size of the market developed by a feed-in-tariff scheme is larger than for the other two schemes. The assumption, usually seen in graphic analysis, that the three schemes have identical supply curves is wrong: each scheme has its own unique MC-curve.73 The higher market risks of the TGC-scheme increase the cost of project finance, and thereby, the RE-cost of production; whereas higher transaction costs push up the cost of production of the tender scheme. In figure 18, MC1 is the MC-curve of the feed-in-tariff scheme, while MCT represents the MC-curve for the tender scheme. The position of the two is more or less identical at the low-cost end, which are large sites located at windy locations. But the MCT-curve is steeper due to increase in transaction costs per kWh when small marginal sites are developed. Due to the higher cost of production, the least attractive sites, which are still doable under a feed-in-tariff scheme, are not commercially viable under a tender scheme. The quantity, which a tender PPA-scheme can develop, if the maximum tariff is fixed at PF, is below Q1X.

Table 26: Impact of Market Scheme on Costs of Transaction and on Risks for Investor

Type of Scheme	Transaction Costs	Investor Risk	MC-Curve
Feed-in-tariff	*Low*:	*Low*: no market risk	*Low-cost*
Tradable Green-Certificate	*Medium*: fees for TGC-dealers and brokers; costs for negotiated long-term PPA-prices or for day-to-day power pool sales	*Medium*: risk of fluctuating market prices for electricity and for TGCs	*Small inward-shift in position*
Tender	*Medium/High* for Government (organisation and implementation of tender) and for investor (preparation of bidding documents and time in waiting for tender to take place)	*Medium/High*: risk that project implementation is delayed several years until tender prices have gone up	*Small initial inward-shift turning steep for marginal sites*

7.1.6 Impact of technological progress on market size and producer rent

Technological progress, shown by the outward shift of the marginal cost curve MC_1 to MC_2 and later to MC_3 in figure 18, reinforces the strong market dynamic as well as the "additional subsidy cost" of the uniform (fixed price) feed-in-tariff scheme. The increase in productivity during period 1 from MC_1 to MC_2 affects the three schemes as follows:

- In the *TGC-scheme*, the "green electricity" price for the mandated market Q1 is reduced to P_T and the producer surplus as well as the subsidy burden is reduced by P_1P_TDH.

[72] The TGC scheme, as summarized in table 30 is in between the two on both counts.
[73] The "economic cost of supply curve" is the same, the "investor cost of supply" curves are not.

- In the *tender scheme*, the marginal bid price is reduced from P_1 to P_T, while the average bid price falls below P_T, as all bid prices now fall within the P_0-P_T range.

- In the *uniform feed-in-tariff scheme*, the price paid to the producer is not changed. The decline in the cost of production makes a number of previously unviable windfarm sites commercially viable. This expands the windfarm market and leads to an *"overshooting"* beyond Q2. The *producer surplus* for Q1 is increased by the amount IHD, while the difference between the subsidy cost of the feed-in-tariff scheme and the TGC-scheme is increased by the amount P_1P_TDH.

The above mechanism explains the high price elasticity of demand for turbines witnessed in the markets using the uniform feed-in-tariff: the "explosion" of the German, Danish and Spanish markets for windenergy. Cost reductions made less attractive windfarm sites financially viable expanding the scope (geographic location) and the size of the potential market. A costly, but productive, interaction took place between the demand side (reacting to cost decreases with a high price elasticity) and the supply side (reacting to the economies of scale generated by the increase in demand with further cost reductions). According to the premises of "learning curve theory"[74], the level of the impressive productivity improvements / cost reductions in windenergy technology during the 1980s and 1990s would not have been attained had Spain, Germany and Denmark not applied the fixed feed-in-tariff approach.

A side effect of the higher producer surplus was an "explosion" in the prices for the lease of land for windturbines. A high share of the higher rent did not benefit windfarm developers, but went into the pockets of land-owners and speculators, who were fast in seeing the profit opportunities created by the uniform tariff and purchased early on lease rights at low prices from owners of "windy" lands.

7.1.7 Declining scale feed-in-tariff: impact on producer rent and market size

The need to reduce the producer surplus/subsidy cost of the "uniform" feed-in-tariff led to its replacement by two types of declining scale tariffs:

1. *Tariff rates that decline with the GWh-output per MW* reduce the "wind resource producer surplus" of the best sites, but expand the market by making less attractive sites more viable through the high initial rate. In Denmark, for example, a high rate is paid for the first 25,000 GWh per installed MW, and a lower rate for all GWh during the remaining PPA-period.

2. *Feed-in-tariffs with pre-announced declining scales each year for investments in new windfarms* have two subsidy-reducing impacts: they reduce the "incremental producer rent from technological progress", and keep the annual market expansion below the level, which would be reached under a fixed feed-in-tariff.

[74] Theory which for new technologies shows a close correlation between the doubling of market size and the level of productivity improvements. In the case of windturbines, a doubling of the world market led to a 30% decrease in the cost of production per kWh of new windfarms.

These changes, without affecting the *cost of transaction* and *low market risk* advantages of the feed-in-tariff, reduce the producer rent and subsidy cost of the feed-in-tariff scheme down to the low levels of the tender and TGC-schemes.

Neither the "declining scale feed-in-tariff" nor the "PPA-tender" come out as a clear winner if the objective is to minimize the subsidy burden per installed MW: the feed-in-tariff minimizes the *financial cost of production* of windfarms, the PPA-tender minimizes the *producer's surplus*, and through this, the tariff and subsidy level.

That the TGC-scheme is gaining ground in the EU – as witnessed by the support given to the pilot RECS-scheme[75] and the replacement of the NFFO in the UK by a TGC-scheme – has little to do with any superior allocative efficiency or higher cost effectiveness of the TGC-approach. It has to do with three political factors. One is the political incapability of introducing cost-effective and timely adjustments to the feed-in-tariff in the three pioneer countries, Germany, Denmark and Spain- the vested interests in the existing feed-in-tariff scheme were too strong. The other is the promotion by the EU Commission of the TGC-scheme. The Commission never liked the feed-in-tariff scheme – by reducing the amount of free competitive thermal power supply on the national markets – it limits the potential for cross-border electricity trading, the size of which is a success benchmark for the Commission's internal market policy. The third is the fact that the TGC-scheme fits better into the free-market logic of the liberalized power markets.[76]

7.1.8 Impact of supply side conditions

The graphic analysis assumes that markets are efficient and have the ability to react instantaneously to changes in market conditions: at the end of the period, prices and quantities have settled at the expected equilibrium levels.

Markets, however, need *time to adjust*, and the *effectiveness of different schemes depends on the quality of the supply side:*

- A tender scheme operating under quasi-monopoly conditions will not generate the low prices of a fiercely contested tender.
- When there is an objective short-term scarcity of green power, prices under a TGC-scheme will hit the ceiling established by the "penalty-payment escape clause".[77]

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75 RECS is the "Renewable Energy Certificate System". To ensure that national systems are harmonised, built to the same standards and compatible with each other, RECS members have developed and adopted a set of rules: the Basic Commitment (BC). RECS is administered within each geographical area by an Issuing Body (IB), which is unique to this area and independent of other members of RECS. All IBs are members of the international Association of Issuing Bodies (AIB), which guarantees the compatibility and adherence to the BC of the various national certificate systems. In addition, the commercial operations of each IB are subject to peer review by the AIB

[76] The initial design of the feed-in-tariff in Denmark and in Germany was weak in terms of burden sharing between the distribution companies. A mandated market scheme, on the contrary, imposes the same purchase burden on all retailers, while the TGC allows the amounts to be produced by the least-cost suppliers.

[77] In the U.K., wind output was sold for as little as £0.02/kWh under the former NFFO-tender scheme; under the Renewables Obligation scheme introduced in 2002, a TGC-scheme, prices hit £0.06/kWh.

7.1.9 Type of approach and development of the market over time

Figure 19 illustrates the difference in market dynamics over time of four different market schemes: (i) uniform feed-in tariff, (ii) declining scale feed-in tariff, (iii) mandated market scheme, (implemented as a *TGC-scheme* when there are many competing retailers on the market and as a *tender scheme* when there is a single buyer on the bulk market), (iv) set-aside scheme, where a specific politically determined amount of renewable energy is purchased each year by a tender.

Market development under the *uniform feed-in-tariff* is fast, the major reason being its generous level: it must make good as well as mediocre sites commercially viable. The wind resource potential in the country is, therefore, exploited very quickly as witnessed in Denmark, where the majority of potential on-land sites have been developed. Since 2001, investment in new windfarm capacity on-land is mainly in the form of replacement of old small windturbines by large turbines.

Under the *declining scale feed-in-tariff* the development of the market is more gradual. Yet, it may be less predictable and more fluctuating than the development under a mandated market scheme.

The *mandated market scheme* imposes on electricity retailers the obligation to secure a fixed percentage of their supply from renewable energy systems.[78] The quota grows each year until its politically fixed plateau is reached, making contracts for new investments each year a necessity. Growth in national power demand adds further demand for annual investments in renewables.

Under a *set-aside scheme*, the Government may use a fixed MW(h) quantity for new annual RE-supply, or let the contracted quantity increase steadily each year. The latter case is shown in figure 19.

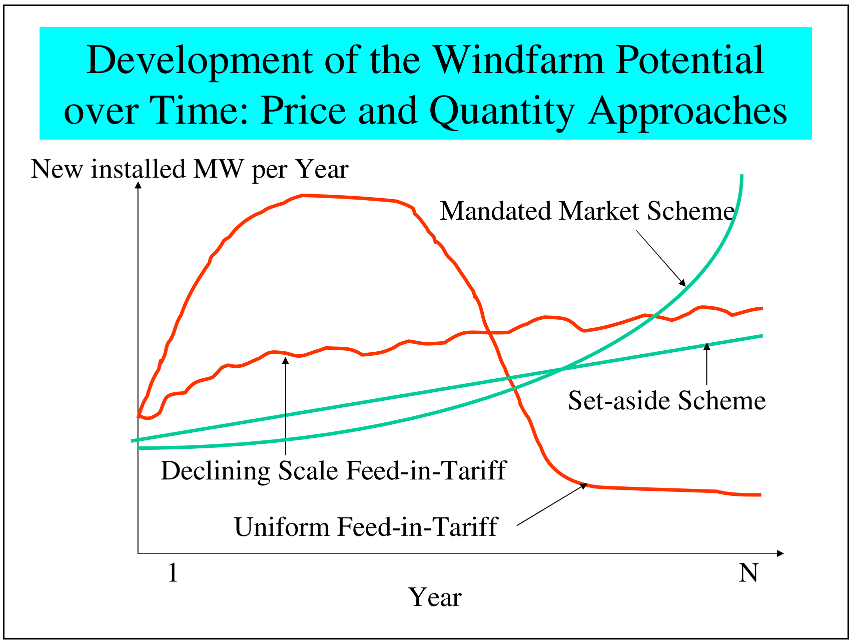

Figure 19: Market Scheme and Profile for Market Development over Time

[78] Operators then have the possibility of generating the required amount of electricity themselves, purchasing it in the long term from a specialised renewable energy generator, or purchasing certificates for specific amounts of green electricity from other operators.

What are the economic consequences of the differences in the profiles shown in figure 19?

There is no doubt that the adoption of the feed-in-tariff adopted in Germany, Spain and Germany was a major determinant for the spectacular improvements in windfarm technology during the 1980s and 1990s; none of the alternative schemes could have accelerated the technology equally fast. There are two reasons for this:

1. Ceteris paribus, a fast growing market attracts more players than a lower growing market. The scheme, in fact, provided an incredibly competitive supply side with many turbine manufacturers fiercely competing for orders.
2. The fast expansion of the *international market* for windenergy drove down the costs of windenergy, confirming the “rule of thumb” from learning curve theory that each doubling of market size for a new technology leads to a 30% reduction in unit costs.

Yet, because the contribution of the *domestic market* of a individual country to the expansion of the international market is small – with the exception of Germany, Spain, USA, Denmark and, now the UK, – an individual country can neglect the “learning-curve-effects” in manufacturing. If it believes its national industry can be internationally competitive, the national market is of less importance except for providing an initially half-protected niche for building up national manufacturing capabilities.

However, there are also drawbacks associated with being an early mover when the technology still has substantial cost reduction potential: *a fast exhaustion of the national wind resource potential for windfarms, leads to a large portion of installed capacity being high-cost. Wind turbines installed today will, not benefit from the cost reductions which technological progress brings to later investments*. Therefore, if the political target is to reach “X” MW of installed capacity by the year “Y”, it pays to wait until the later years with installing a high part of that.

In addition, a rapid market development has a negative impact on the *capacity value of windfarms* - if the speed in the growth of installed windfarm capacity is faster than expected!. Windfarm capacity has a thermal power capacity replacement value only if the availability of windfarm capacity is taken into account in thermal power expansion planning. Otherwise, the impact is over-capacity in installed generation. In Denmark, for example, investments in new windfarm capacity during the 1990s had a capacity value close to zero; or, seen from a different angle: the new thermal capacity installed during the 1990s had a capacity value of zero.

7.2 Choice of Market Scheme in Egypt

7.2.1 The context in Egypt: factors determining the design of the scheme

The analysis of the three schemes in section 6.1 is context-neutral. The and pros-and cons of the three market schemes and their suitability for a country depend on the specific conditions in the country. Country-specific features of high relevance for the design of the market scheme in Egypt are:

1. *There is no political willingness to use public or power sector funds to subsidize windenergy*. This makes the cost-effectiveness of the program – minimization of subsidy cost - a more important determinant for the choice of scheme than the size of or fast growth in installed annual capacity and GWh-output.

2. *For the foreseeable future, there will be a single buyer for bulk supplied power in Egypt*. The tradable green certificate scheme has no relevance for Egypt; it requires a multitude of electricity retailers and distributors who purchase power competitively on the bulk market.[79] The feed-in-tariff and tender schemes, on the contrary, can be introduced for RE-supply without distorting the general logic of the power market and its market rules and procedures.

3. *The best windfarm sites are geographically very concentrated in a few sites along the Gulf of Suez.* If developed fully, the share of windfarm output in the Suez-Hurghada grid will be very high. A large portion of the windfarm output would be transported to demand centers outside that grid. The development of the resources needs careful planning as the national power system must be adapted to be able to integrate a large fluctuating power supply into the local and national grid system. It requires, inter alia, use of sophisticated control systems to be installed at the windfarms, and a better production forecasting ability than is possible with present meteorology- models.

4. *The potential sites for windfarms are on large, coherent areas of land owned by the State.* . The state can control – put an upper limit on – the annual supply of windfarms directly through its decisions on how much new land is to be leased each year. If the allocation of land is decided through a bidding process for individual leases, the state can “price away” the resource rent of each windfarm sites, channelling it into the public budget.

5. *The land at the potential windfarm sites is idle, alternative options for land use are modest or non-existing and there is, very little local population*. Thus, there are no problems with landscape-, noise- or other negative impacts for a local population, which would turn the site approval process into a lengthy affair.[80]

6. *The Government has full information about the quality of wind resources at the individual sites* through its ownership of land, through the Wind Atlas for the Gulf of Suez and through

[79] For this reason, only scarce reference is made to the TGC-scheme in section 6.1.
[80] As mentioned in Chapter 2, the environmental impact on birds needs to be carefully evaluated.

future more detailed on-site wind measurements. The Government does not have to guess what the likely costs of production are for different sites, and thus, what the cost conditions of its windfarm program are for the private investor; it has the same or better information than the private investor who bids for a land lease, or for a PPA. This enables MEE/NREA to forecast with quite a high level of precision the impact of various levels of donor grant support on the size of annual investments in new capacity. The asymmetry in information on cost-revenue conditions between public planners and private investors does not exist in this case.

7. *The high quality of the windfarm sites for the 3500 MW program enables the point of full commercial viability to be reached at a point in the future, depending on the rate of technological progress; yet the difference in annual GWh-output per MW leads to a phased development of the sites*. The estimated annual output of the best site is 25% higher than the estimated output of the worst sites, leading to a range in the year 2004 economic cost of production of 13.3-16.6 piaster per kWh. There are three categories of sites: the very best (1000 MW of Gulf of El Zayt), the exellent (1000 MW of Gulf of El Zayt 2, Zafarana, Ras Ghareb, Ras Suker) and the good (1300 MW of Sant Paul, Ras Bakr and Northe Hurghada). The need for grants can be reduced by developing the best sites first.

8. *According to the analysis of section 3.6 the move towards the fully commercial market passes through two phases: a first phase, where soft loans (with declining scope over time) are sufficient to close the financing gap; and the final "commercial phase"*. The market scheme will, therefore, undergo adjustments from one phase to the next.

7.2.2 Recommended approach: tender scheme combined with feed-in-tariff

The state-ownership of the large wind-sites and their concentration along one single transmission line gives site conditions in Egypt characteristics that are similar to those of "off-shore windfarm sites". The tender procedures for allocating site-leases to project developers will be similar to approaches for awarding licenses /concessions for off-shore windfarm sites used in a number of countries.

A market scheme, which organises annual tenders first for windfarm leases and then for windfarm PPAs, is not efficient: bidders would bid prices for the leases not knowing what PPA-tariff they would get, and the costs of transaction would be high. The approach, which is detailed in section 7.3, uses a single tender process, which merges the best aspects from the tender and the uniform feed-in-tariff-schemes:

- The *uniform feed-in-tariff* is not used as a subsidy instrument; the tariff is fixed at the true avoided cost of 10 piaster per kWh calculated in section 2.2 fore the year 2004. The tariff for the following years is adjusted by a formula according to the development in the average fuel efficiency of stream turbine plants and the international price of crude oil, or of LNG.

- New windfarm sites are put up for *tender* each year; and awarded to qualified bidders according to the offered lease price until the annual quota is allocated.

- If, contrary to expectations, there is a need for a start-up period, where e.g. GEF-subsidies are needed to supplement the soft loans, projects are awarded to the bidders asking for the "lowest GEF-subsidy per installed MW".

The difference between the operation of the market during the commercial and non-commercial periods is summarised in table 27.

Table 27: Market Schemes for Non-Commercial and Commercial Periods

Market Schemes for Non-Commercial and Commercial Periods

Non-Commercial Period	Commercial Period
• Size of market limited by available subsidy amount (donor grants) => need for rationing of project requests • Annual quota system for new MW-capacity or for GWh in PPAs • Tenders are (i) rationing device to allocate the annual quota to project developers and (ii) means to reduce producer's rent. • Bidding for GEF-subsidy (fixed lease price) • Bidding for lease of land at windfarm sites	• No financing limit on size of market as no subsidy is paid • Avoided cost PPA-tariff for new windfarms indexed to variable cost of thermal power • Open-sized annual tenders for leases of land at the large windfarm sites serve as the tool to channel the resource rent into the public budget • Windfarm must be installed on awarded lease within two years. • Developers can develop sites also outside the large windsites

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During the non-commercial period, the size of the annual market is *demand* constrained: the number of MW which is installed depends on how much subsidy money is available and on how big the commercial cost-revenue gap is per MW of capacity. During the non-commercial period, the tenders have two functions: to ration the supply of MW(h) and to reduce the resource rent.

During the commercial period, the size of the annual market is *supply constrained*: the number of installed MW depends on the ability of project developers to identify and develop windfarm sites that are commercially viable receiving the revenue composed of the avoided cost tariff and CO2-payments. In addition, supply depends on the availability of sufficient transmission capacity. If the supply curve shown in figure is to be believed, a demand explosion is not likely to take place when Egypt enters the commercial phase. The cost of production hovers narrowly around the avoided-cost tariff level, as the cost decreases from technological progress are off-set by the lower quality of windresources. There should, therefore, be no need to put a limit on the supply of land in the annual tenders for reasons of coordinated power system planning.

7.2.3 How many MW to include in the tenders?

From an industrial-policy point of view - see figure 8, page 47 – the desirable target is to get at least 200 MW installed per year if the investment is to have a significant impact on the national manufacturing share.

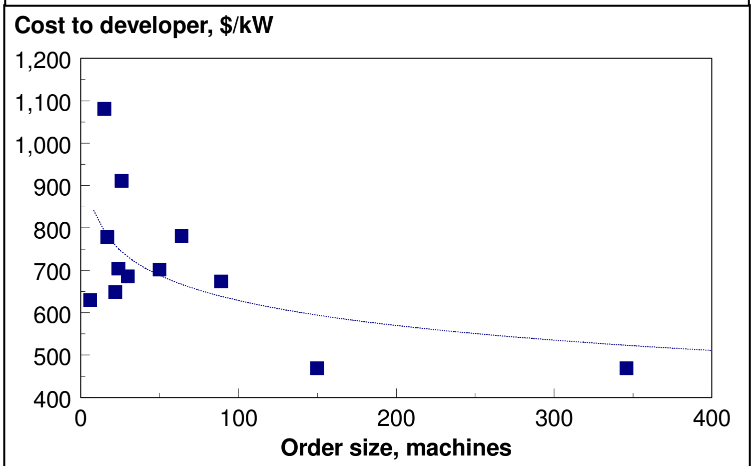
During the commercial phase, on the other hand, it is possible and likely to get more than 200 MW installed.

During the non-commercial phase, the quantity will be lower. The annual MW that can be installed will be determined by the size of available donor grants and the commercial cost-revenue gap per MW of capacity. Under the optimistic assumptions in table 18, page 39, concerning the ability to implement a larger MW-investment program during the non-commercial phase, it will be possible to start with 60 MW in the year 2004, increasing 10 MW a year to 100 MW in 2009, increasing steadily thereafter. The gradual increase in demand facilitates a smooth expansion of the supply capacity in the national component industry.

The Government planners are faced with the difficult decision of deciding on how many individual leases will be put up for tender each year. The Government uses the investment program for the non-commercial phase to develop a national private industry structure for developing and financing windfarms, which is internationally competitive. There is a trade-off between (i) the wish to gain from economies of scale in turbine purchases and in O&M and (ii) the wish to have a number of competing project developers operating on the market.

Figure 20[81] illustrates that considerable price reductions are achieved with very large orders. Yet, in order to get sufficient competition and to test several financing models, the annual tenders must be split up into at least three, and preferably four packages.

Figure 20 Number of ordered turbines and price per MW



[81] Reproduced from paper by David Milborrow, "Wind farm cost and electricity price analysis", 2001

Starting with the 60 MW, the recommendation would be to tender two 20MW and two 10MW land sites. Concerning the latter, bidders can choose whether to bid for 10 MW only or for both sites.

7.2.4 Do you want foreign bidders to participate in windfarm tenders?

The BOOT-regulations, if interpreted correctly, prevent foreign investors from bidding for the windfarm projects. Yet, the pros and cons of inviting foreign bidders need to be spelled out.

Seen through national interest eyes, the participation of foreign investors reduces the number of projects, which national investors can undertake. Ceteris paribus, less national capacity development will take place – although foreign project developers may find it attractive to take loans on the national capital market, and thereby, develop national project financing expertise. Also, even if debt financing comes from national sources, the profit cash-flow will still go abroad. Foreign participation, on the other hand, has the positive impact of increasing competition, not just by increasing the number of bidders, but also the quality – the foreign investors will be experienced. This presses down the price levels for PPAs, or, which is the same, reduces the required subsidy per installed MW. More MW will be installed. The increased competition will force national investors to become internationally competitive if they are to survive as developers of new projects. The impact of foreign bidders on national capacity building, is, thus, not purely negative! There are some dynamic market effects.

If the tenders are reserved for nationally owned and domestically registered companies, the cost of production will be higher, more subsidies per MW are requested and less MW are installed. The profit cash-flow is kept in Egypt, and, presumably, more national players will come up.

A compromise strategy is to limit the tenders initially to domestic investors, and then, as project development enters the commercial stage, to open up for free competition. This permits a national resource base to be developed under "infant industry protection" terms. Yet, it is not protection forever; there is a clear pre-determined exit strategy. Knowing the perspective of free competition, the national industry will be under pressure to become internationally competitive.

7.2.5 How do you get novel financing methods tested in the tenders?

TA will be provided to interested parties in the financial sector and to project developers to develop new financial products, such as the three proposed in chapter 6, and introduce these onto the market as a means to reduce the investor cost of production of windfarms. The intention would be to develop the "revenue bond" and "multiple equity issue" as "on-the-shelf"-products of participating financing institutions. Project developers can pick up these new products as a financing option by taking contact with one of the financing institutions, which will then undertake to make a bond issue or multiple equity issue for the project against a fee.

The price competitiveness of the new products – the transaction costs and the market price of revenue bonds and ownership certificates of the multiple equity scheme- needs to be established in practice. First after having been tested in the market, will the interest of households and other small investors in purchasing the new products be known. It is therefore suggested that the first tender makes it a condition for bidding on the two 20 MW leases that financing is based on either a revenue bond issue or a multiple ownership certificate issue. The bidding for the two 10 MW can be without any financing condition attached to provide for free competition.

7.3 Market Schemes for Non-Commercial Period

7.3.1 Tentative scheme, if supplementary GEF-grant support is needed

The first private investments would be organised for undeveloped lands at the Zafarana site. NREA has the right to the Zafarana site, and will, therefore, be the organiser of the tender for the individual leases and be entitled to receive lease payments from the winning bidders.

The elements of the tender scheme are summarised in table 28.

Table 28: Market Scheme for Non-Commercial Phase 1: "GEF grants"

Market Scheme: Non-Commercial Phase I	
Terms of Tender Package:	Deals concluded by Investor
1. Fixed avoided-cost PPA-tariff 2. One-Year Soft Loan from "host-donor country" for winning EPC-contractor with approximately 30% deduction from principal for end-of-year repayment 3. Price for long term lease of windfarm site fixed at 2% of annual PPA-revenue 4. Bidding for least subsidy per MW from GEF	1. Identifying and negotiating best EPC-contract 2. Negotiating sales price of CO_2-certificates (CER) 3. Terms and conditions of domestic financing package to repay 1-year soft loan

The tender obliges winning bidders of a lease to complete the windfarm within one-and-half years of having signed the lease agreement. As a minimum, the MW-capacity of the installed windfarm must equal the MW-quantity, which is fixed in the tender for the lease.

The *PPA-tariff is fixed at the avoided cost price*, which for a windfarm established in year 2004 is 9.9 to10 piaster per kWh. The avoided cost tariff in the following years will depend on the development in the average energy efficiency of steam turbine plants and on the development in the European market price for LNG (linked to the development in the price of crude oil).

To avoid any discussion or doubt about the additionality of *CO_2-payments for the CERs* of the windfarms, the tenders make it an eligibility condition that a contingent contract for the sales of the CERs for the windfarm has been signed.

It is essential that *GEF's subsidy payments* are reduced to a minimum. The tenders for the land leases will, therefore, be awarded to the developers who ask for the lowest GEF-grant per MW. MW, if installed capacity is larger than the minimum fixed in the tender for the lease, refers to "minimum MW". Technically, in terms of how it functions, the bidding process is very similar to that of a "bidding for lowest required tariff"-tender.

Since the bidding under the tender concerns the size of the GEF-subsidy, not of the lease price, the latter will be fixed in the tender documents. It is suggested to fix the *lease fee at 2 percent of the annual revenue from the PPA*. At a price of EGP0.099 per kWh, and an annual average output of 3,942 MWh/MW as forecast by NREA, the fee would provide NREA with an annual revenue per installed MW of EGP0.39 million, equal to US$70,000.

A *one-year-soft donor loan* is part of the financing terms offered by the published documents for the tender. A substantial deduction on principle is needed to reach the 35% grant element required of soft loans according to the terms fixed in the OECD agreement on the matter. The deduction will be around 30 percent, meaning that only 70% of the soft loan has to be repaid.

The ability of a bidder to compete depend on his skills in (i) negotiating the price for the EPC (turn-key) contract, (ii) negotiating the price per ton CO_2, and (iii) putting together a low-cost project finance package on the national capital market to repay the soft loan at the end of one year.

Beginning in 2007, the tender will be for public land not owned by NREA, and on a site other than Zafarana. MEE must decide (i) which windfarm site will be developed next after Zafarana, and (ii) which institution will be in charge of the tender, as NREA is no longer in possession of the rights to the wind farm leases.

7.3.2 Scheme for non-commercial period, Phase II: soft loans only

When no supplementary grants are needed, the tender changes to a “bidding for highest lease payment” scheme.

Otherwise, the terms and conditions of the tender are unchanged, see table 29.

Table 29: Market Scheme for Non-Commercial Phase II: Soft Loans only

Market Scheme: Non-Commercial Phase II	
Terms of Tender Package:	Deals concluded by Investor
1. Fixed avoided-cost PPA-tariff	1. Identifying and negotiating best EPC-contract
2. One-Year Soft Loan from ”host-donor country” for winning EPC-contractor with approximately 30% deduction from principal for end-of-year repayment. Scope of EPC-contract covered by loan declines over time.	2. Negotiating sales price of CO_2-certificates (CER)
3. Bidding for highest price for long term lease of land at tendered windfarm site	3. Terms and conditions of domestic financing package to repay 1-year soft loan

7.4 Market Scheme for Commercial Period

Once the commercial phase is reached, the LRMC-supply curve for the 3500 MW windfarm program in figure 6 on page 38 shows that the viability and scope of the national market depends on continued progress in the productivity of new windfarms to offset the decline in the quality of the wind regime at the sites. Due to the declining quality of windfarm land, there will be no investments bonanza. It is more realistic to expect a relatively smooth development.

The situation opens a number of questions.

One is whether MEE should *restrict the amount of leases of state-owned land that are put up for tender each year*? The alternative is to *organise a tender per year and invite bids for leases of land, letting the total amount of leases be decided by the prices that are offered:* bids with low prices are rejected, all other bids are accepted. The recommendation is to start with open-ended tenders, evaluate what happens and change the approach to a pre-planned number of sites if the situation warrants it. If, due to a strong decline in the prices of windturbines, spontaneous demand jumps up and through the increase in intermittent power supply gives the power system absorption problems, MEE can regulate the annual supply by limiting the number of leases that are put up for tendering.

The other is whether MEE should authorize windfarms to be developed outside the eight large "official designated windfarm" sites. In principle, such a move could stabilize the growth – or level - in annual demand when development turns to the lowest of the three wind categories. If pockets of "in-between" sites with favourable wind regimes can be developed, that will help the national windfarm industry. Yet, in view of the rather important scale economies in windfarm investments one may question whether sizes of sufficiently large size can be found to be competitive.

Table 30: Market Scheme for the Commercial Phase

Market Scheme: Commercial Phase	
<u>Standard Terms for Investors:</u>	<u>Deals concluded by Investor</u>
1. Fixed long-term PPA-tariff. The tariff for new windfarms may change upwards or downwards depending on evolution in long-term international price of oil/LNG and productivity increase in new thermal power plants	1. Bid on land leases for windfarm sites developed by NRREA/MEE or negotiate land lease deal for site identified by investor 2. Identifying and negotiating best EPC-contract 3. Negotiating sales price of CO_2-certificates (CER) 4. Terms and conditions of domestic project financing package

The tender procedure in table 30 has become truly commercial. There is no longer a financing package included in tender. Windfarms can be offered the choice between signing a 20 year PPA with fixed tariff, or to operate on a “merchant plant” scheme, selling into power pool, if the single buyer scheme has been abolished by then.

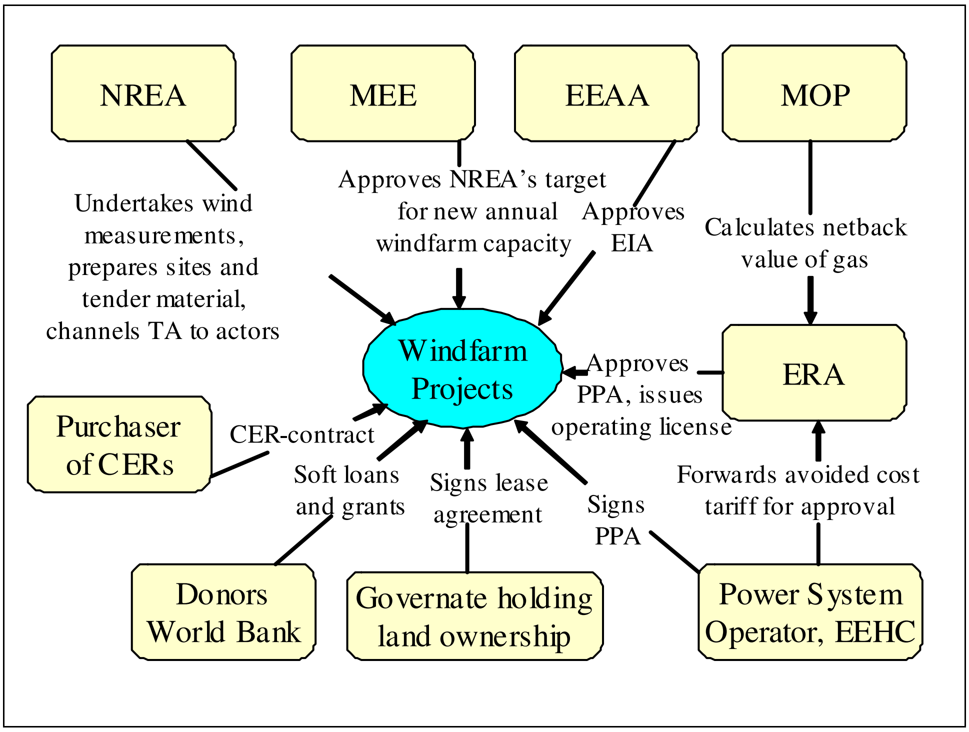
8 REGULATORY AND INSTITUTIONAL FRAMEWORK

8.1 *Institutional Responsibilities*

8.1.1 Overview

The institutional responsibilities for the windfarm program could be organised as shown in figure 21. In this, nine public institutional actors are identified, each with his specific role, and two private.

Figure 21: Institutional Responsibilities for Windfarm Program



8.1.2 Setting quantitative targets for the windfarm program

MEE has the political responsibility for setting the quantitative goals for the windfarm program, expressed in the form of 20- and 5-year targets. During the non-commercial period, the quantitative goals depend on the availability of donors grants and loans, the size of which, at least up a certain limit, is influenced by the policy wishes of MEE, formulated as official Government policy.

MEE's policy papers would be written in close consultation with *NREA* – which would be expected to provide required background information and write draft policy papers as input for MEE – and with *EEHC as national power system operator*. *ERA* could be consulted also.

8.1.3 Preparing windfarm sites for tendering

NREA has the overall organisational responsibility for preparing the windfarm sites for tendering.

The preparation of the windfarm sites requires the following:

- Land clearance, including mine clearance
- Getting the planning permit from the pertinent national authority for using the land for windfarms
- Getting the EIA approved
- High quality program of measurements, at least four years from a mast for the whole site area as such – e.g. Zafarana – and at least one year of measurements at each tendered plot.
- Preparation of feasibility study for investments on the tendered plots
- Preparation of tender documents, including all draft legal documents

NREA identifies which state-owned project sites are to be tendered according to a time plan agreed to by MEE after consultation with EEHC.

NREA hires contractors to do the clearing of land for mines and the Institute of Meteorology to undertake a high-quality wind measurement program at the site.

NREA gets the planning and windfarm development permits for the sites from the pertinent national authorities.

NREA contracts consultants to prepare the EIA for the sites, and other consultants to do a financial feasibility study for the sites to be tendered. The feasibility study would be done on the basis of an indicative plan for micro-siting done by NREA and output estimates that result from the application of collected wind data to the power curves of a selected "pro-forma" wind turbine. The feasibility study gives information about the likely level of required prepares tender material and assists in negotiating the detailed terms with the winning bidders – in particular, when competition is insufficient. It will be part of the tender information material provided to investors.

NREA prepares the tender documents for the published tender, and hires lawyers to draft the standard legal forms for the contracts to be signed with the winning bidders.

8.1.4 Implementing the tender

NREA is responsible for issuing and carrying out the tenders for all plots at the Zafarana site. Once the Zafarana site has been fully developed, the Government (MEE) must decide whether:

- NREA will continue to publish and implement the annual tender, or
- the tender is to be issued in the name of MEE, or

- the tender is to be held by EEHC’s National Transmission s Company / System Operator, or
- the tender is published jointly in the name of all three organisations.

The implementation of a tender comprises the following:
- Publishing the tender
- Evaluating the bids
- Selecting the winners
- Signing of land lease
- Signing PPA with winner
- Signing GEF-subsidy award contract with winner
- Issuing operating license to winner

NREA could in all cases be the consultant for evaluating the bids, and writing the evaluation report, evaluating the financial and technical capacity of bidders, in addition to the price offer. The winner would be picked by the institution publishing the tender. The land lease with the winner is signed by the national institution, having the ownership responsibility on behalf of the State. EEHC’s Transmission Company/System Operator signs the PPA with winner. ERA issues the operating license to the winner. GEF procedures identify which institution is authorized to sign the GEF subsidy award contract.

The land lease would require the project developer to install his windfarm within one-and-a-half years after the lease is signed and be required to deposit a performance bond.

8.1.5 Signing the soft loan

Project developers can chose to organize a contingent tender for the EPC (turn-key) -contract before the tender, or hold the EPC-tender after a tender for a lease has been won.

The soft loan for the EPC-.contract could be signed with KfW, with Danida or with Spanish soft-loans.

Depending on the agreements reached between MEE/NREA and donors, the three donors could agree to provide their loans on a fully unbound basis for specific leases. For example, if three leases are tendered, each donor could agree to finance the EPC-contract for one of the three leases. The EPC-tender for the site organised by the project promoter would determine, whether the turbine supplier happens to come from the country providing the loan, but have not influence for the loan; it will be awarded in any case. The liberty to make an open world-wide tender for the EPC-contract would be stated in the tender documents.

An alternative would be that the tender documents authorize project developers to organise a tender which is limited to turbine suppliers from the three donor countries, and that each donor finances only the contracts being awarded to turbine manufacturers from the home country.

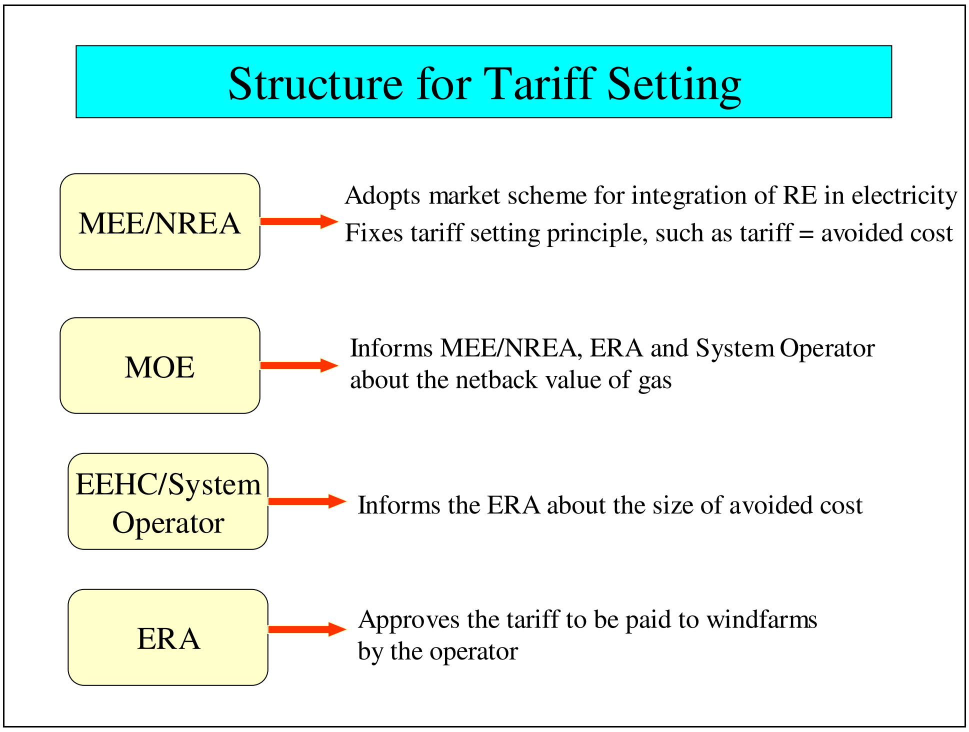
8.2 Framework for Regulation

8.2.1 Tariff policy for windfarm PPAs

A long-term tariff regime with well-defined rules for price setting and providing long-term stability in prices is an indispensable prerequisite for securing "low-cost" commercial finance and for attracting private investors to the sector. In Spain, for example, the annual adjustments of Spain's two subsidy mechanisms[82] are the major reason for the "high-risk" rating of BBB- to BB+ by market analysts Standard and Poor (S&P).[83]

The framework for setting the avoided cost tariff is summarised in figure 22.

Figure 22: Structure for setting the avoided Cost Tariff in Windfarm PPAs



The PPA will be for a 15 or 20 year period. Technical questions to decide are:

1. *Whether the PPA-tariff signed with new windfarms in a given year should be fixed in nominal terms for the whole 15-20 years or be adjusted each coming year according to an index*, and if yes, what kind of index?

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[82] Producer's can chose between two tariff options. One is a kWh-production incentive, which is paid by distributors in addition to a rate based on the average electricity pool price. The other is a fixed tariff throughout the year, which

[83] Wind Power Monthly, June 2003:"Industry fears dip in investor confidence".

One option is to link the PPA to the *rate of inflation*. Since the PPAs are signed for 15-20 years, investors need to have some degree of protection against long-term inflation, in order to be able to cover their costs with the revenue. Since windfarms are capital intensive, most annual expenditure consists of payment of interest and repayment on principle. Since loans are fixed in nominal terms, there is no need to inflation adjust for this expenditure item. The inflation adjustment formula would be for a part of the PPA-tariff, equivalent to the average share in total windfarm cost of production that is made up of O&M-costs.

The other option is to insist in the *sharing of market risks*. In this case, instead of looking at the protection of the economic interests of the windfarm investor, one looks at the protection of the economic interests of the single buyer, and more precisely, at protecting the interests of electricity consumers. The PPA-tariff is based on the avoided cost of the power system, which consists mainly of the economic value of saved gas consumption, a minor part is for capacity value and for non-fuel O&M. One can, therefore, design a indexation formula with reference to these three cost items. The economic value of gas depends on the evolution in the price of LNG exports to the European market; its share in the PPA-tariff valid for a year at a time can be indexed to the average LNG-price (fob) on the European market during the previous year. In addition, the formula for the value of replaced can be coupled to the average fuel efficiency of steam turbine plants during the previous year.

2. Should MEE/ERA, for reasons of long-term information to investors, publish a baseline PPA-tariff with an automatic adjustment formula, to be used for all upcoming windfarm PPAs for a specified number of years, e.g. five years? At the end of the period, MEE in consultation with ERA and EEHC would fix a new pluri-annual baseline tariff, to be used for future PPAs with windfarms.

8.2.2 Dispatching Rules

MEE/NREA will negotiate with ERA and EEHC to get favourable dispatch rules adopted by the national system operator/transmission company (ISO). The viability of windfarms is strongly influenced by rules from the ISO that penalize intermittent resources for imbalances and their inability to guarantee scheduling of output ahead of time.

8.2.3 EIA approval

The EIA, depending on consultations with EEAA could be done in two stages.

First, a strategic environmental assessment (SEA)[84] is prepared for the windfarm program as a whole, comprising the development of the eight identified windfarm sites.

Then an EIA is prepared for the windfarm site, which is next in line for windfarm development.

If needed, the EIA for the windfarm could be sub-divided into the individual plots that are put up for tendering.

[84] The definition of SEA under ”abbreviations, acronyms and definitions”.

The SEA and EIAs prepared by consultants are forwarded by NREA to EEAA for approval.

8.2.4 Connection and transmission charges

MEE/NREA will negotiate with ERA and EEHC the terms for the connection fees charged by the national transmission company for connecting windfarms to the grid. The cost of transmitting the power to consumers is reflected in the level of the avoided cost tariff for the PPA.

8.3 Restructuring of NREA

The dual role of NREA as (i) Renewable Energy R&D&D Institute and (ii) wind farm developer, owner and operator is not natural. It is born out of the necessity to find funding for NREA. The profit revenue from the windfarms was to provide NREA with the necessary income to cover the non-funded costs of its operation.

The proposed scheme for private investments in windfarms takes care of NREA's funding problem. The lease fee for land at Zafarana, if fixed at 2 percent of the PPA-revenue of the developer, will, provide NREA with an average annual lease income of EGP0.4 million per installed private investor owned MW.

It is recommended to reorganize NREA as a Commercial Holding Company with two sub-companies:

1. Renewable Energy R&D&D Institute financed by
    i. Basic funding allocation from the annual profits from windfarm operation and from annual lease revenue from the Zafarana private wind farm sites
    ii. Fees for preparing project sites and tender material
    iii. Research contracts with MEE and other Government institutions.
    iv. Consultant fees for private investors and for assistance to donor financed energy sector programs

2. Wind Farm Company
    i. Operation of the NREA-owned wind farms at Zafarana
    ii. Administrator of the land leases at Zafarana, receiving the lease revenue.

An alternative is to separate wind farm operation from the administration of the land leases, setting up a third Windfarm Land Leasing Company under the Holding Company umbrella.

9 PARTNERSHIP PROGRAM FOR NON-COMMERCIAL PERIOD

9.1 Strategy for Implementation

9.1.1 Preparation of action plan for the development of windenergy

The rich wind-resource potential in Egypt and continued cost reductions allow windfarms within a few years time to become an economically competitive generator of electricity for 5-10 percent of national electricity supply. But unless a number of energy pricing, financing and regulatory barriers are removed, windfarms will even then not be a commercially viable investment opportunity.

Decision taking by Government and Parliament on the removal of the barriers requires the presentation of a well-argued national policy, strategy and action plan for the development of windenergy in Egypt. This report is a small step towards its preparation. The elements of the recommended reform package must be refined and internalized in the national policy process by working groups that in response to TORs prepare concrete policy proposals and legal texts for political decision taking. It is recommended to NREA/MEE to set up five working groups:

1. A working group to confirm the avoided costs of thermal power, and the likely year of economic break-even. This group would be composed of staff from NREA, EEHC and ERA.

2. A working group to discuss realistic cost-effective options for the financing framework for windenergy. This group would be composed of staff from NREA, Ministry of Finance, Central Bank, ERA, commercial banks, Bank of Egypt.

3. A working group to recommend the regulatory-institutional framework for investments in windfarms. This group would be composed of staff from NREA, MEE, ERA, EEHC.

4. A working to discuss the removal of energy pricing barriers to windfarms comprised of staff from NREA, MEE, MOO, Ministry of Finance.

5. A working group to discuss the employment and foreign exchange benefits of windenergy and cost-effective, economically rational instruments to maximise the national value-added of windfarm investments. This group would be composed of staff from NREA, MEE, Ministry of Industry, Ministry of Planning and Economic Development.

A core windenergy policy team would use the output of the four working groups to define an action plan for the long-term commercial development of windenergy in Egypt.

The setting up of cross-sectoral working groups serves the objective of technical quality. An essential side-benefit is consensus building on the benefits and costs of windenergy and on proposed policy instruments.

In parallel with the technical work process, the Government would seek to secure the active collaboration of key stakeholders in the implementation of the action plan: commercial banks, EEHC, ERA, bilateral donors, World Bank/GEF, private developers.

9.1.2 Contacting potential developers and financing institutions

Potential developers of windfarms in Egypt are:

1. *NREA*, the traditional windfarm investor. NREA has the technical experience in preparing, implementing and operating windfarms. But seen through the eyes of a commercial banker, NREA, being technically bankrupt/insolvent, is not a creditworthy stand-alone developer. Having NREA as minority co-investor, instead, alongside a creditworthy majority equity owner, would be an asset, reducing the technical-operational risk of a windfarm project.

2. *EEHC*, either its transmission/system operator company or one of its regional distribution companies. Being an electricity utility, EEHC is a credible technical operator. But the financial position of the individual companies may not be strong enough to allow "balance-sheet"-financing and therefore benefiting from the interest-rate advantage this entails.

3. *A private company operating in related industries*, such as civil and electrical construction, or in large-scale commerce. These companies are weaker in technical windfarm-knowledge but stronger in commercial-financial standing.

In the leading windfarm countries, Denmark, USA, Germany and Spain, investments in large-scale windfarm are undertaken by utilities and by private project development companies. *Utilities* have a comparative advantage as they, normally, use balance-sheet finance for windfarms. But *private developers* are essential for long-term stability of investment. Windfarms are a side activity for major utilities. This makes the level of windfarm investment of a utility very sensitive to changes in its cash-flow situation and strategic shifts in short-term priorities. Private developers tend to set up a specialised division for the purpose, whose modus vivendi is to create new projects. It would, therefore, be rational also in Egypt to encourage the entry of both types of investors.

Since the cost of capital is not known – depending on the market's reaction to the new financial products – and windenergy is virgin territory, it will be difficult to get *private entrepreneurs* to bid for a windfarm project without a heavy risk premium in terms of required subsidy support or level of PPA-tariff. Therefore, despite the intuitive appeal of picking winners by competitive tenders, it may for the first projects be more cost-effective for NREA to make a call for expressions of interest from private entrepreneurs. NREA in consultation with NER can negotiate with the most credible of interested private companies their terms for participating on a cost-shared basis in implementing a windfarm project, and thereby identify and conclude the most attractive deal.

The same approach would be used to identify the *collaborating financial institution* for channelling the soft loan to the investor and for preparing the bond and equity issue. The Bank of Egypt, the traditional lender to NREA's windfarms lacks the commercial orientation for fulfilling the function. Among interested and qualified private banks, the one asking for the lowest fee-rate for doing the job would be chosen.

9.1.3 Sequencing

The analysis in chapter 6 shows that the present financial framework does not enable private investors to offer windgenerated electricity at attractive prices. The PPA-tariff – or investment subsidy per MW – resulting from private tenders would be too expensive and send the wrong signal on the true cost of windenergy.

In view of this, the first priority is to get financing innovations at least partly in place before it makes sense to bring in a private developer. Getting a private developer on board for the windfarm project is desirable, but less essential than getting a collaboration agreement with a private bank for testing the market for windfarm equity and revenue bond issues. The financing modality as such can be tested equally well through a project implemented and owned by either an EEHC-owned utility or by NREA. NREA can be the owner-operator of last resort, unless the commercial banks refuse to lend to NREA for being financially too weak.

9.1.4 Market testing of revenue bond and equity issues

The development and testing of the new financing instruments requires the conclusion of five agreements.

At least one of the bilateral donors, who provide soft loans to investments in windfarms, must agree to provide the soft loan to the "financial pilot windfarm" as a one-year loan.

A private *financing institution* must agree to channel the soft loan to the investor and to participate in the active development of new long-term financing and in testing the reaction of the markets to these new financing instruments.

A *donor, preferably GEF,* must agree to finance the TA to the financing institution and to co-fund the development costs of the product and the marketing campaign for the bonds and ownership certificates.

Someone must agree to *underwrite the bond or equity issue*, which means agreeing to purchase at a pre-determined price all that is not sold to the public. In theory, ideally, the financing institution would do the underwriting. In practice, it is more realistic to expect that NREA/MEE can negotiate an agreement with *EEHC* for this, in particular, if EECH (or its transmission company or one or more of the distribution companies) is offered to be the investor-operator of the windfarm.

ERA and EEHC subscribe to the proposed principles and formula for setting windfarm PPA-tariffs

9.2 Collaborating Role of Donors

The implementation of the windfarm investment program during the "non-economic period" depends on the Government's ability to reach agreement with donors on their contribution:

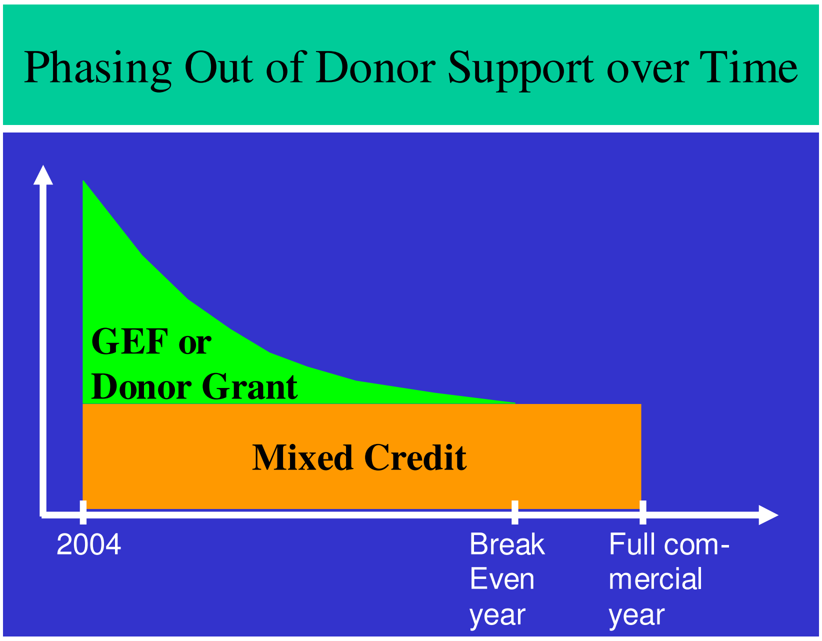
- that bilateral *donors* agree to implement the proposed changes in the funding modalities for soft loans and to accept open tenders for windturbine suppliers;

- that *World Bank/GEF* agree to fund TA and "topping-up" investment subsidies during the initial years, when the grant element of the soft loans is insufficient for commerciality.

9.2.1 Soft loans and topping-up investment grants

During the first years, as shown in Figure 23, the soft loans provided by the bilateral donors – Denmark, Germany, Japan, Spain – do not fully reduce the gap between the economic cost of windenergy and the economic value of the avoided costs of thermal power. To make the projects economically viable for Egyptian society, a topping-up grant is needed to close the economic cost-benefit gap.

Figure 23: Phasing out of Donor Subsidy Support over Time



The *national funding option* is to offer windfarms implemented during the non-commercial period a PPA-tariff, which is higher than the avoided cost tariff. Such a scheme could upon adoption (i) be limited in duration for specified number of years; (ii) have fixed rates for the PPAs signed during that period, which decline each year, and (iii) are valid for a defined number of MW of new windfarm capacity each year. In view of the political skepticism, which still surrounds wind energy in Egypt, and which can only be broken by the successful implementation of the program and demonstrated annual cost reductions, this option may not be politically possible.

The alternative option is to *ask GEF to provide topping-up investment grants*. GEF has been careful in staying away from co-funding CDM-projects. But as the Egyptian approach would be a clear case of barrier-removal with a well-defined exit strategy, be limited in time with declining rates each year, it may be politically possible for GEF.

9.2.2 Technical Assistance to market participants financed by GEF

The establishment of the market scheme for wind energy in Egypt requires product development in the financial market and working out of the details for the institutional and regulatory framework. This is a consultant-intensive process and needs to be financed.

GEF/World Bank is the ideal collaborating partner for providing TA. First, the bilateral funding agencies, providing the soft loans, do not have grant funds for major TA. Second, GEF is a neutral, honest broker, whereas, the bilaterals have export interests, which risk to influence their TA.

The GEF funded TA-package could have the following scope:

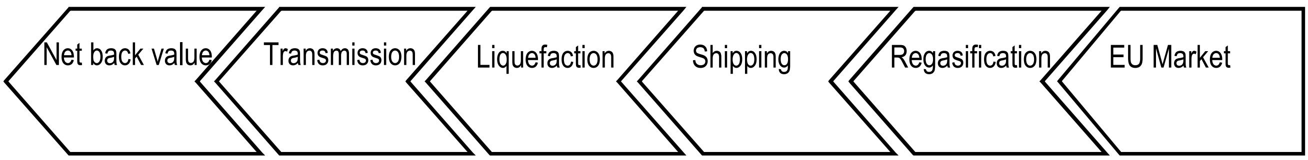
- TA to NREA/MEE in formulating the national policy and action plan for the windfarm program.
- TA to NREA/MEE/ERA in developing the rules and regulations for tender procedures during the "non-economic period" and the later "fully commercial period".
- TA to ERA in developing the formula for the avoided cost tariff.
- TA, on a cost-shared basis, to the national financial sector in developing revenue bonds and ownership certificates issues, including the implementation of marketing campaigns for selling the issues to the general public
- TA, on a cost-shared basis, to potential project developers in how to enter the business.
- TA to EEHC in dealing with the integration in the national power system of the large amounts of intermittent power supply coming from the estimated 3500 MW of windfarms; in developing dispatching rules, in establishing appropriate cost-based pricing of services for interconnection.
- TA to NREA/MEE in defining rules and instruments for the maximisation of national economic benefits from the windfarm investment program.

ANNEXES

I. Net-Back Value of replaced Gas

In Egypt, wind power substitutes thermal power generated on natural gas. One main question is: What is the economic value of the gas not used, as a result of increased wind power production? The economic value of natural gas consumed at power stations in Egypt is equal to the net-back value of liquefied natural gas (LNG) exports from Egypt.

The calculation of the net-back value of LNG assesses the LNG export chain. From the market value at the export market – most likely in EU – backwards in the process of treating and transporting the LNG:



Exporting of natural gas as LNG includes 5 main stages in the LNG-Chain:

- Gas production (or purchase of gas from producers)
- Transmission to the export harbour
- Liquefaction of the gas
- Loading and ocean transporting
- Reception and regasification

To quantify the economic value of gas, the EU market prices of LNG are assessed. However, these are and will for many years still be dominated by a price link to globally traded crude oil. This chapter presents the range in which oil prices have developed during the last years, and presents the main oil price forecasts for the period until 2020. Based on these, the price link to LNG is calculated based on statistical regression on the relationship between oil prices and LNG prices. Furthermore, the costs in each of the export segments are analysed. Based on the analyses presented in this report, the future net-back value of LNG are in Egypt in the range of 1.5 USD/MMBtu (at an assumption of a future oil price in the range of 21 USD/bbl).

The assessment is based on an assumption that EU will be an importer of Egyptian LNG. Therefore are the current and expected EU gas need and import strategies presented. The fact is that the European gas demand increase, at the same time as the domestic production declines – Preparing for a large increase in imports, and in particular via LNG. The rapid growth of LNG imports to EU corresponds approx. to 2½ bcm more per year. This is almost the same as one small LNG export train extra per year to secure the increases in the EU demand.

The net-back value of LNG is an economic value. But how can it be converted into support for wind projects. Actually, initial steps have already been taken in Egypt. The two involved ministries, Ministry of Petroleum and Ministry of Energy, have agreed to establish a Fund for green energy, which partly sponsors future renewable and wind energy projects based on income from a special gas export levy. Especially wind energy projects are aimed to receiving support, since these projects directly, via increased power production, substitute gas-fired power, and thereby release extra volumes of gas for export.

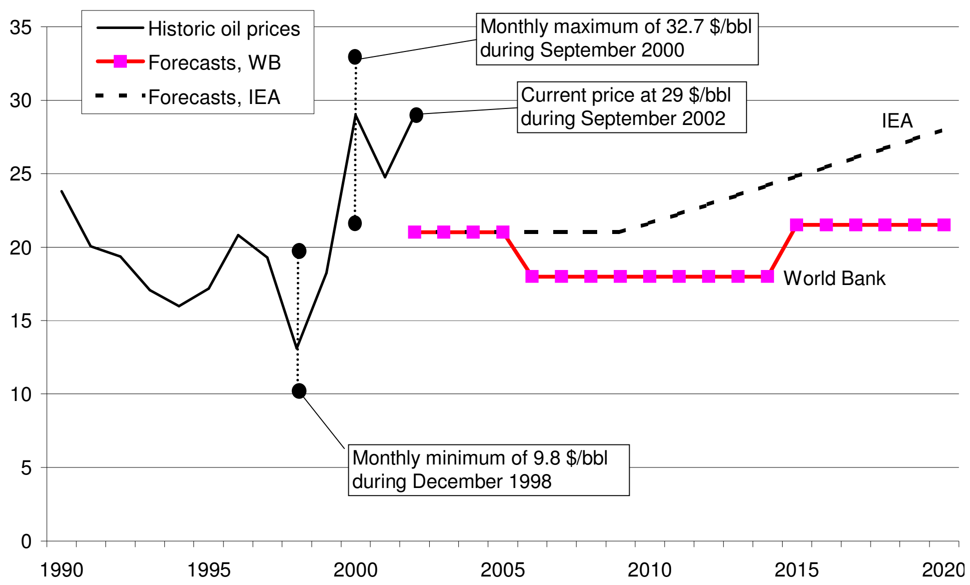
1. LNG Chain: Oil prices - history and likely future levels

During the last four years, the monthly Brent crude oil price has experienced a variation between 9.8 and 32.7 USD/bbl. Seen in a longer perspective of 10-50 years the variation of these last four years contains the total historic volatility of the world oil market. If one assesses the daily oil price variation, an even wider spread is registered with a 50-year low at 9.1 USD/bbl early in December 1998.

The latest oil price forecasts from the main international institutions are:

- The World Bank expects 21 USD/bbl from 2002 to 2005; falling to 18 USD/bbl until 2014, increasing to 21.5 USD/bbl[85];
- The International Energy Agency expects 21 USD/bbl until 2009, and between 2010 and 2020, the price increases steadily to 28 USD/bbl[86].

Figure: Forecasts of oil prices



In average, both forecasts expect a future level around 21 USD/bbl.

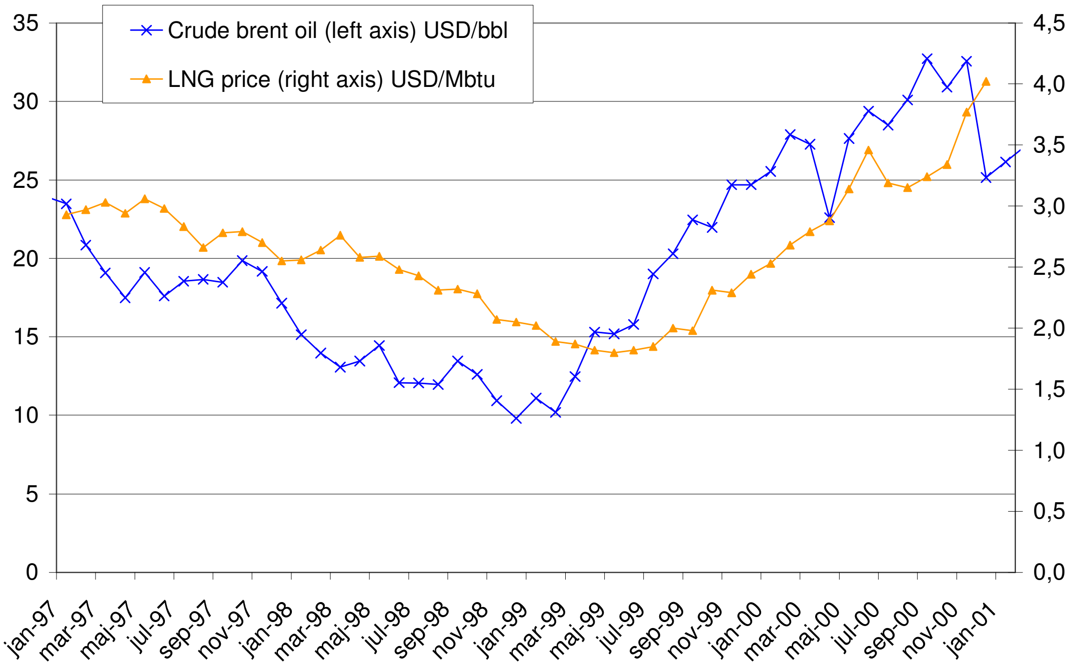
2. LNG Chain: The EU market value of LNG

[85] Recent assumption in macro-economic analyses performed under the World Bank project "Energy Sector Technical Assistance Project in Kosovo" (2002)

[86] International Energy Agency "World Energy Outlook 2000" (2000)

The importance of oil prices is not limited to the oil sector and the use of oil. Currently, both natural gas and LNG prices are, globally as well as in Europe, (including the supplying countries in Northern Africa) closely linked to a basket of mainly oil products via the long-term take-or-pay supply contracts. This results in a gas and LNG price variation matching that of oil. Even though all contracts are more or less individual and confidential they all include the same underlying mathematic linking to oil prices. The gas and LNG price in one period is often directly calculated as a linear combination of oil prices from i.e. 1, 3 or 6 months ago.

Figure: Link between the oil price and LNG price



Based on statistical assessments of the average European oil and LNG prices, the best correlation is obtained with a 6-month lag in oil prices – reaching 90% description of data:

LNG price in USD/MBtu = OIL price in USD/bbl x 0.094 + 0.87

At an oil price of 21 USD/bbl, the corresponding LNG price becomes: 21 USD/bbl x 0,0944 + 0.8671 = 2.8 USD/MBtu. Using the future oil price projections of 18 – 28 USD/bbl, the future EU LNG price will be around 2.6 – 3.5 USD/MBtu.

There is a trend in the LNG business towards greater flexibility. This appears from the fact that more LNG is sold as spot sales, and less as long term contracts with high fixed prices. The short-term sales take a larger par of the LNG market, but there are only a few takers available to handle short-term purchases.

3. LNG Chain: Shipping

The transportation costs of LNG are directly related to the distance between the two harbours. The Ministry of Electricity and Energy estimated the shipping costs to be around 0.25 - 0.30 USD/MBtu. EGAS commented that these shipping costs were in the low range referring to the fact that it depends on the location of the receiving country/terminal. Instead they proposed a shipping cost in the range of 0.3 – 0.5 USD/MBtu.

Based on RAMBOLL in-house data, the shipping cost of transporting gas from the Egyptian Mediterranean Coast to France is just above 0.4 USD/Mbtu.

In the same way as the pipeline transportation costs the shipping costs depend on the distance of the transportation. The table below shows the cost of transportation from Egypt to several destinations in Europe and US, based on the calculations using the formula mentioned.

Table: LNG transportation costs

		Distance (approx.)	Shipping costs
From	To	Km	USD/MBtu
Egypt	Italy	2200	0.36
	France	2860	0.43
	Spain	2860	0.43
	Belgium	6000	0.73
	US	9250	1.05
	US/T&T	2650	0.41

LNG Ships only make up a small world fleet, as they are highly specialised ships, designed to hold their cargoes just below -l60°C. Previously, the number of ships was closely linked to the individual LNG project, since the costs of ships was seen as part of the entire LNG project, using a long term take or pay contract, including use of the ship solely for the specific project. However, at a certain phase in the development, ships are no longer considered fully integrated in the total investment, but seen more in parallel to the ordinary shipping traffic. New vessels are still being built to serve dedicated routes and have a capacity of around 130 000 cubic metres.

4. LNG Chain: Liquefaction

The heart of the LNG process is the cooling and liquefaction. This is usually conducted in two stages by heat pumps that work on the same principle as a domestic refrigerator. The temperature is reduced to around -30°C in the first cycle, and in the second to -l60°C. The gas is reduced in volume by a factor of 600. This process requires vast quantities of cooling water and consumes the majority of the plant's energy requirements - representing some 12% of the incoming gas.

For LNG it is particularly important to remove acid gas and water since these substances become solid at LNG temperatures and therefore must be removed to avoid clogging. In the same way heavier hydrocarbons that freeze at LNG temperatures must be removed. These (butanes and pentanes) can be sold separately as liquefied petroleum gas (LPG).

LNG plants function more or less continuously, while ships arrive at intervals of two to three days or more. The liquefied gas is therefore transferred to insulated holding tanks to await shipment. The size of the storage (number and size of these tanks - typically 60 000 to 100 000 cubic metres each) depends on the frequency of ship loading.

The Ministry of Energy and EGAS, supported the international level of Liquefaction costs at around 0.9 USD/Mbtu.

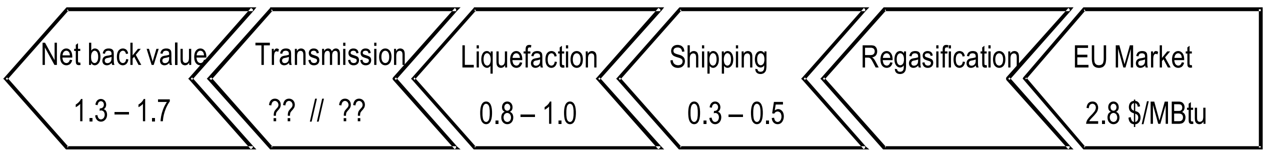
5. LNG Chain: Transmission in Egypt

The net back value includes two potential transportation cost components. One is the actually used transmission cost for gas transported in the EGAS transmission system, from the producing areas to the power plants. Secondly the future LNG export may use and pay for the same transportation service via a full cost reflecting methodology. However, as these two costs components are vitiated by large uncertainties, and because the costs are estimated to be of little value, they are not included in the assessment.

An example of the ambiguity is the fact that the LNG terminal is likely to be closely linked to the production of gas. Both facilities could be owned by a foreign owner, and not interconnected to the national gas grid. This indicates that no transportation tariffs should be paid to EGAS. However, many examples exist throughout Europe where the gas transportation company always has the right to construct the pipeline(s) – and thereby also the option for tariffing a cost.

6. Results

Based on the above assessment, the full LNG Chain can be presented. It should be noted that the LNG market value in EU is CIF, and therefore not including any regasification costs:

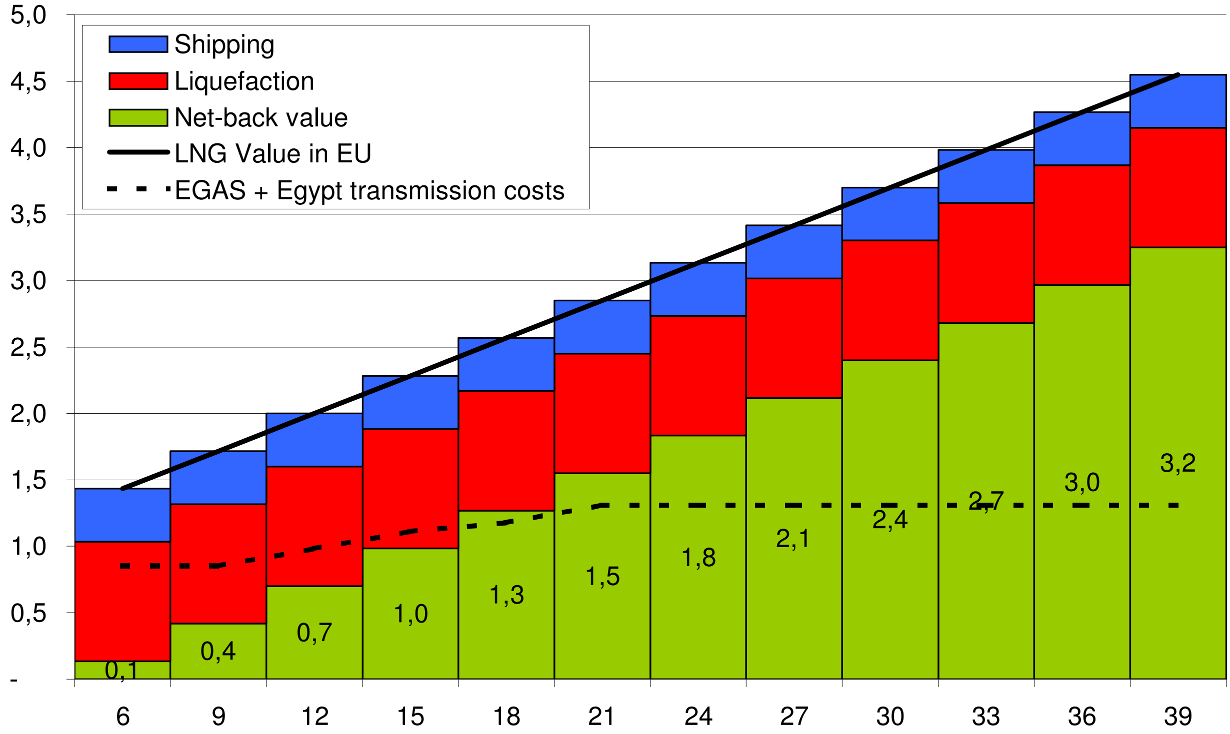


At a future oil price of 21 USD/bbl, the net-back value of LNG from Egypt to EU is between 1.3 – 1.7 USD/Mbtu – Average of 1.5 USD/Mbtu.

The graph below presents the net back value at different oil prices – Presented by the green area. At oil a price of 18 USD/bbl the net-back value is 1.3 USD/Mbtu.

The production costs of gas under the different EGAS production sharing agreements average 1.05 USD/Mbtu (at an 18 USD/bbl oil price) – Presented by the dotted line. Based on a general European tariff method, one average m³ of gas transported 2-300 km would in Eqypt result in a 0.25 USD/Mbtu transportation cost. Together the total costs in Egypt are 1.3 USD/Mbtu.

Hence, the delivery costs of one m3 is exactly the same as the net-back value – Making 18 USD/bbl the break-even price for whether it is economically and financially feasible to export LNG from Egypt. At higher oil prices it is economic – and at lower it is not.

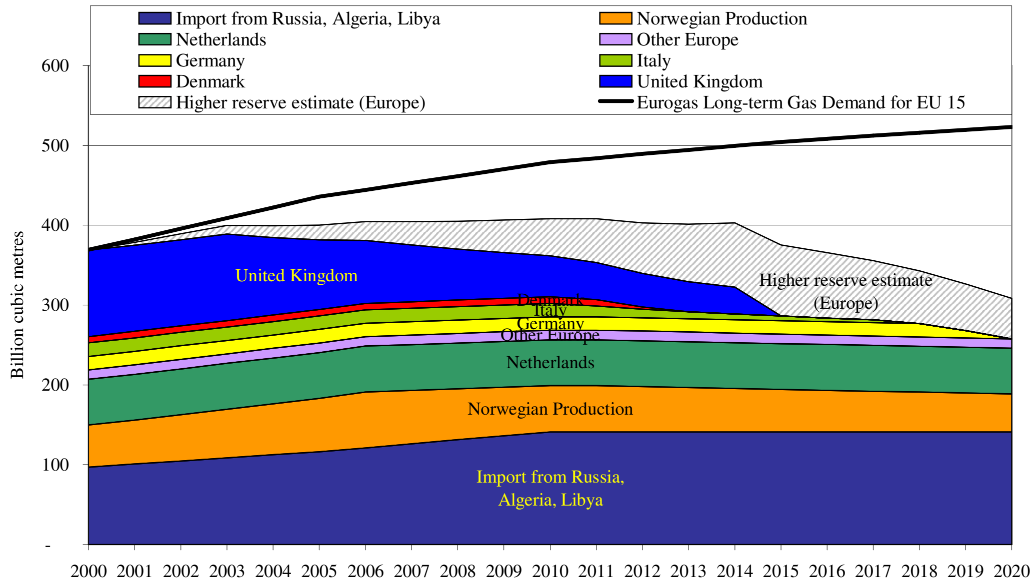


7. LNG as import option for the EU

(a) EU's future gas demand

The EU gas consumption is expected to increase from the current 370 bcm a year to 530 bcm during the next 20 years. The domestic production will decline together with a depletion of reserves – reducing the contracted supply down to 330 bcm by 2020. This is a lack of 200 bcm by 2020.

Figure - Future gas demand

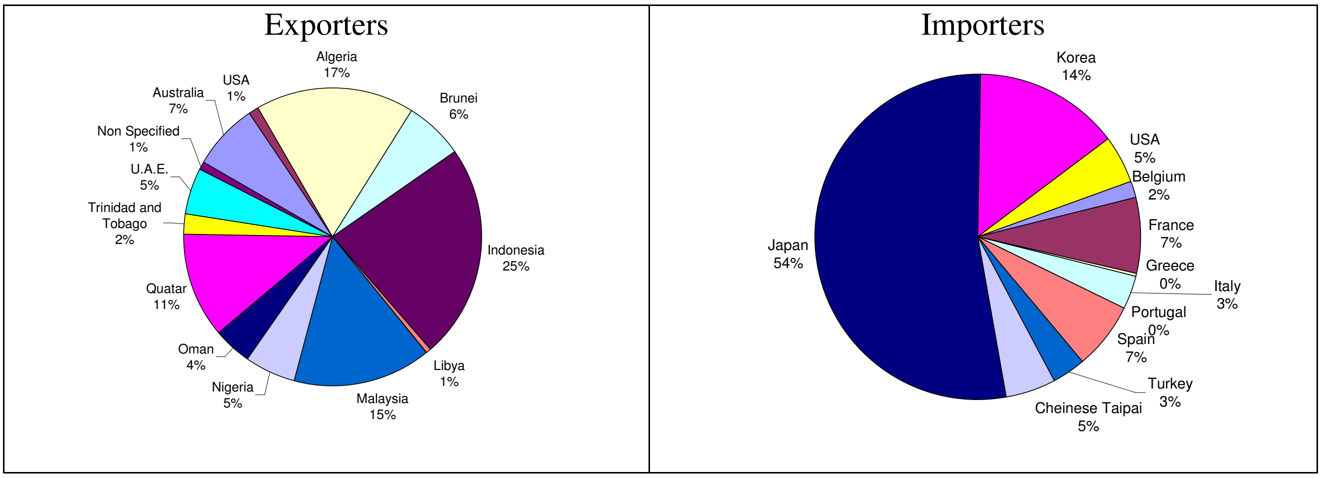


The future EU gas demand can be met by both pipelines and LNG import. The latest EU Commission proposal includes recommendations of 7 new LNG import terminals – see the subsequent chapters.

(b) LNG in Europe

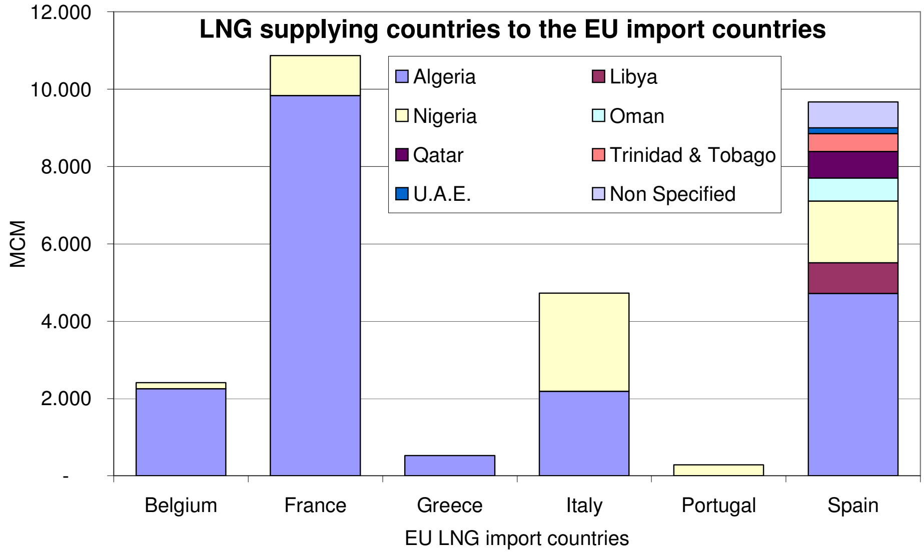
Of the 250 Bcm natural gas, which the individual EU member countries imported in 2001, around 28.5 Bcm were LNG – more than 11%.

Figure World LNG Exporters and Importers 2001[87]



The main World LNG suppliers today are Indonesia 25%, Algeria 17%, Malaysia 15% and Qatar 11%. However, when looking at LNG import to EU the picture is different, as Algeria stands for 70%, Nigeria for 20% while Oman, Qatar, Trinidad and Tobago, and U.A.E. together stand for around 10%.

Figure EU LNG importers and supplying countries 2001



[87] IEA, Natural Gas Information 2002

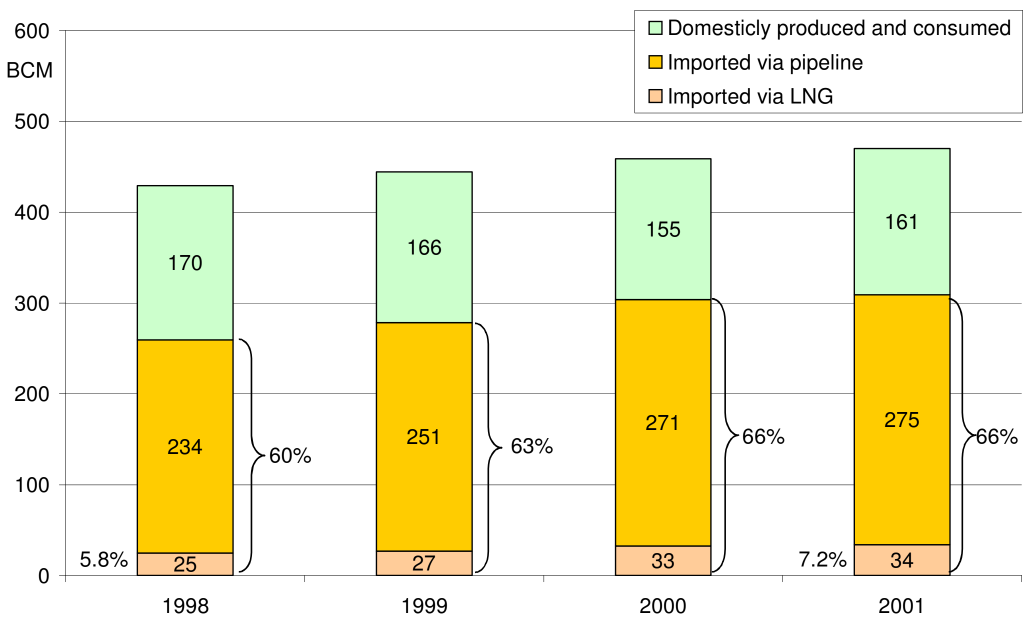
The largest LNG importers are Japan 54%, Korea 14%, and France and Spain that stand for 7% each. EU consumes 20% of the world's LNG import. Whereas France and the other EU LNG importing countries only receive LNG from two countries or less, Spain is receiving LNG from seven countries: Algeria, Libya, Nigeria, Oman, Qatar, Trinidad and Tobago, and U.A.E.

(c) LNG imports are increasingly important for the EU

LNG imports are mainly considered when distances from the supplying country exceeds around 2000 km for an offshore connection, or more than 4000 km for an onshore connection. However, strengthening of the European gas system in its geographic areas in the periphery of the continent is based on LNG import options or support from increased gas storages. Currently, five EU countries have LNG import terminals: Spain (3), France (2), Belgium (1), Greece (1) and Italy (1).

LNG supplies for Europe have been increasing in size with a value of 0.5% per year of the total gas consumption in Europe or around 2.5 bcm yearly.

Figure LNG share in European gas trade



In general, North African gas and LNG are competing for shares in a rapidly evolving Mediterranean power sector market, as well as in the overall EU gas supply policies. This emphasises the great importance in Europe of the gas sector in Northern Africa (and Middle East).

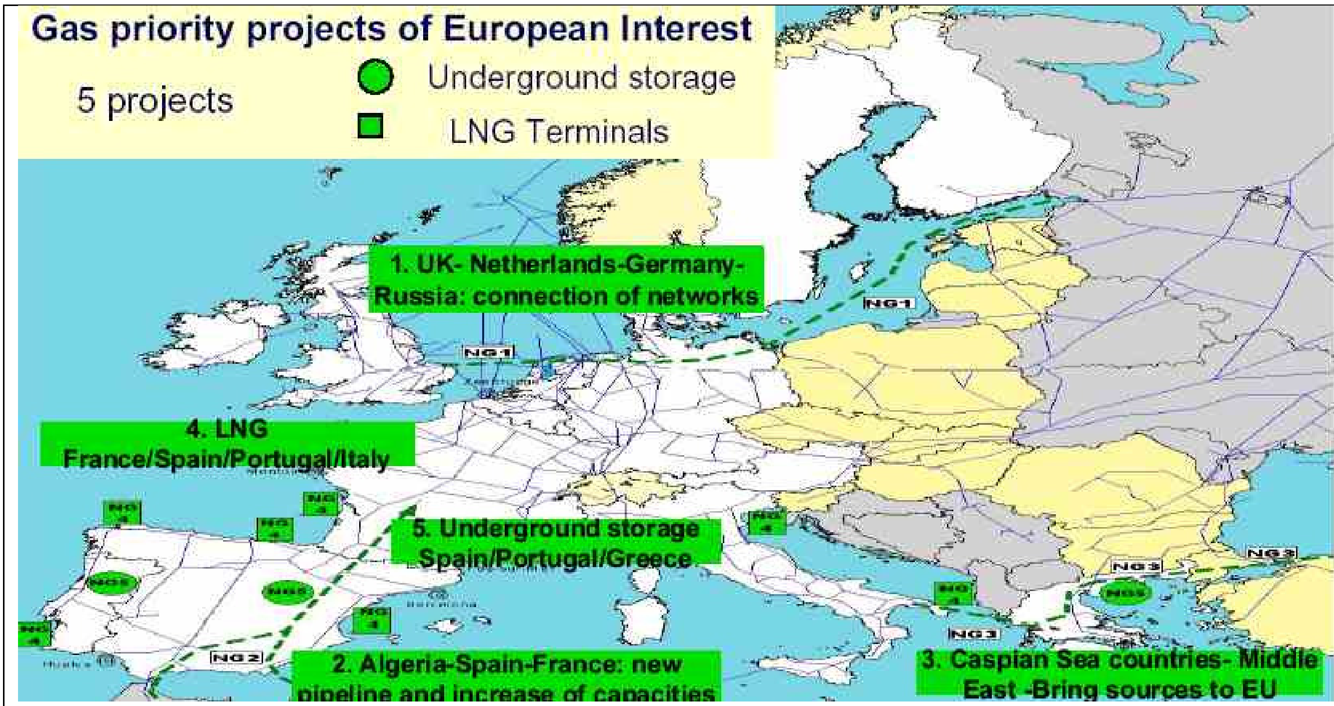
(d) Number of LNG terminals is to double before 2020

The most recent EU Commission proposal on "Guidelines for trans-European energy networks" includes 13 priority infrastructure projects of European interest. The proposed priority projects fall in three groups: (1) New large-scale import pipelines, (2) underground gas storages, and (3) Seven LNG import projects.

The large import pipelines fulfil EU policies of connecting the main sources of gas in Europe, improving the interoperability of the networks, and increasing the security of supply, as well as linking new sources to the European system.

The underground gas storages mainly focus on supporting the newly developed gas markets in the Mediterranean area with sufficient flexibility to meet the fluctuating demand and increasing the supply security in case of disruptions of the offshore import pipelines from Algeria and Morocco.

Figure LNG priority projects



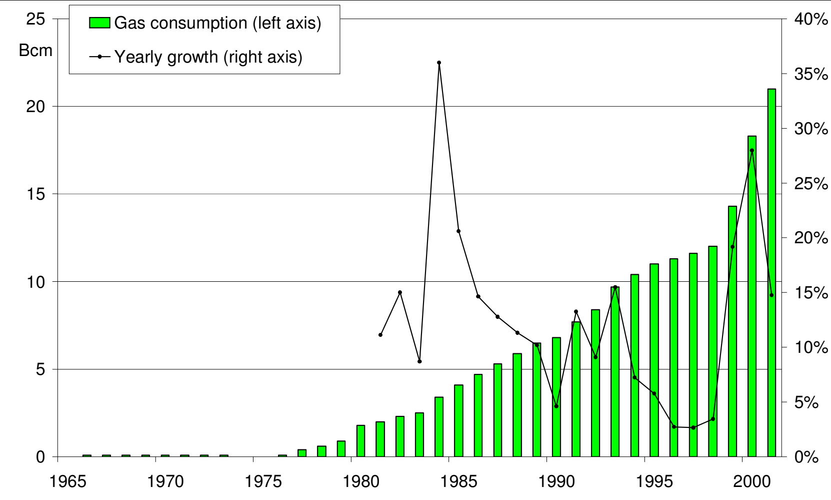
Seven LNG terminals are proposed in France, Spain, Portugal, and Italy. This will increase the number of entry-points in the geographic areas that have the longest distance from the supplying countries.

The previously mentioned growth in LNG import of 2.5 bcm yearly corresponds roughly to one small import terminal a year.

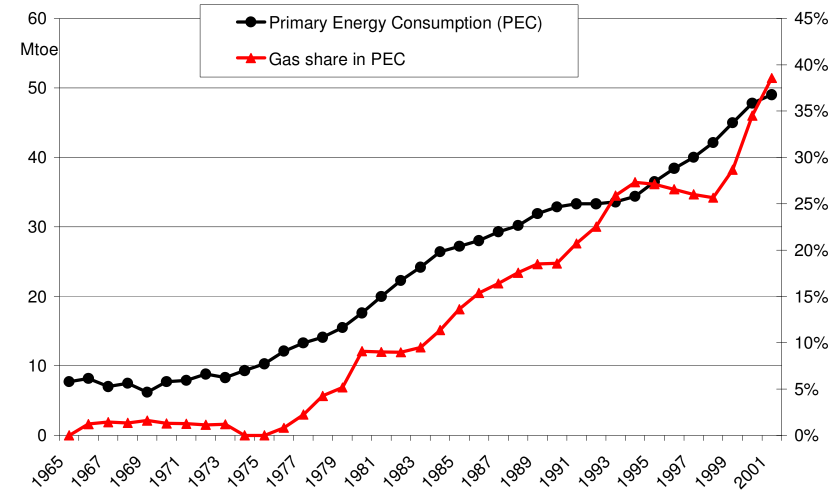
II. The Gas Sector in Egypt

1. Reserves, Production and Consumption

The Egyptian gas company EGAS presented a revised estimate of proven natural gas reserves in September 2001, with around 1560 bcm (55 Tcf), based on several new finds. Probable reserves are estimated to be around 3400 bcm (120 Tcf). Most of the recent increase comes as a result of new gas discoveries in the Mediterranean offshore/Nile Delta region, and some finds in the Western Desert. As a result, natural gas is likely to be the primary growth engine of Egypt's energy sector in the coming decades,eplacing the now constant oil production.



Historic development of natural gas consumption presents clearly the explosion in growth, which has been the case for the last 3 years with annual growth figures of more than 15%.



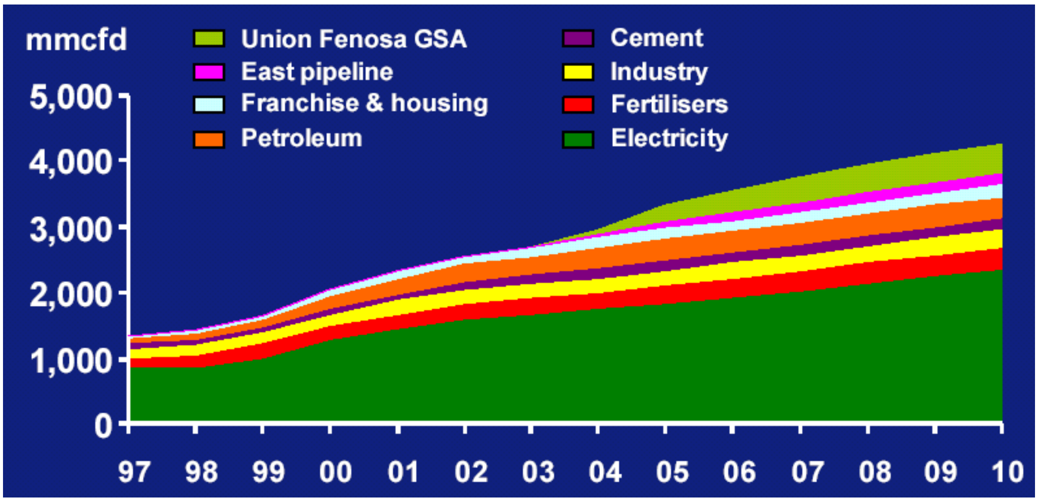
Historic development of PEC has for the last five year been higher than 5% pro anno.

Gas share in the PEC has reached of close to 45%. And will most likely within 3-4 years become the most common fuel in Egypt.

The rapid and large new discoveries have resulted in anexpected near doubling of the production between 1999 and 2002. Production stood at 16 bcm (1.6 Bcf/d) in the beginning of 1999, reaching 25 bcm (2.5 bcf/d) by 2001, and it is expected to increase further to 31 bcm (3.0 Bcf/d) by the end of 2002. The domestic consumption equals all the produced volume, making Egypt a supply-restricted gas market. The 25 bcm consumed is split with approximately 62% in the power sector, 28% in the large industries, 11% in the petroleum sector, and finally 3% in the residential sector and for CBG purposes. The main industrial segments are fertilizers and cement/ceramic – both having a 9%-point consumption.

Based on the current level of reserves (1560) and production (25), the Egyptian R/p ratio indicated the existing reserves during the last more than 60 years. Based on the larger resource estimate, it is prolonged to more than 136 years.

The Egyptian gas demand have been forecasted based on GASCO and British Gas assessments:



The annual growth is around 5% per annum for the period until 2010. Resulting in a 50% higher consumption than today.

The Egyptian key stakeholders in the wind-gas sector are:

- MEE – Ministry of Electricity and Energy
- MOP – Ministry of Petroleum
- EEHC – Egyptian Electricity Holding Company
- EGAS – Egyptian Gas Company
- GASCO – Egyptian Gas Transmission Company

<u>2. Current export development plans and projects</u>

In 1999, the Egyptian government stated that natural gas reserves were more than sufficient for domestic needs, and that foreign firms producing gas in Egypt should seek export options. These are investigating in collaboration with EGAS as the domestic company responsible for development of the Egyptian natural gas activities, and as co-ordinator and potential partner in all projects.

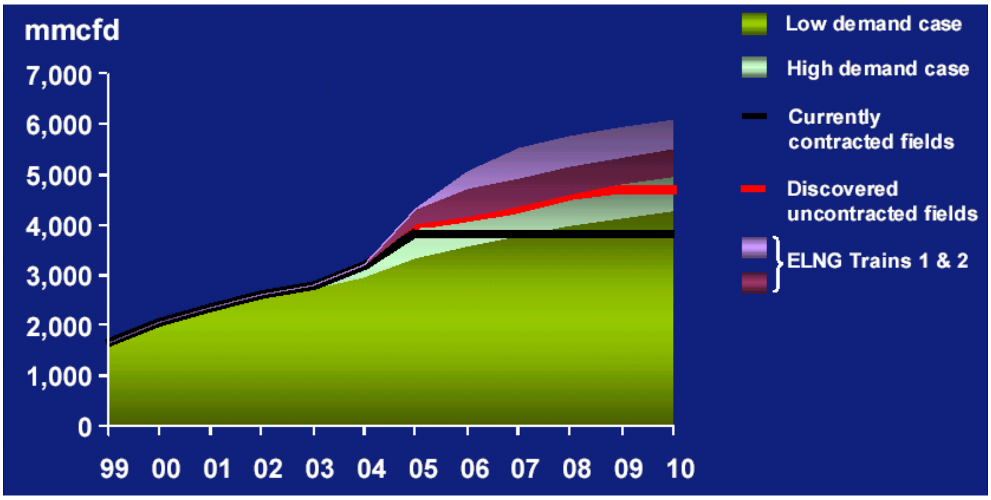
- **Export pipeline to Jordan (Orient Gas Pipeline)**
  Currently a first export pipeline to Jordan is under construction, and set for completion around March-July 2003. The project is estimated at 200 MUSD, of which the Arab Fund for Economic and Social Development has granted Egypt a 55 MUSD soft loan, while Kuwait Fund for Development contributes with 108 MUSD. Egypt has commissioned the

construction of the section from the existing pipeline El-Arish to Taba in Sinai. The final subsea section in the Gulf of Aqaba bypassing Israeli waters to Jordan is currently being prepared. The Jordanian gas company is evaluating offers for the construction of the section Jordan section connecting the more populous centres of northern Jordan. Egypt, Jordan, and Syria agreed in principle in early 2001 to extend the pipeline into Syria, with possible natural gas exports to Turkey and Lebanon. The feasibility of this option is however questionable, since Turkish demand would probably not support another source of piped gas (beyond agreements in place with Russia, Azerbaijan, and Iran).

- **Export pipeline to Israel**
  An offshore pipeline from El-Arish in Sinai up the coast of Israel, with a possible extension onward to Turkey, has been assessed. However, the current status in Egyptian-Israeli relations has made further assessments less likely. The promoters of the project was East Mediterranean Gas Company (a consortium of EGPC, Merhav of Israel, and Egyptian businessman Hussein Salem). ENI already started on the construction of a pipeline along Egypt's Mediterranean coast to El-Arish, which could have been a natural starting point for the export project.

There are currently 2-3 actual LNG projects in line, but more are under discussion/planning:

- **LNG project 1+2 (Britsh Gas – BG and Edison)**
  The BG project for export of LNG is termed “Egyptian LNG” or simply ELNG. The project should be considered as a part of the overall BG exploration and production in Egypt. First step was operation from the Rosetta gas field (Q1, 2001). Next step is development of the Scarab Saffron gas field, which is expected to be operational in during third quarter in 2003. Subsequently, the Simian Sienna gas field should be developed during 2004-2005. The ELNG is divided into two parts – LNG trains. The first train is planned to com in operation during mid-2005, exporting gas from the Simian Sienna field. The second train should export from mid-2006 from other VDDM fields. An LNG Export Project Agreement was signed in April 2001, defining the principles for the plant location including use of a tax free zone. The People’s Assembly endorsed the contract March in 2002. A Heads of Terms was signed with Gaz de France (GdF) in January 2002, giving GdF the right to purchase the full output from ELNG Train 1 for 20 years, as well as a 5% ownership in the company. The ELNG Train 1 is estimated to cost around 900 MUSD. Ttechnically delivery is 3.6 mt/a per train. A second train is planned. Tendering on the debt financing of the project is ongoing during August and September 2002. Most likely, total financing (1.15 BUSD) will consist of 450 MUSD from EIB, 500-600 MUSD raised by international banks, and 100-200 MUSD from Egyptian banks.



- **LNG project 3+4 (Fenosa)**
  Union Fenosa signed a firm contract with EGPC in July 2000 for the purchase of natural gas for an LNG gasification terminal, which is to be completed by mid-2004 at Damietta on the Nile Delta coast. However no specific gas reserves are currently allocated to the project. Union Fenosa has started awarding contracts for design services, and some long lead time items have already been awarded. Project capacity is 141 Bcf-per-year. Most of the gas will be used at Union Fenosa power plants in Spain, with additional volumes being sold to other customers in Spain and elsewhere in Europe. The project has not yet invited banks for debt financing. International banks have commented that the project would be more attractive, if Union Fenosa manages to bring a strategic partner into the development. Preferably a large international oil or gas company with references on constructing and running an LNG project.

- **LNG project 5 (El Paso)**
  American El Paso Global LNG signed in April 2002 a Memorandum of Understanding (MOU) with the Egyptian Natural Gas Holding Company (EGAS) and the Egyptian General Petroleum Corporation (EGPC) with the aim of investigating opportunities for El Paso to invest in the natural gas sector in Egypt. The MOU allows the parties to co-operate in the exploration, production, gathering, transportation and processing of natural gas and the possible development of a liquefied natural gas (LNG) liquefaction plant in Egypt. The parties will begin various studies of Egypt's natural gas sector immediately. El Paso has taken potential supply from Egypt into their planning for the US market. In their latest Quarterly Report they estimated that LNG could be delivered for around 3.5 USD/MBtu Qatar and Egypt. Based on the fact that Egypt is closer to the US than any supplier from south-east Asia, anddue to the fact that there are several companies in Egypt with considerable LNG experience including BG and BP.

- **LNG projects 6 (BP) and 7 (Shell)**
  BP Amoco has signed a letter of intent with EGPC for a two-train LNG terminal to be completed by 2004. The project would include a facility to produce liquefied petroleum gas (LPG), of which Egypt currently imports a large share of its consumption.

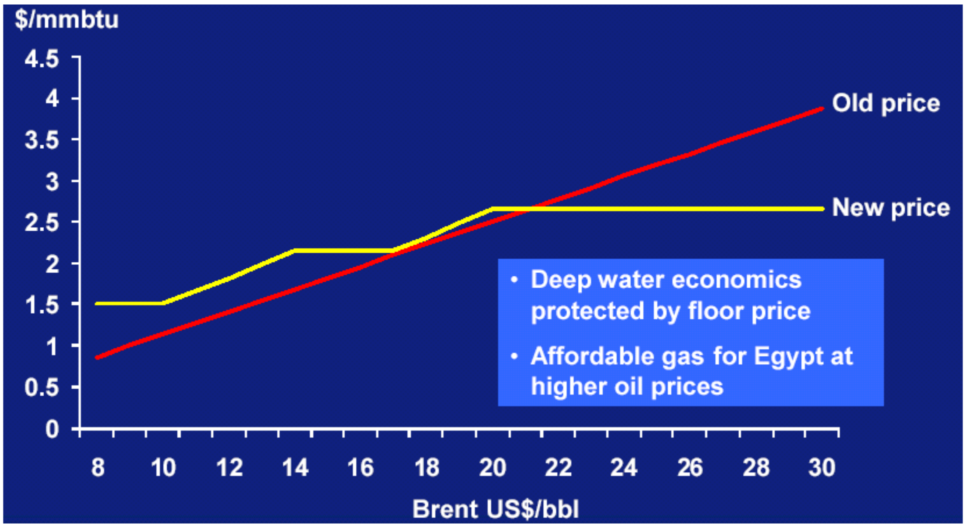
  Shell has proposed projects involving both an LNG export terminal and a facility for 75,000 bbl/d gas-to-liquids production of petroleum products for the growing local market.

3. Gas tariffs and costs in Egypt

Gas tariffs in Egypt are unique in the sense of stability. The gas (and electricity) tariffs were set in 1992 and have been unchanged since. However, a relatively high inflation has in fact decreased the prices in real terms. The tariffs set in EGP are as follows:

Consumer segment	Tariff, EGP/m³	Tariff, USD/MBtu
Industries and power plants	0.141	0.9
Foreign investors		2.2
CNG for transport	0.450	2.7
Household		
- Cons. < 20 m³	0.100	0.6
- 20 m³ < Cons. < 30 m³	0.200	1.2
- Cons. > 30 m³	0.600	1.8

Below is shown the EGAS PSA contracts dependence on the international oil price:



III. Forecast for Windfarm Productivity Index

PRODUCTIVITY DEVELOPMENT AS YEARLY INDEX			
Year for Investment in Windfarm	Investment/MW	MWH/MW	O&M/kWh
2002	1.00	1.00	1.00
2003	0.97	1.01	0.99
2004	0.93	1.02	0.97
2005	0.90	1.03	0.96
2006	0.87	1.04	0.94
2007	0.84	1.05	0.93
2008	0.81	1.06	0.91
2009	0.78	1.07	0.90
2010	0.75	1.08	0.89
2011	0.74	1.09	0.88
2012	0.72	1.09	0.87
2013	0.71	1.10	0.86
2014	0.69	1.10	0.85
2015	0.68	1.11	0.84
2016	0.67	1.12	0.83
2017	0.65	1.12	0.83
2018	0.64	1.13	0.82
2019	0.63	1.13	0.81
2020	0.61	1.14	0.80
2021	0.61	1.14	0.80
2022	0.60	1.14	0.79
2023	0.59	1.15	0.79

The index is based on forecasts by the author of this report.

Historic Productivity Increases Windenergy Technology

USA	1981	1985	1990	1996	1999	2001
Cost per kW	2600	1650	1333	1050	950	790
		0.63	0.81	0.79	0.90	0.83
		-10.7%	-4.2%	-3.9%	-3.3%	-8.8%
Denmark	1981	1995	2000			
Uscents per kWh	16.9	6.15	4.92			
		0.36	0.80			
		-7.0%	-4.4%			

IV. Forecast for future CCGT Cost of Production

1. Productivity Assumption

The report uses the following assumptions for productivity development in future CCGTs.

Expected Future Productivity Increases in CCGT	2004-2014	2014-2024	
Annual Decline in Cost of Investment in new CCGT Plant	0%	1.0%	
Energy Efficiency of new CCGT Plants installed 2010, 2015, 2020	61%	62%	63%

2. Justification

The theoretical and actual productivity increases vary when the topic is gas-fired power plants. The European Commission presented in 1996 their publication "European Energy to 2020", where the development of power plant efficiencies had separate presentation. The EU report expected that the theoretical cycle efficiency would be around 73%, indicating that today's technology (with 57%) reaches just under 80% of the theoretical maximum. The report expected that power efficiencies in combined cycle turbines would reach 60% before year 2000, followed by a smaller increase until 2015-2020, where the level would be around 62%.

However, the actual development has halted the development at around 55-57%, which is the efficiency of the newest power plants in UK and Japan. Both Japan and Norway have plans for constructing power plants based on a 58-62% efficiency, both still it is plans.

Efforts to improve combined cycle power plant efficiency concentrate on development of new materials and alloys and innovations in turbine blade cooling which allows gas turbines to tolerate higher temperatures. Operating at higher gas turbine inlet temperatures closer to the theoretical maximum results in increasing the turbine specific work and consequently improving the cycle thermodynamic efficiency (the theoretical maximum is in the order of 73 %). Consequently reducing fuel consumption which has a good contribution to the plant operating costs. The maximum cycle temperature has increased from 1300-1400 ^{o}C for F class turbines (with CCPP efficiency in the range 55-57 %) to 1500 ^{o}C in the G and H classes (CCPP efficiencies of 58 and 60 %) and is expected to go through a plateau due to environmental considerations related to NOX formation. Therefore, it is expected that the new H class turbines will play a major role for high efficiency power generation in the next decade. The cost of this efficiency improvements is expected to balance the decrease in plant prices over the years thus resulting in a more or less constant plant price.

A single percentage point of efficiency gained can reduce operating costs by $15 million to $20 million over the life of a typical, gas-fired combined-cycle plant rated at 400 to 500 MW, according to an original equipment manufacturer quoted in Gas Turbine World's 2000-2001 handbook.

The cost of electricity generation using combined cycle gas turbine plants is sensitive to gas prices and is in the order of 0.035 $/kWh internationally on both sides of the Atlantic. However, due to the current low cost of Gas in Egypt (0.88 $/Mbtu), the average cost of generation is in the order of

0.025 $/kWh. However, the low gas prices due to the devaluation of the Local currency are expected to increase in the future and recover its real value.

Figure 1 shows average turnkey prices for combined cycle power plants of different installed capacities. The comparison shows that the prices in 1996 have dropped by 6 to 22 % in 1998 then remained almost steady in 2000 (as indicated from the statistics of the world gas turbine handbook). This was probably due to fluctuation of foreign currencies against the US $.

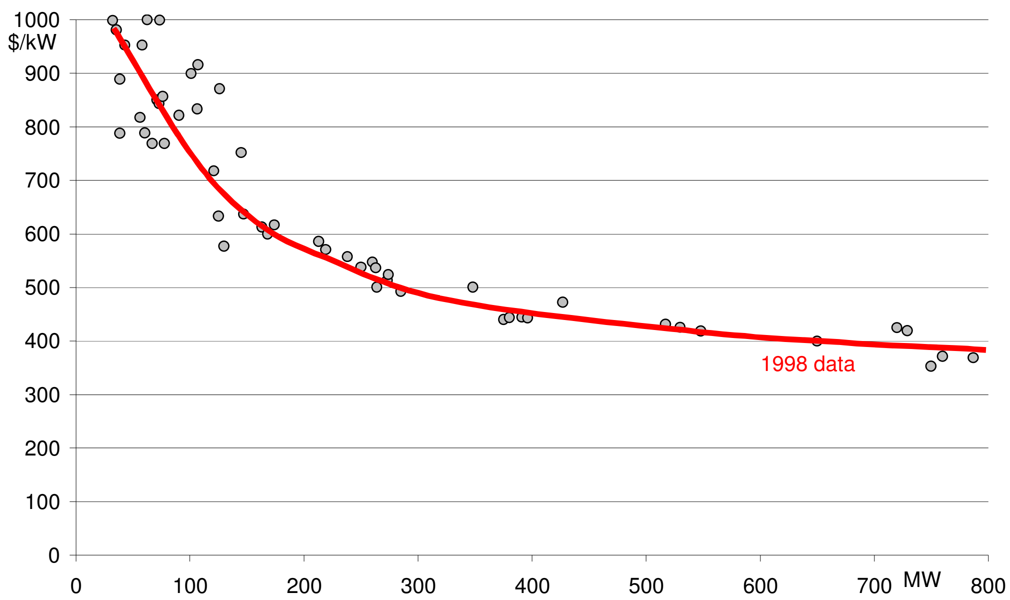
Table (1) illustrates a breakdown of the costs in combined cycle power plants for different Gas prices and using 10% for depreciation and 75% capacity factor.

Table (1) Breakdown of the costs in combined cycle power plants

Case	**NG price ($/Mbtu)**	**Capital Cost ($/kW)**	**Interest+ depr. (C/kWh)**	**Fuel cost (C/kWh)**	**Non-fuel O&M (C/kWh)**	**Total cost (C/kWh)**
1	1.5	500	0.76	1.02	0.48	2.26* (2.1)**
2	2.5	500	0.76	1.71	0.48	2.95 (2.7)
3	4.0	500	0.76	2.73	0.48	3.97 (3.5)

* Production costs based on **50 %** CCPP efficiency
** Production cost in brackets is based on **60 %** CCPP efficiency

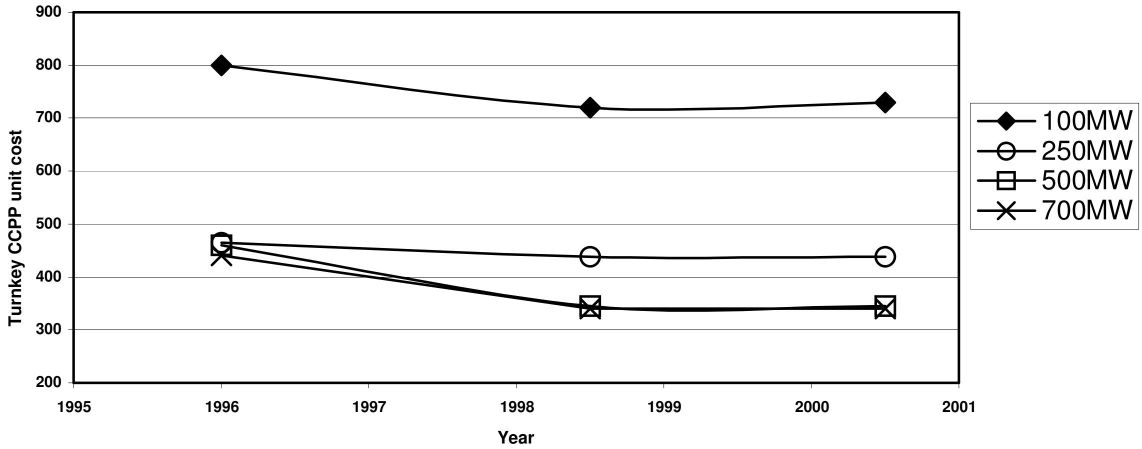
Based on actual standardised turn-key contracts for the year 1998, the following graph presents the investment costs for new combined cycle gas turbines[88].



The unit costs decreases largely from small 100 MW turbines at 750 USD/kW, down to 250 MW

[88] Data from 1999 Gas Turbine World Handbook.

Figure (1) Development of Average Turnkey CCPP Budget prices ($/kW) (World GT Handbook)



The H Class Turbine:

The General Electric H turbine system taking shape in Wales is making a bid for a new record in thermal efficiency. This summer, on an aging industrial site in South Wales, a breakthrough in energy efficiency may take place, when the first General Electric Power Systems H turbine system begins operating. The H turbine is designed to be 60 percent thermally efficient, long considered the four-minute mile of power generation. The Welsh installation will serve as a springboard for two other installations, planned for New York State and Tokyo, so that the technology will span three continents.

The 480-megawatt H system in Wales is designed to be the first gas turbine combined-cycle system in the world to achieve 60 percent thermal efficiency. At the same time, it will produce fewer emissions than conventional combined-cycle plants. The main advantage provided by efficiency is economic, because fuel represents the largest single expense in running a fossil-fueled power plant. GE designed and built two models—a 60-Hz version called the 7H, and the 50-Hz 9H, which is the one being installed in Wales. They share similar designs and capabilities. Both derive their performances from their advanced materials and a new steam cooling system that enables the H gas turbines to operate at 2,600°F, or about 1,400°C, firing temperature, more than 200°F, or some 110°C, above previous-generation F technology gas turbines.

V. Forecast for future Market Prices for GHG-Reductions

The refusal of the USA to ratify the Kyoto-Protocol and US active opposition to the establishment of international trading schemes for GHG-certificates slows down the development of a well-functioning internal market for CO_2 certificates. And by withdrawing 50% of potential demand from Annex I countries for certificates, the action puts a tremendous downward pressure on the market price for certificates.

In the absence of a "true" international market place for certificates, the market is at present largely limited to the demand from public carbon-purchasing programmes. The prices that these are prepared to pay vary currently between US$ 3 per ton of CO2 (PCF[89]) and US$ 9 (Dutch Government purchases from JIP in Poland).[90]

Yet, efforts continue in getting a proper functioning international CDM-market established. The question is: what prices can we expect?

- A World Bank financed report prepared for the EEAA and published in October 2002 gives an estimate of US$2.1 per ton CO_2. That is probably a realistic price estimate as long as the US-administration makes no efforts to actively support the international CDM-market.
- The IEA presents an average marginal CO2 abatement cost, including global trading, at around 8 USD per ton of CO2. [91] The results of the eight different models vary between 4-24 USD per ton of CO2.

To quote a recent report:[92]

(star"With respect to the CDM, there is price differentiation based on the perceived risks associated with different types of credits, with additional considerations given to the creditworthiness of the seller. Emission Reductions with a perceived high likelihood of acceptance under the CDM are selling at a premium – between € 3 and € 8 per tCO2e. Other verified credits that are perceived as less likely to meet either host government acceptance or other verification criteria are selling at a discount, in the range of € 1.75 to € 3.00 per tCO2e. Current PCF pricing is within a range of € 2.5-3.5/CER and The Netherlands CERUPT pricing is between €3.3-5.5/CER.

To date, the majority of credit sales have been *direct purchase* transactions, while somewhere between one quarter and one half of such trades are classified as *derivative purchases*. 'Derivative purchases' means the trading of sales on the secondary market, i.e. the re-sale of credits to third parties). Of significant interest is that the prices achieved in the marketplace are above those projected in the majority of climate change modelling. This is likely to reflect the emerging nature

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[89] The Prototype Carbon Fund's (PCF) current price objectives have been defined with screening criteria for eligible PCF projects of up to $10/tC or $3/t CO2. The existing carbon purchase agreements have an incremental cost less than $10/t/Carbon or $3-4/t CO2 averaged over the portfolio of projects.

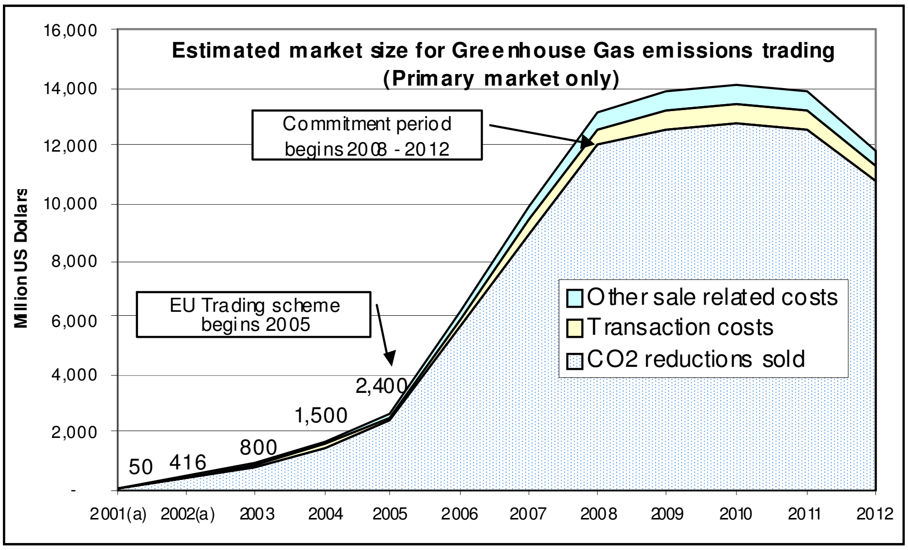
[90] Factors that have an impact on the carbon revenues include type of project, project location, project related negotiations, etc. Another important factor is the type of GHG, which is reduced. Methane reduction projects, such as landfill gas projects for electricity generation face better economic conditions.

[91] International Energy Agency "International Emission Trading – from concept to reality" (2001)

[92] EcoSecurities: *Analytical Assessment of the Business Situation for CDM Projects and Business Interests in the Netherlands"*. Paper prepared for Danish Energy Authority, March 2003.

of the market, with buyers willing to pay a premium for credits to achieve objectives apart from cost minimization, such as those with high social and environmental benefits.

An estimation of future market volumes until the end of the first commitment period under the Kyoto Protocol is provided in Figure 1. In the figure, historical data of the past two years are also included." (end of quote)



	2001(a)	2002(a)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Million tons of CO2e sold	25	104	200	300	400	700	900	1000	900	800	700	600
price per ton of CO2 (US$)	2	4	4	5	6	8	10	12	14	16	18	18

Figure 1 - Estimated market size for GHG emission trading (primary market only). Source: *The Carbon Market Analyst – News Alert 28 February 2002*; other figures are EcoSecurities analysis

It is reasonable to conclude that the international price for CO2-certificates during the next ten years will be in the range of US$2-8 per ton CO_2, and that it is likely to be closer to the lower end of the range than to the upper.

This report has chosen to use a price of US$4 per ton CO_2 as its base case assumption; an optimistic, yet still realistic assumption.

V. Long-Term Tendency in the International Price of Oil

The long-term price movements on the international market for crude oil have been analysed by The Petroleum Finance Company in the report "World Petroleum Markets. A Framework for reliable Petroleum Projections", published as World Bank Technical Papers 92, Industry and Energy Series, 1988.

The report made two key observations on the behaviour of real crude oil prices since 1870:

1. The trend of the long run average of real crude oil prices has followed a constant price level.

2. Price cycles are an integral aspect of petroleum economics. Real crude oil prices have systematically risen above the relatively stable long-term average, only to then fall (often rapidly and dramatically) below this average.

The two charts shown overleaf, trace the trend in the real price of crude oil between 1870 and the mid-1980s. One will note that the long-term average price expressed in 1985-prices has been around US$10 per barrel. This corresponds to about US$21 expressed in year 2003 prices, the base case assumption used in this report.

Figure 9 (continued)
Real Crude Oil Prices
(1870-1970)

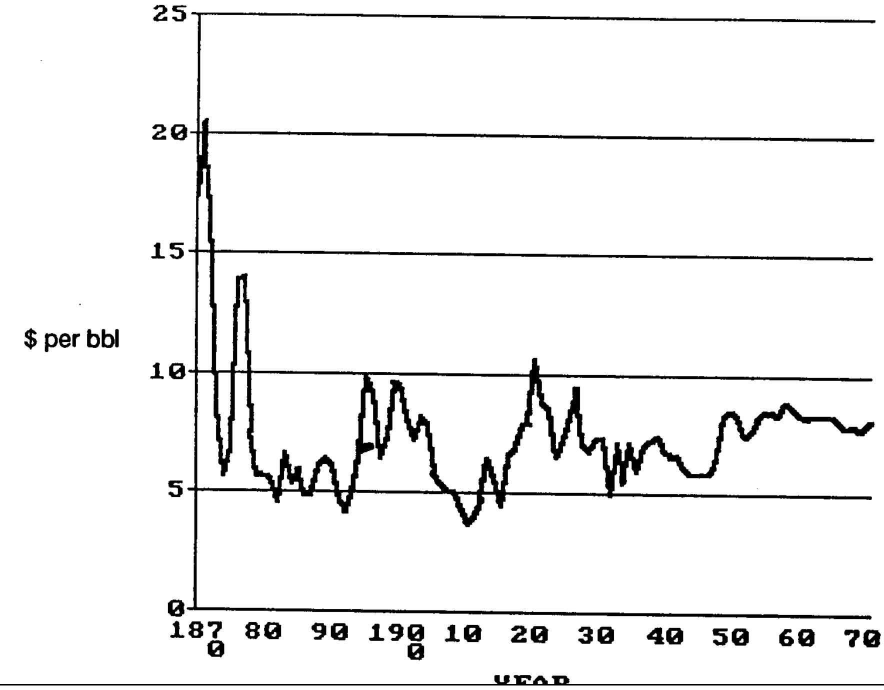


Figure 9 (continued)
Real and Nominal Crude Prices
(1970-1986)