The Portfolio Value of the Price Certainty offered by Windenergy

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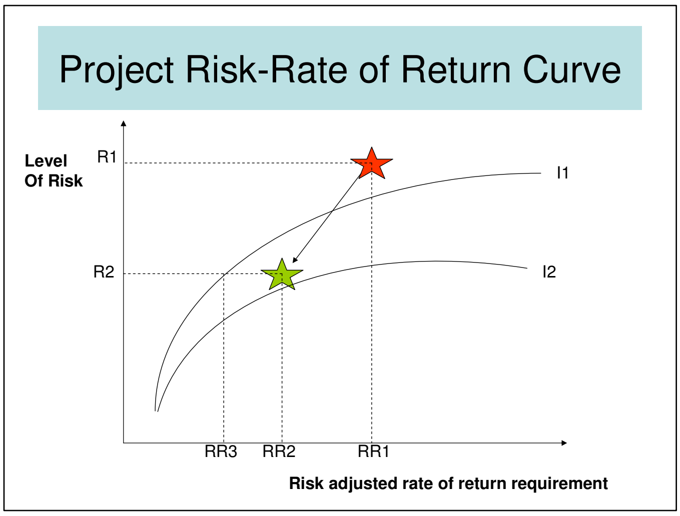
1. The theory

Policy makers in fuel-importing countries have always been concerned about the impact of rising international fuel prices on inflation rates, consumer purchasing power, balance of payments, GDP growth and employment. But during the regulated monopoly-utility days, power companies paid little attention to the consequences of price fluctuations as such because they would normally be allowed to pass them on to consumers. In response to the market uncertainties introduced by the liberalization of the power sector and the free competition on the bulk and retail markets, utilities have adjusted their planning methodology, making use of portfolio analysis when they draw up a least-cost power supply plan. In this, utilities try to get a mix of generation with different risk/rate-of-return profiles.

The *portfolio value of RE* refers to the value of protection against fuel price fluctuations offered by the long-term fixed prices of PPAs signed with RE generators. Fluctuating fuel prices impose adjustment costs on agents in the power system and on society; while long-term shifts in fossil fuel prices change the ranking of generators in the merit order for scheduling permanently. This creates uncertainty into the system, and economic agents are normally willing to pay a price for reducing uncertainty. A project developer or a lender reacts to project risks and uncertainty by either (i) staying away from undertaking the activity, or (ii) adjusting his risk-free rate of return upwards as compensation for accepting the risk and/or (iii) taking insurance against the risk. The "*project risk-rate of return" indifference curve (RR-line)* shows how a project developer's asked for rates of return on equity (or a lender's rate of interest) vary according to the perceived levels of project risks and uncertainties. Higher risks are accepted if compensated for by higher potential returns. Risk aversion leads the agent to ask for increasingly higher increments in the rate of return as projects move into incrementally higher risk areas until the agent's upper limit for accepted risk is reached. Projects located on or below the RR line (green project) are accepted by the agent with RR-line 1, projects above the line (red project) are rejected: corporate *risk-tolerance limits* cannot be exceeded.



Let us assume that a project developer asks a bank for a loan offering to pay the rate of interest RR1. Due to the project's risk level of R1, the bank is not interested. Let us the assume that use of hedging instruments shifts the project risk for the bank from the red to the green position. The fee RR1-RR2, which the bank pays the seller of the risk instrument to take over a specific risk, reduces the net interest rate for the bank from RR1 to RR2; yet, because the risk is reduced to R2, the bank is now willing to lend to the project.

Commercial risk instruments owe their existence to three factors:

- *Agents have different levels of risk aversion*: I2 in the chart could represent a commercial bank, I1 a development bank: the latter would finance the green project, the former not.
- *Portfolio investors* invest in assets with different RR-profiles, some high risk/high RR, some low risk/low RR. Adding a high risk/high RR asset, is profit-maximising strategy as long as the total risk-RR profile of the portfolio is not pushed beyond the RR-line frontier.

- Risk specialists, such as insurance companies or hedgers, can *price risks,* and thereby *changing what for a project developer is a project stopping uncertainty, into a quantified risk.*

Adding new risk management (hedging) instruments to the financial market *enables otherwise unwilling local project developers and financial intermediaries to engage in the development and financing of RE-projects* or to *provide funds with longer maturities* to RE-projects.[1]

The transfer of risks to specialists comes with a price tag for the lending institutions and/or project developers, which is part of the cost of capital. But since specialists are more efficient at managing specific risks than the entity transferring it, and risk transfers take place at the margin, where a reduction in risk leads to a relatively large reduction in the asked for rate of return, the *cost of capital in a free and efficient capital market will go down or, as a minimum be unchanged.* Otherwise, risk management instruments would not be on the market. This outcome is shown in the chart, where the hedging transaction brings the RR-profile of the project below the lender's RR-curve; meaning that the cost of capital to the project is reduced by the transaction. At the risk R2, the bank's minimum net rate of interest requirement is RR3, enabling the project developer to get his loan at a rate of interest of RR1 minus the difference between RR2 and RR3.

Given today's dynamic and uncertain environment in the energy sectors it is impossible to correctly identify the 30-year "least cost" option. Yet, traditional methods for *least-cost* power planning do not quantify the price of fuel price uncertainty, including this cost as one component in the cost of production per kWh. Conventional project analysis for least-cost planning compares alternatives on *a plant to plant comparison* using a fixed forecast fuel price; with the sensitivity of results to the fuel price assumption being shown in a separate risk analysis. By omitting a cost component of conventional power, this approach has an inherent bias against renewable energy technology.

One alternative approach is to *use the market price of hedged fuel prices* as fuel price in the financial-economic modelling of levelised power plant prices. Bolinger/Wiser/Golove found that this approach increases the calculated cost of natural gas fired power plants by UScents 0.5/kWh. Their approach can be summarized as follows: "If consumers value long-term price stability, then – contrary to common practice – any comparison of the levelized cost of renewable to gas-fired generation should be based on a *hedged gas price* input, rather than an *uncertain gas price forecast*. Utilities and others conducting such analyses tend to rely primarily on uncertain long-term forecasts of spot natural gas prices, rather than on prices that can be locked in through futures, swap, or fixed-price physical supply contracts (i.e., "forward prices"). The magnitude of the empirically derived premiums varies somewhat from year to year, contract, and by contract term, ranging from \$0.5-\$0.8/MMBtu, or 0.4-0.6¢/kWh assuming highly-efficient gas-fired power plant. This difference is striking, and implies that comparisons between renewable and gas-fired generation based on these forecasts over this period have arguably yielded results that are biased in favor of gas-fired generation. Source: Mark Bolinger, Ryan Wiser, and William Golove: "[2]

Another is to *apply the Capital Asset Pricing Model (CAPM)[3] from portfolio asset* theory to derive different discount factors for different levels of uncertainty. Using lower discount factors for uncertain fuel costs

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[1] In the chart the original stumbling block could have been that the bank was willing to provide a 6-year loan but not the 12-year loan, which the project developer needed

[2] Accounting for Fuel Price Risk When Comparing Renewable to Gas-Fired Generation: The Role of Forward Natural Gas Prices", Lawrence Berkeley National Laboratory, January 2004. Download from: http://eetd.lbl.gov/EA/EMP/

[3] Risk is defined in the traditional MPT sense as its cost *variability* from one time period to the next. The Capital Asset Pricing Model (CAPM) is a formula linking movements in a single share price to those of the market as a whole. The key statistic is "beta": the proportion of a given change in the market that, on average, is reflected in the price of the share. In modern portfolio theory, sometimes called mean-variance analysis, one analyzes the what extent the prices of the various assets in the portfolio move in unison. If the price of one product moves *opposite* to the other prices, then including it in the portfolio has a beneficial effect. If the size of that outweighs its higher present price, including it will improve the value of the portfolio.

increases the NPV of these and thus, the cost of production per kWh of plants using these fuels. The approach can be summarized as follows: "A portfolio of assets provides the best means of hedging possible future outcomes, to deal with uncertainty. Investors do not invest all their funds in a single stock on the basis of 30-year forecasts of stock performance. This is what traditional least-cost procedures imply. Giving the rapidly changing environment, it makes sense to shift energy policy from its current emphasis of evaluating alternative technologies, to evaluating alternative generating portfolios and strategies. Energy planning is an investment-decision problem and investors commonly apply portfolio theory to manage risk and maximize portfolio performance under a variety of unpredictable economic outcomes. Energy planning needs to focus less on trying to identify the "low-cost" generating alternative and more on developing efficient (optimal) generating portfolios that minimize cost at any given level of market risk. Conventional and renewable energy sources are best evaluated not on the basis of their *stand-alone* cost, but on the basis of their *portfolio cost*— their cost contribution relative to their risk contribution to a portfolio of generating assets. At any given time, some alternatives in the portfolio may have high costs while others have lower costs, yet over time, these relative costs may shift. The astute combination of alternatives serves to minimize overall generation cost relative to the risk."[4]

2. Examples of risks and their costs

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%.

The impact of a 4% increase in the interest rate, as seen in the table below, depends on the maturity of debt finance. In addition one cane distinguish between the increase in required tariffs during the amortization period, and the cost of production impact seen over the 25-year economic lifetime of a plant.

4% risk premium on the cost of capital and impact on the cost of generation per kWh

	Wind	**Geothermal**	**Hydropower**
	Uscent/kWh	Uscent/kWh	Uscent/kWh
10-Year loan			
- cost first 10 years	0.49	0.49	0.75
- lifetime cost increase	0.25	0.25	0.39
15-Year loan			
- cost first 15 years	0.50	0.50	0.77
- lifetime cost increase	0.36	0.36	0.55

Another impact of risk – and of an immature capital market - is to reduce the length of maturity of project loans. The table below shows that a reduction of maturity from 15 years to 10 years, adds 0.7 UScents to the cost-coverage tariff of a geothermal power plant and windfarm and 1 UScent to the tariff of a hydropower plant.

[4] See S. Awerbuch and M Berger, "Energy Diversity and Security in the EU: A Mean-Variance Portfolio Analysis," *IEA*, March 2003.

Length of Maturity and Impact on the Cost of Generation per kWh

Loan: 70% of investment	Geothermal Plant US$2 M/MW Capacity factor 80%	Hydropower Plant US$2.5 M/MW Capacity factor 65%	Windfarm US$1 M/MW Capacity factor 40%
15 year loan at 10% interest	1.8 UScents/kWh	2.8 UScents/kWh	1.8 Uscents/kWh
10 year loan at 10% interest	2.5 UScents/kWh	3.8 UScents/kWh	2.5 UScents/kWh

Thus, a perceived high-risk environment can easily increase the required tariff for a windfarm by 1.2 UScents per kWh through the combined effects of lower maturities and higher risk premiums on loan capital.

<u>Regulatory risk: impact on project finance</u>

Regulatory risk increases the *cost of capital* and decreases the likelihood that banks will undertake *non-recourse project finance*.[5]

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.

<u>Absence of hedging instruments for foreign exchange risk</u>

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.

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.

<u>Tariff policy for windfarm PPAs</u>

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

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

investors to the sector. In Spain, for example, the annual adjustments of Spain's two subsidy mechanisms[6] are the major reason for the "high-risk" rating of BBB- to BB+ by market analysts Standard and Poor (S&P).[7]

3. Portfolio value of wind energy in a gas-exporting country with fixed price regime

The portfolio value of windenergy may seem doubtful and academic in Egypt for two reasons:

1. Egypt is a fuel exporter, not a fuel importer. Egypt applies a tariff regime, which decouples the price of domestic natural gas from the price movements of LNG on the international market: producers of natural gas are paid in US$ per MBTU, that is, without reference to the international price of LNG. The pricing regime on the domestic energy and power market eliminates the fluctuations in gas prices by keeping prices charged to power plants constant in the short to medium term until inflation and devaluation leads to such large underpricing that it forces an upwards revision of the gas tariff. This type of price stability is an example of suppressed inflation. because the cost of subsidizing the financial losses becomes too high.

2. Because Egypt is a fuel exporter, not a fuel importer, it is not exposed to negative macro-economic chocks caused by rising costs of fuel imports. The macro-economic impact of rising fuel prices over time is positive for Egypt: export and tax income increases. The risk of changes in the international price of crude oil and, associated with it of LNG, is a risk of foregone export revenue.

The above points to two "risk-costs" of thermal power in the context of Egypt.

- The first are macro/micro-economic losses from misallocation of financial and physical resources in the country due to suppressed inflation. Somebody must pay for the financial subsidies to gas, whether it is the Government budget or EEHC's investment budget; in either case, the subsidy payments crowd out higher-value alternative investments.
- The second is the risk of economic losses from foregone export revenue because Egypt invested in too little renewable energy, since windenergy at the original price expectations for fuel seemed to be more expensive than power from gas turbines.

Thus, in Egypt, fuel price risks may be more hidden than in fuel importing countries, yet, they carry a price tag, which can be calculated with the help of analytical tools from CAPM (Capital Asset Pricing Model) - theory. The analysis has not yet been done. Therefore, a rough rule-of-thumb estimate must be used. International studies on the macro-economic impact of increasing oil prices on the world economy suggest that the *impact of an oil-price change is asymmetric*: the economic stimulus resulting from a fall in oil prices is significantly less intense than the depressive effect of a price increase.[8] One may conclude from this that the positive impact in Egypt of an oil-price increase is less than the negative impact in fuel-importing countries.[9]

For these reasons, this report sets the portfolio value of the long-term price certainty offered by PPAs with windfarms in Egypt at 50% of the cost of hedging natural gas prices in the USA (locking in the gas price through future contracts). Expressed in costs per kWh of gasfired power plants, gas price hedging in the USA

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[6] 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

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

[8] See IEA, Standing Group on Long-Term Cooperation: "The impact of higher oil prices on the world economy", 2003

[9] Another proof of that is that the boost to economic growth in oil-exporting countries provided by higher oil prices in the past has always been less than the loss of economic growth in importing countries, such that the net effect on average world economic growth has always been negative.

costs 0.5 UScents/kWh. This, report, thus estimates the portfolio value of windenergy in Egypt at 0.25 UScents/kWh = 1.5 piaster/kWh.

If CAPM-theory is applied in project analysis, one will not apply a single discount rate to all future costs and revenue streams, but a series of risk-weighted rates for the cost and revenue components. Differences in uncertainties and risks of alternative options for power supply are taking into account in comparative studies of costs of power production by *discounting future costs that are uncertain* at a lower *discount factor* than costs that can be predicted with higher degrees of certainty. When discounting benefits (revenues) the situation is the opposite: higher discount rates are applied to uncertain than to certain future revenues.

In the avoided cost analysis for the windfarm benefits, for example, the future annual costs of saved fuel would be discounted less heavily (increasing their NPV) than the capacity credit and the annual costs of non-fuel O&M. It is likely that application of CAPM-modelling to the power market in Egypt would result in a discount rate for the fuel component, which is 50% lower than the discount rate used for other components.

The illustrative purposes, the implication of applying a 5% discount rate for the cost of fuel and a 10% discount rate for all other costs for a year 2007 windfarm is shown in table 20.

Implications of CAPM Analysis for Portfolio Value of Windenergy

NPV of Avoided Costs	**10%**	**5%**
Fuel savings	264,142,916	383,030,887
O&M cost savings	4,843,714	
Capacity savings	82,932,152	
Nox savings - benefits	7,631,988	
TOTAL	359,550,770	478,438,741
NPV of MWh	2,237,365	
Avoided costs, piaster/kWh	16.1	21.4
Implicit Portfolio Value of Wind, piaster/kWh		5.3

If, the assumption of a 50% lower discount rate for fuel savings is realistic, then the portfolio value of windenergy is 5.3 *piaster/kWh*, and thus, much larger than the 1.5 piaster per kWh assumed in the economic calculations in this report.