"COMPUTER-BASED SIMULATION OF AUCTIONS OF OPTION CONTRACTS AND OF FUTURES CONTRACTS IN THE COLOMBIAN WHOLESALE ELECTRICITY MARKET"

Final Report – Chapter 5

Prepared for:

Comisión de Regulación de Energía y Gas (CREG)

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1. INTRODUCTION

In TERA's proposal, consumers (distributors, traders) are obliged to buy firm energy options but for producers selling options are not mandatory. In this chapter we analyze the attractiveness of the TERA's firm energy option proposal for generators in terms of profit maximization and risk hedging.

Two kinds of analyses are carried out. The first one is for the existing generators (hydro and thermal plants) and the second, for the new ones, to whom investment decisions have to be made. The latter point is important to evaluate to what extent firm energy options can contribute to generation expansion. Both types of analysis are based on the spot price and the generation scenarios computed in chapter two. The analysis is carried out with the program OPTFOLIO of PSRI for optimization of physical and financial assets in electricity markets.

Section 2 of this chapter presents estimates for the price of the energy options for different strike prices and risk premiums. Section 3 presents the analyses for the existing generators and Section 4 for the new ones. In Section 4 some conclusions are presented.

2. MARKET PRICE FOR ENERGY OPTION

The energy option in TERA's proposal has a performance period of five years and has to be acquired by consumers (distribution companies, traders, etc.) some time in advanced (eg. two years). It is composed by a strip of pure European style options, one for each time step and performance period. The total price of this strip can be estimated as the sum of the prices of each component. As this price is high it is suggested that it should be amortized from the time of acquisition until the beginning of the performance period.

In this analysis we consider monthly time steps with 5 load blocks, which are compatible with the price scenarios described in chapter 2 of this Final Report.

The period of analysis will start in January 2003. We will suppose that the first acquisition period will be from January 2003 to December 2004, and the first performance period, from January 2005 to December 2009. The second acquisition period will be from January 2008 to December 2009, and the second performance period, from January 2010 to December 2014 and so on. A total of five performance periods will be considered to cover a plant life time of 25 years, which starts to operate in January of 2005. Figure 2.1 shows the sequence of acquisition and performance periods.

As observed in chapter two, option prices will be based on their pay offs at the expiration date. As they have to be acquired in advance some discount rate has to be assumed. Two alternatives of yearly discount rates will be considered: 6%, which would correspond to the "risk free" discount rate; and 12%, which would correspond to a 5.6% premium over the "risk free" discount rate.

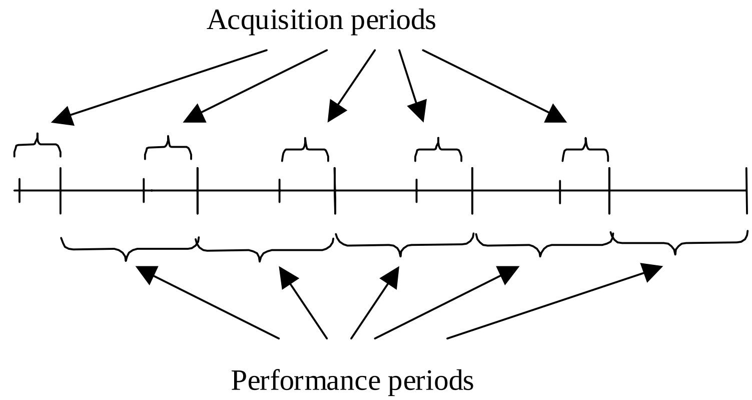


Figure 2.1 – Option Sequence

Five values for strike price are considered – US$ 30/MWh, US$ 50/MWh, US$ 100/MWh, US$ 150/MWh and US$ 200/MWh. For illustration, Figures 2.2 – 2.5 shows the monthly prices referred to the first month of the corresponding acquisition period, for the US$ 30/MWh and US$ 200/MWh strike prices and 6% and 12 % discount rates, for each component of the strip of European style option, and their mean over the corresponding performance period. Observe that as expected, once the strike price increases the option prices decrease, also as discount rate increases option prices decrease.

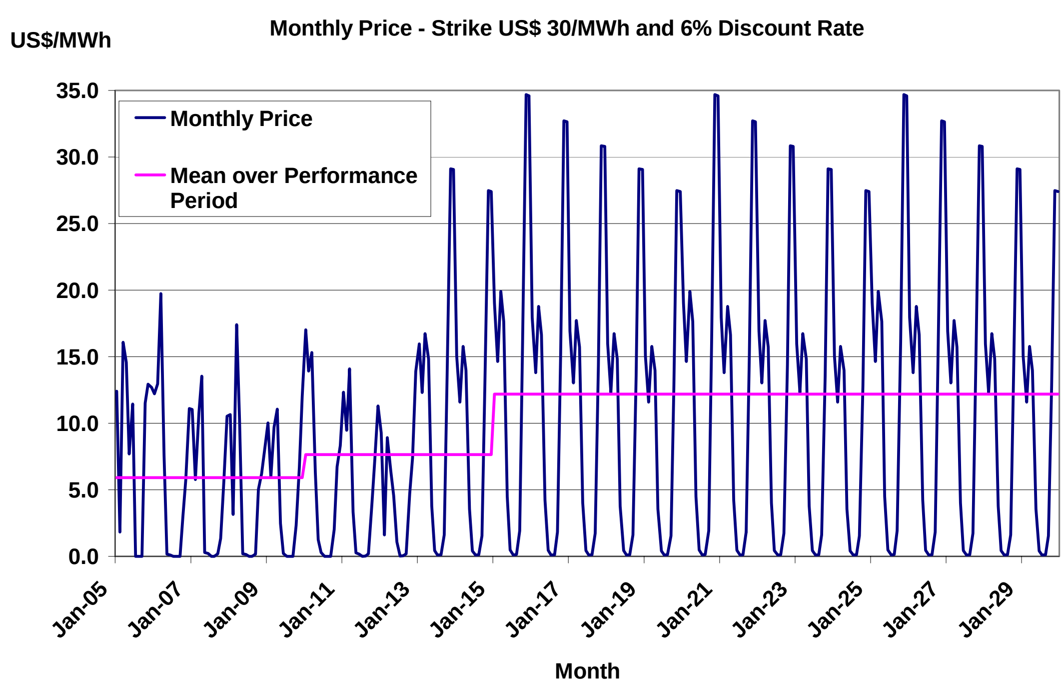


Figure 2.2 – Option Monthly Price – Strike US$30/MWh and 6% Discount Rate

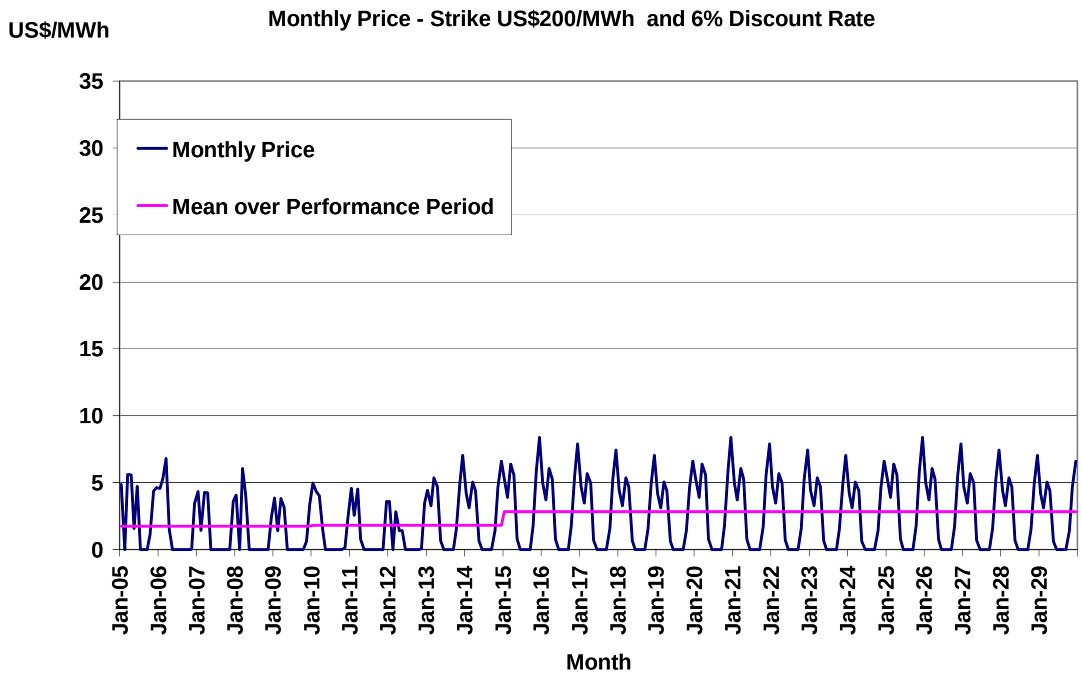


Figure 2.3 – Option Monthly Price – Strike US$200/MWh and 6% Discount Rate

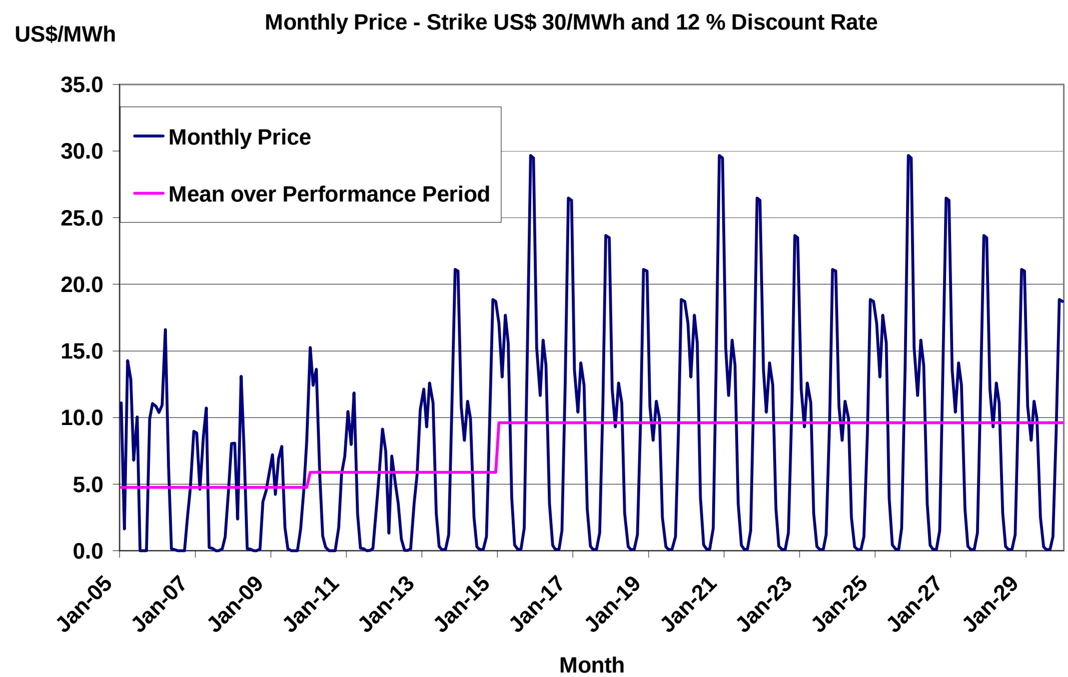


Figure 2.4 – Option Monthly Price – Strike US$30/MWh and 12% Discount Rate

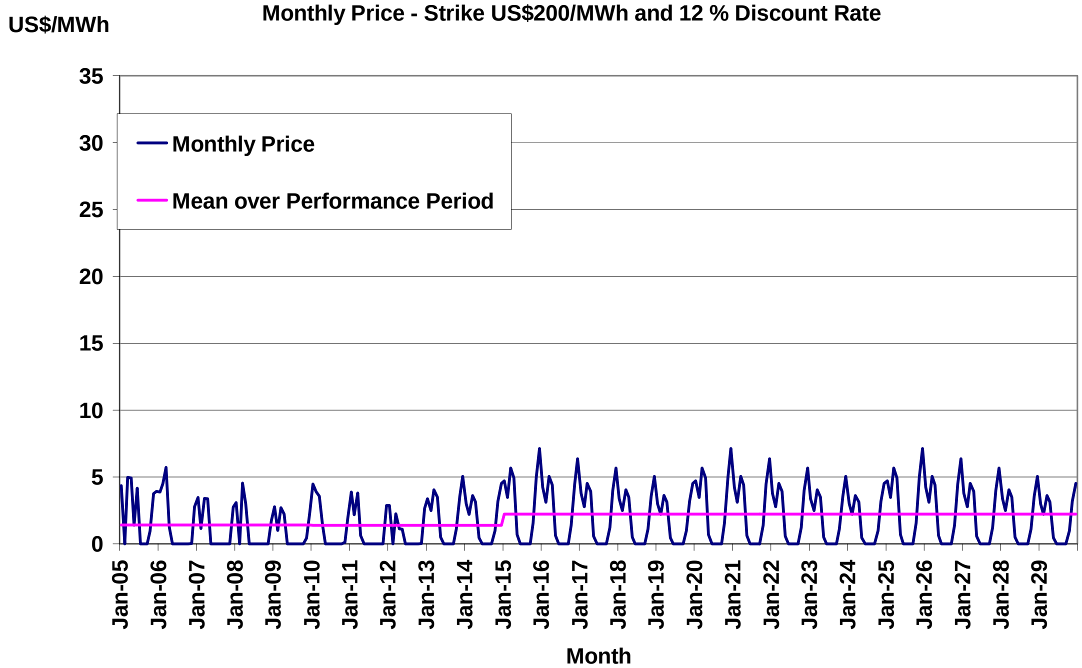


Figure 2.5 – Option Monthly Price – Strike US$200/MWh and 12% Discount rate

Consider now Figure 2.2, which shows that for the option with strike US$30/MWh the mean monthly price for the first performance period is US$ 5.92/MWh. Consider a plant with a maximum available capacity factor of 92%. Each 1kW of capacity would correspond to an energy of 0.92x8.760x5 = 40.30 MWh for the first performance period. Then total premium for the first performance period would be 5.92x40.30 = US$238.41. Considering that this premium will be amortized during the acquisition period (24 months), using a 6% annual interest rate, the monthly payment during this period would be equal to US$10.51 per kilowatt of capacity or US$10.51/kW[1]. Of course that if the plant has lower maximum available capacity factor then the premium will be lower. Also note that these monthly payments only occur during the acquisition period and not all the time as the current capacity payment. By a similar computation, option price per kilowatt of capacity is computed for the others performance periods, strike prices and discount rates For the 12 % discount rate cases it will be assumed that annual interest rate for option price amortization will also be 12%. Table 2.1 and 2.2 summarizes the results for this and the other strike prices, assuming a 6% and 12% discount rates, respectively.

[1] Option price is expressed in terms of US$/kW.month so that direct comparisons can be made between its value and the capacity payment amount established today in the Colombian market.

Strike (*)	Performance Period 1(**)	Performance Period 2(**)	Performance Period 3(**)	Performance Period 4(**)	Performance Period 5(**)
30	10.51	13.57	21.63	21.63	21.63
50	9.10	11.14	17.69	17.69	17.69
100	6.72	7.66	12.23	12.23	12.23
150	4.70	5.09	8.05	8.05	8.05
200	3.11	3.20	5.01	5.01	5.01

(*) US$/MWh

(**) US$ /kW.month

Table 2.1 – Monthly Payment in the Acquisition Period for the Corresponding Performance Period – 6% discount Rate (92% maximum available capacity factor)

Strike (*)	Performance Period 1(**)	Performance Period 2(**)	Performance Period 3(**)	Performance Period 4(**)	Performance Period 5(**)
30	8.84	10.96	17.91	17.91	17.91
50	7.67	9.00	14.66	14.66	14.66
100	5.68	6.19	10.15	10.15	10.15
150	3.98	4.13	6.68	6.68	6.68
200	2.64	2.60	4.17	4.17	4.17

(*) US$/MWh

(**) US$ /kW.month

Table 2.2 – Monthly Payment in the Acquisition Period for the Corresponding Performance Period – 12% discount Rate (92% maximum available capacity factor)

3. ANALYSIS FOR EXISTING PLANTS

In this section we analyze the attractiveness of the TERA'S firm energy option proposal for existing plants in terms of profit maximization and risk hedging. For illustration purposes, three plants of the Colombian system were chosen - two thermal plants (one combined cycle and one open cycle plant) and a hydro plant. Three alternatives for selling energy will be considered – direct to the spot market, bilateral contracts and firm energy options.

The criteria for optimization is to maximize plant discounted net revenue, at a discount rate of 12%, subjected to risk constraints. Risk constraints, when imposed, are expressed in terms of a minimum required amount that the yearly-accumulated net revenues must satisfy at a 95 % VaR level. This kind of risk constraints is more appropriate for dynamic risk hedging because a good result in a given year may not offset a bad result in another. Also, a constraint is imposed in the optimization so that the maximum amount of total contracting (bilateral contracts plus options) is less than or equal to the plant available capacity at each time period.

3.1. THERMAL PLANT – COMBINED CYCLE

The combined cycle plant chosen has 447.9 MW of nominal capacity and a mean available capacity of 358.3 MW. Its variable operating cost is US$ 11.9/MWh and it was assumed a fixed operating cost of US$ 2.00/kW.month.

The period of analysis is from January 2003 to December 2009.

In the first kind of evaluation we determine at which contract price it is better to sell energy through bilateral contracts instead of selling directly in the spot market.

Without imposing risk constraints, the best decision at a contract price of US$18/MWh is to sell all plant energy in the spot market. Figure 3.1 shows the distribution of plant discounted net revenue in this case. Note that in seven years its expected value is US82 MM but depending on the hydrological scenario it may be higher than US$400 MM. It can also be negative in low spot price scenarios.

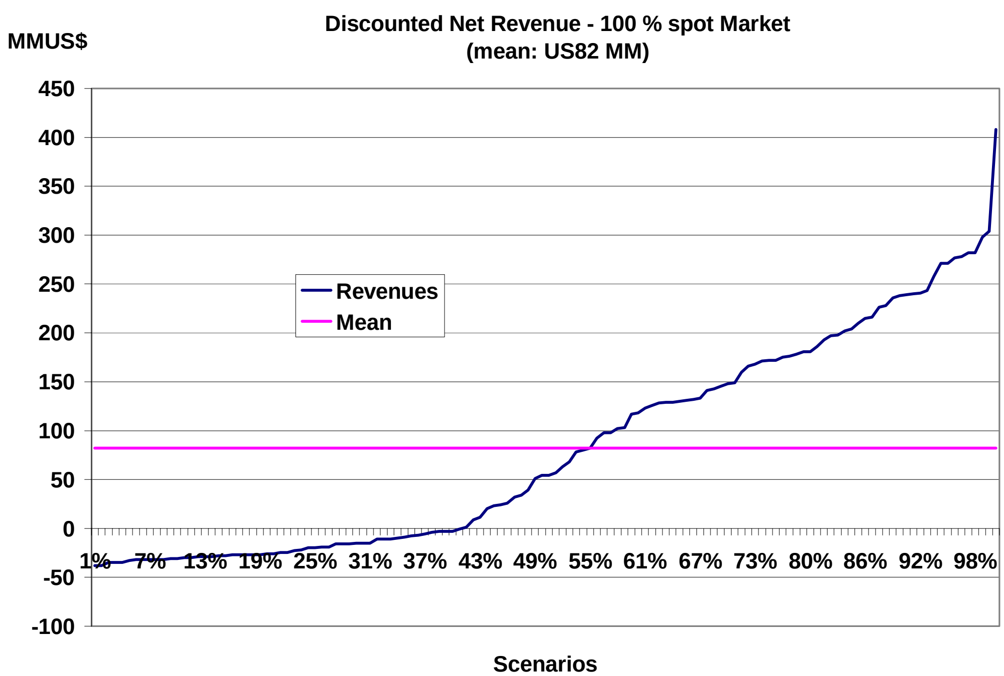
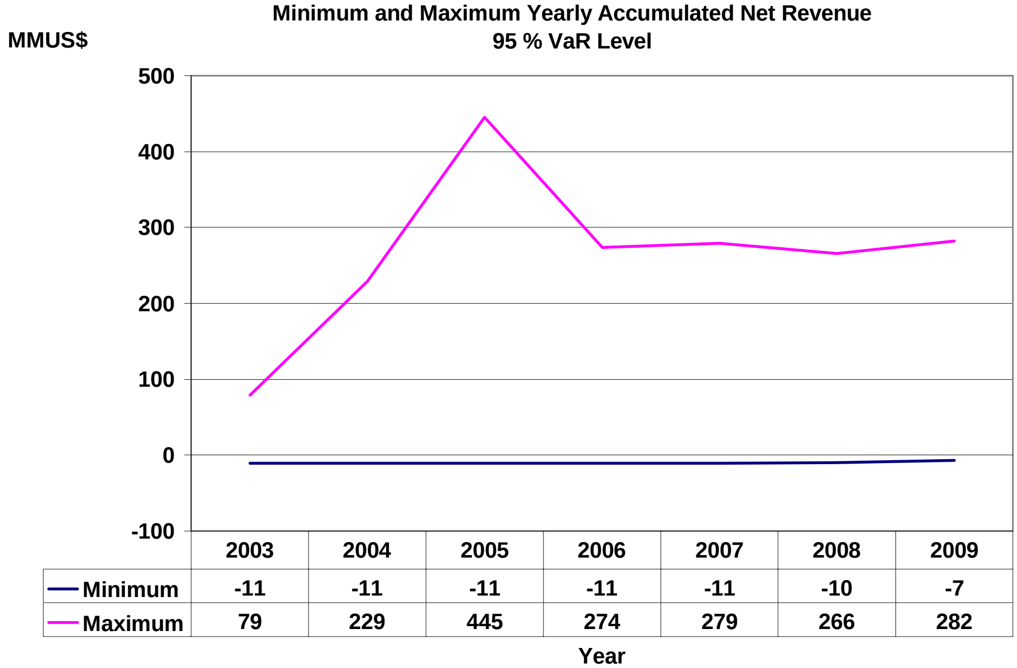


Figure 3.1 – Plant Net Discounted Net Revenue – 100 % Spot

Figure 3.2 shows plant minimum and maximum yearly-accumulated net revenues at a VaR level of 95 %. There are high revenue upsides but they can also be negative. The downside risk is associated to low spot price scenarios when plant revenues may not be sufficient to cover its fixed operating costs.



	2003	2004	2005	2006	2007	2008	2009
Minimum	-11	-11	-11	-11	-11	-10	-7
Maximum	79	229	445	274	279	266	282

Figure 3.2 – Minimum and Maximum Accumulated Net Revenues at a 95 % VaR Level – 100 % Spot

Next, a risk constraint is imposed requiring that yearly-accumulated net revenues should be positive at a 95 % VaR level. The best decision in this case is to sign a bilateral contract corresponding to 54 % of plant available capacity and sell the remaining energy in the spot market. Figure 3.3 shows the distribution of plant discounted net revenue in this case. As a result of selling 54 % of plant energy through a US$ 18/MWh bilateral contract the expected value of plant discounted net revenue decreased to US$ 70 MM, its upsides are smaller than in preceding case but now it is positive in all scenarios. Figure 3.4 shows plant minimum and maximum yearly-accumulated net revenues at a VaR level of 95 %. They are now greater than zero at a VaR level of 95 %, at the expense of a lower revenue upside. Bilateral contract at US$ 18/MWh is not as profitable as selling energy in the spot market but it is a good instrument for risk hedging when spot price is low.

By considering a contract price at US 20/MWh the best decision in this case is to sell 100 % of plant energy through bilateral contract with or without risk constraints.

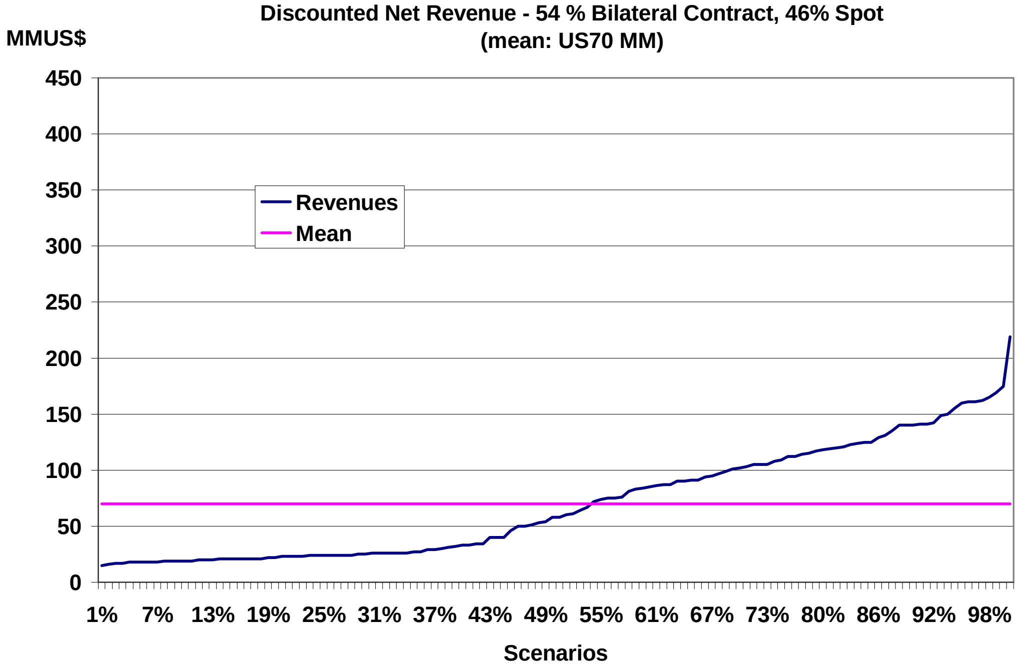
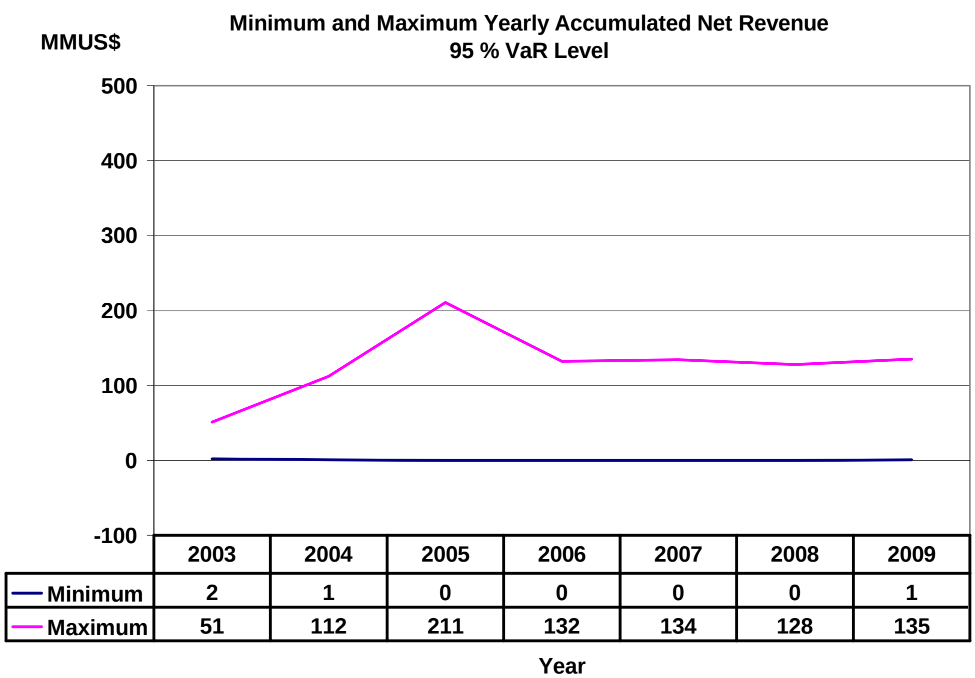


Figure 3.3 – Plant Net Discounted Net Revenue – 54 % Bilateral Contract, 46 % Spot



	2003	2004	2005	2006	2007	2008	2009
Minimum	2	1	0	0	0	0	1
Maximum	51	112	211	132	134	128	135

Figure 3.4 – Minimum and Maximum Accumulated Net Revenues at a 95 % VaR Level – 54 % Bilateral Contract, 46 % Spot

Besides bilateral contracts let us consider the possibility of selling energy options. To begin we consider option prices computed at 6% discount rate.

For a contract price at US$20/MWh and no risk constraint the best decision is to sell firm energy options with strike of US$30/MWh, up to 100 % of plant available capacity. Figure 3.5 shows the distribution plant discounted net revenue, in this case. Depending on the hydrological scenario, it can go from US$49 MM to US$ 353 MM but its expected value is US$ 96 MM. By selling the option the plant receives the associated monthly payment and also has the possibility to sell energy in the spot when it is profitable, during that acquisition period. In the performance period, if spot price is less than US$30/MWh it is free so sell its energy in the spot, whereas if spot price is greater than US$30/MWh it has to sell at US$30/MWh. This explains plant net revenues volatility as a result spot prices volatility. Net revenue upsides are not as high as when all plant energy is sold in the spot market (see Figure 3.1) but it is positive in all hydrological scenarios. The expected value of plant discounted net revenue in this case is greater than when all its energy is sold in the spot because it was used a discount factor of 12 % whereas option prices were computed based on 6% discount rate.

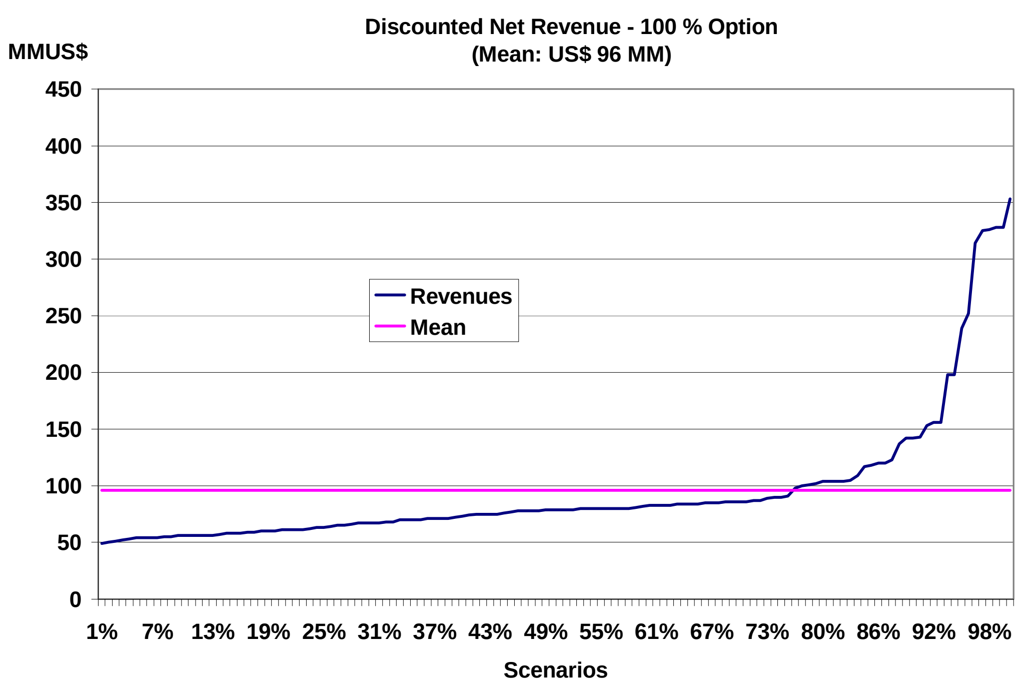
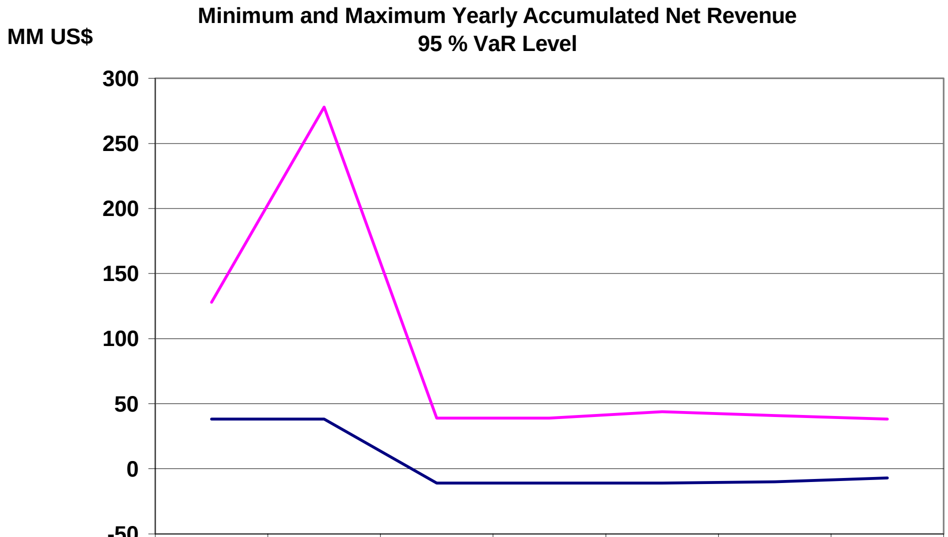


Figure 3.5 – Plant Net Discounted Net Revenue – 100 % Option, Strike: US $ 30/MWh

Figure 3.6 shows plant minimum and maximum yearly-accumulated net revenues at a VaR level of 95 %. In the first two years they are greater than zero due to the option monthly payment and the extra revenue from selling energy at the spot market. After that, the downside risk is associated to low spot price scenarios when plant revenues may not sufficient to cover its fix operating costs. In this case maximum losses at 95 % VaR level may reach US$11MM from the third to the fifth year.



	2003	2004	2005	2006	2007	2008	2009
Minimum	38	38	-11	-11	-11	-10	-7
Maximum	128	278	39	39	44	41	38

Year

Figure 3.6 – Minimum and Maximum Accumulated Net Revenues at a 95 % VaR Level – 100 % option

Next, a risk constraint is imposed such that minimum yearly-accumulated revenues should be greater than zero in all years. In this case the best solution is to sell 59 % of plant available capacity in firm energy option with strike of US$30/MWh, 41% in bilateral contracts and 0% in the spot. Bilateral contract at US$ 20/MWh is not as profitable as the option but it is a good instrument for risk hedging when spot price is low. Figure 3.7 shows the distribution of net discounted revenue in this case. Note that its mean value (US$ 93MM) is slightly less than in the preceding case but its minimum value is higher. Figure 3.8 shows plant minimum and maximum yearly-accumulated net revenues at a VaR level of 95 % for this case. Now they are greater than zero, in all years at the expense of a smaller upside – for instance, they dropped from US$ 278 to US$ 172 MM in the second year.

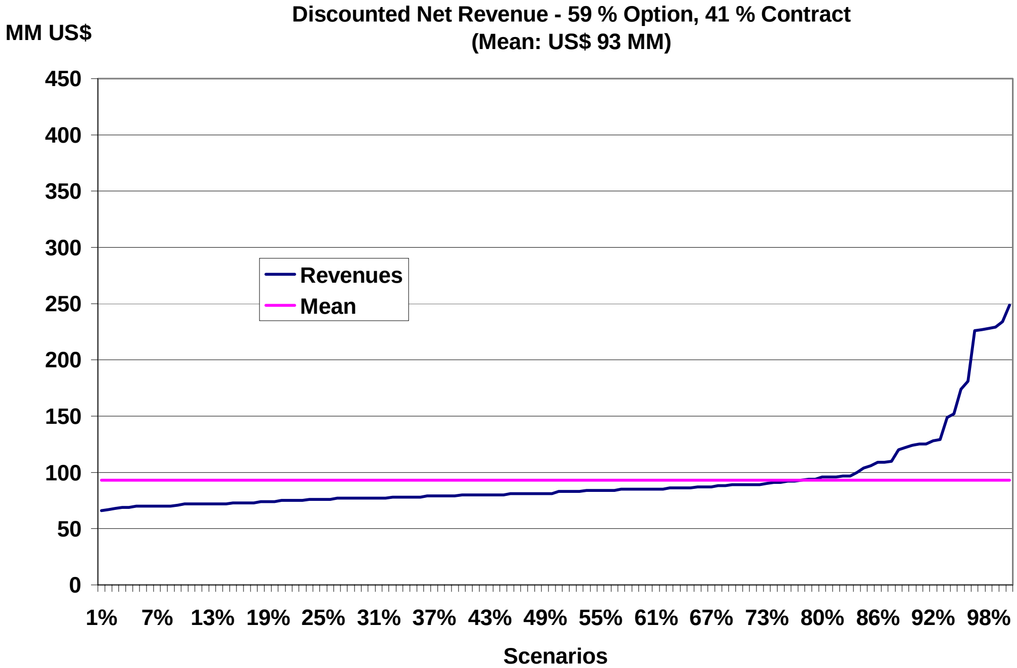
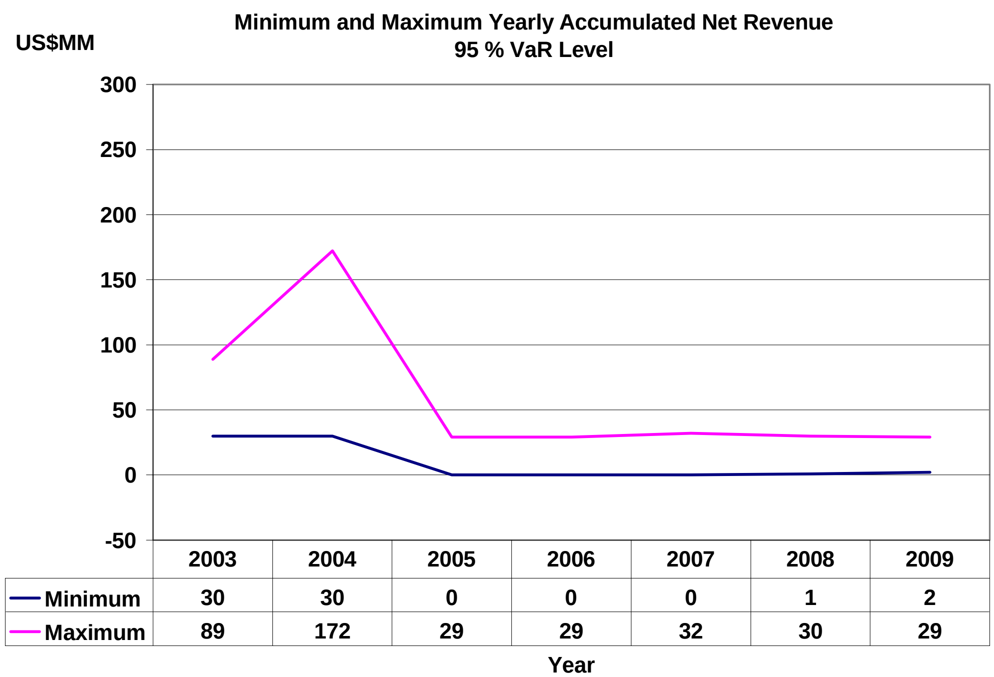


Figure 3.7 – Plant Net Discounted Net Revenue – 59 % Option, 41 % Bilateral Contract



	2003	2004	2005	2006	2007	2008	2009
Minimum	30	30	0	0	0	1	2
Maximum	89	172	29	29	32	30	29

Figure 3.8 – Minimum and Maximum Accumulated Net Revenues at a 95 % VaR Level – 59 % Option, 41 % Bilateral Contract

At US$ 22/MWh the best decision is to sell all plant output through bilateral contracts.

Similar trade-offs were also computed for option price computed at 12 % discount rate. Table 3.1 presents a summary of the above results and the ones with an option price computed at a 12 % discount rate

Contract Price (US$/MWh)	Option Price Discount Rate (%)	Risk Constraints (Yes/No)	Bilateral Contract (%)	Option (Strike) (%)	Spot (%)	Discounted Net Revenue Expected Value (MMUS$)
18	NA (*)	No	0%	Forbidden	100	81.7
18	NA (*)	Yes	54	Forbidden	46	70.2
20	NA (*)	Yes	100	Forbidden	0	90.4
20	6	No	0	100 (US$30/MWh)	0	95.5
20	6	Yes	41	59 (US$30/MWh)	0	93.4
22	6	Yes	100	0	0	120.5
20	12	Yes	100	0	0	90.4
18	12	No	0	100 (US$200/MWh)	0	81.7
18	12	Yes	54	46 (US$200/MWh)	0	70.2

(*) Not Applicable

Table 3.1 – Trade-off – Bilateral Contracts, Options and Spot

To summarize the results of this section, for the horizon ranging from 2003 to 2009 and a 12 % discount rate we get:

1. Trade-off between bilateral contracts and spot:

    - At a price of US$ 18/MWh and no risk constraints the best decision is to sell energy in the spot, whereas if risk constraints are imposed a percentage of plant energy should be sold through bilateral contracts;
    - At a price of US$ 20/MWh the best decisions is to sell all plant energy through bilateral contracts with risk constraints or not.

2. Trade-off among bilateral contracts, options with price computed using 6% discount rate and spot:
    - At a price of US$ 20/MWh and no risk constraints the best decision is to sell 100 % of plant available capacity in energy options (US$30/MWh strike price), whereas if risk constraints are imposed less than 100 % of plant available capacity should be sold in energy options and the remaining capacity should be committed with bilateral contracts.
3. Trade-off among bilateral contracts, options with price computed using 12% discount rate and spot:
    - At a price of US$ 18/MWh and no risk constraints the best decision is to sell 100 % of plant available capacity in energy options (US$200/MWh strike price), whereas if risk constraints are imposed less than 100 % of plant available capacity should be sold in energy options and the remaining capacity should be committed with bilateral contracts.

From Table 2.1 of the preceding section it can be seen that option prices increase from the early to the latter performance periods. This implies that for the latter periods the trade-off between bilateral contracts and options occurs at a higher contract price. For instance considering the horizon from 2003 to 2029 (not in Table 3.1), at a price of US$27/MWh and no risk constraints the best decisions is to commit 100 % of plant available in firm energy options when its price is computed based on 6% discount rate. For option price computed using the 12 % discount rate, the trade-off occurs at a contract price of US$25/MWh, which is higher than US$18/MWh shown in Table 3.1

3.2. TERMAL PLANT – OPEN CYCLE

The combined cycle plant chosen has 151 MW of nominal capacity and a mean available capacity of 122.7 MW. Its variable operating cost is US$ 18.44/MWh and it was assumed a fixed operating cost of US$ 2.00/kW.month.

The period of analysis is from January 2003 to December 2009.

In the first kind of evaluation we determine at which contract price it is better to sell energy through bilateral contracts instead of selling directly in the spot market.

Again, without imposing risk constraints, the best decision at a contract price of US$18/MWh is to sell all plant energy in the spot market. Figure 3.9 shows the distribution of plant discounted net revenue in this case. Note that in seven years its expected value is US19 MM but depending on the hydrological scenario it may be higher than US$120 MM. It can also be negative in low spot price scenarios. Also, due to the plant higher operating cost the revenue downside is here relatively higher than in the previous case.

Figure 3.10 shows plant minimum and maximum yearly-accumulated net revenues at a VaR level of 95 %. There are high revenue upsides but they can also be negative. Here again, the downside risk is associated to low spot price scenarios when plant revenues may not be sufficient to cover its fixed operating costs.

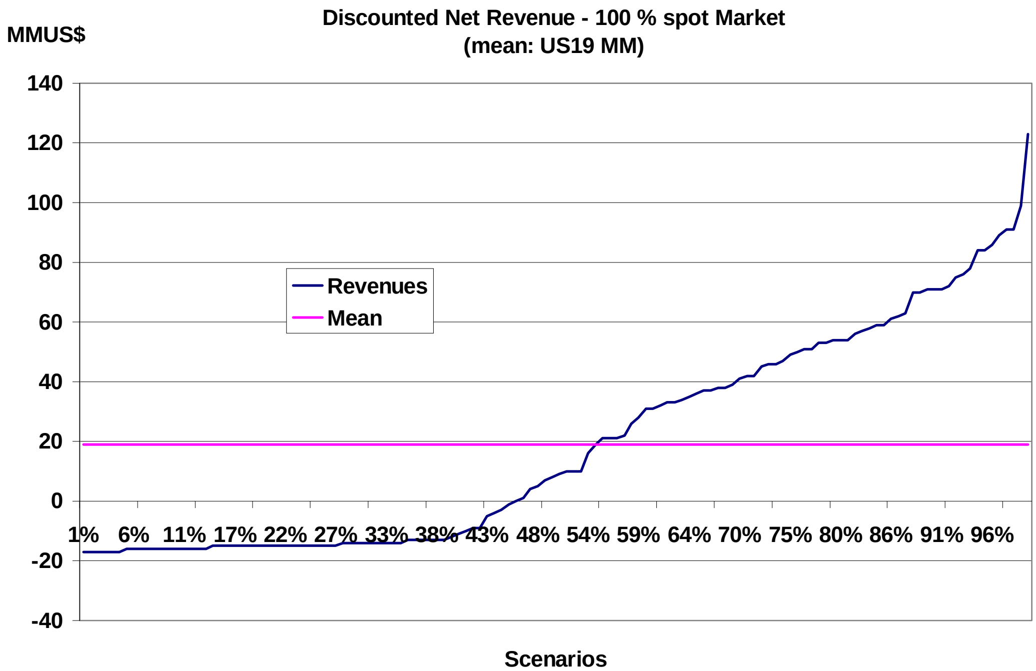
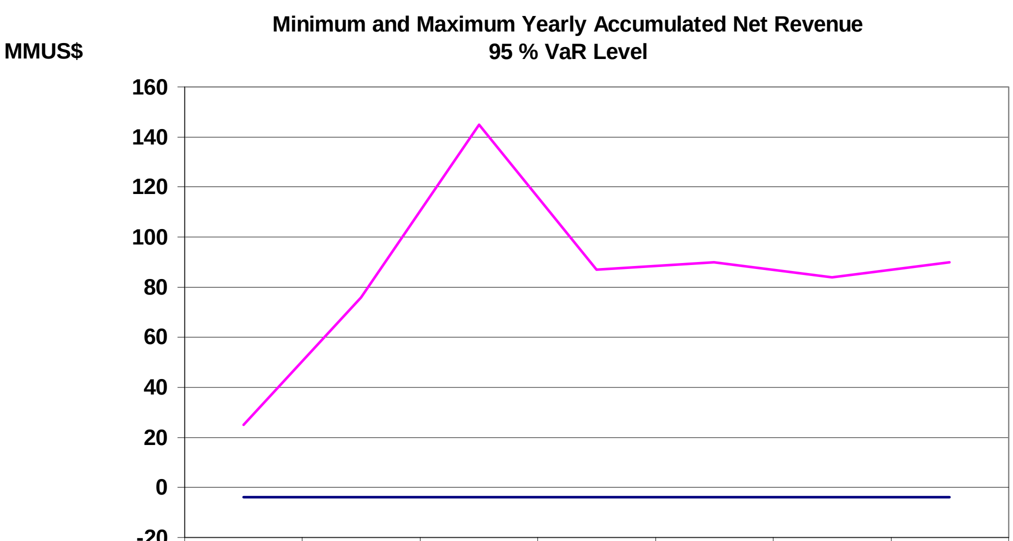


Figure 3.9 – Plant Net Discounted Net Revenue – 100 % Spot



	1	2	3	4	5	6	7
Minimum	-4	-4	-4	-4	-4	-4	-4
Maximum	25	76	145	87	90	84	90

Year

Figure 3.10 – Minimum and Maximum Accumulated Net Revenues at a 95 % VaR Level – 100 % Spot

Now, contrary to the previous case, there were no way to impose here that the yearly accumulated revenue should be greater or equal zero or even US$ -2 MM, at a 95 % VaR level, by just using a contract at US$ 18/MWh. As this contract price energy price is lower than variable plant operating cost (US$18.44/MWh) it may not even cover plant variable operating cost in some scenarios.

By considering a contract price at US 20/MWh the best decision in this case is to sell 100 % of plant energy through bilateral contract with or without risk constraints. Where risk constraints was specified as yearly losses should be limited to US$ 2 MM at 95 % VaR level.

Besides bilateral contracts let us consider the possibility of selling energy options. To begin with we consider option prices computed at 6% discount rate.

For a contract price at US$20/MWh and no risk constraint the best decision is to sell firm energy options with strike of US$30/MWh, up to 100 % of plant available capacity. Figure 3.11 shows the distribution plant discounted net revenue, in this case. Depending on the hydrological scenario, it can go from US$13 MM to US$ 113 MM but its expected value is US$ 24 MM.

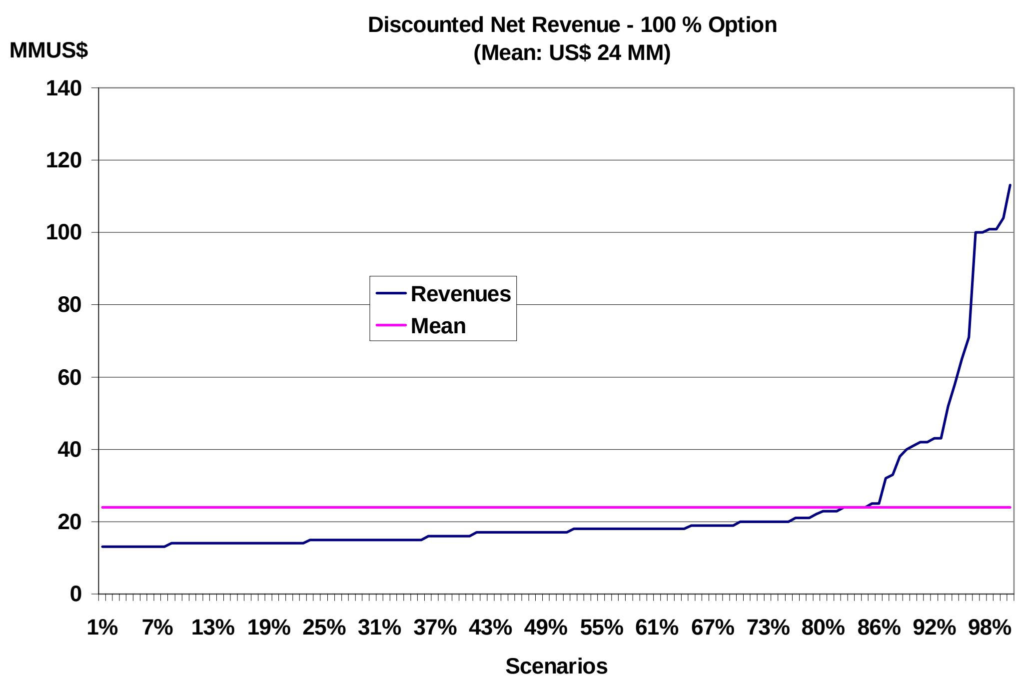
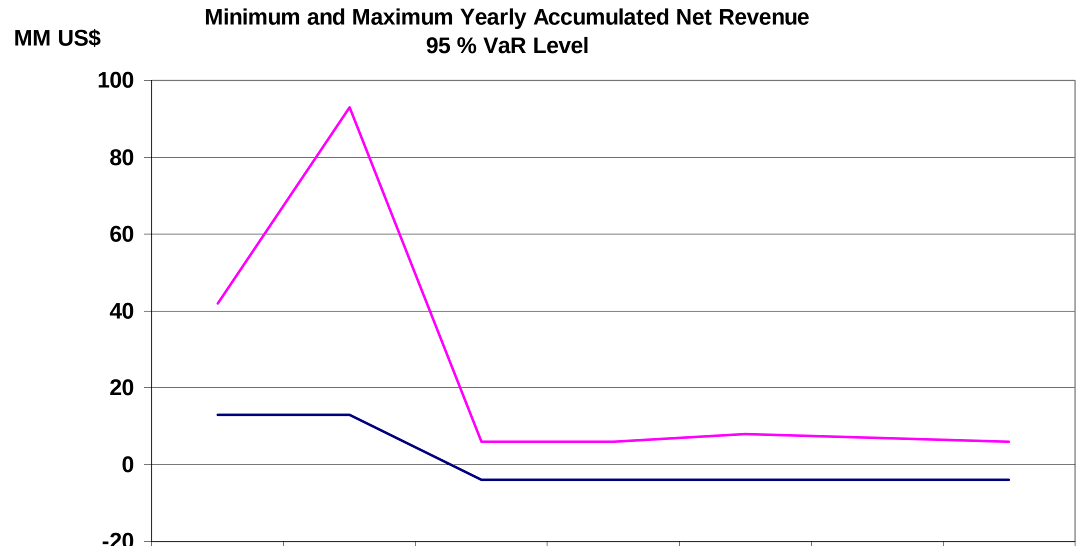


Figure 3.11 – Plant Net Discounted Net Revenue – 100 % Option

Figure 3.12 shows plant minimum and maximum yearly-accumulated net revenues at a VaR level of 95 %. In the first two years they are greater than zero due to the option monthly payment and the extra revenue from selling energy at the spot market. After that, the downside risk is associated to low spot price scenarios when plant revenues may not sufficient to cover its fix operating costs. In this case maximum losses at 95 % VaR level may reach US$ 4 MM from the third to the fifth year.

As it was not possible to impose a risk constraint of no losses at 95 % VaR level in this case, due to the plant higher operating cost, the new risk constraints was specified as yearly losses should be limited to US$ 2 MM at 95 % VaR level.

In this case the best solution is to sell 52% of plant available capacity in firm energy option with strike of US$30/MWh, 48% in bilateral contracts and 0% in the spot. Bilateral contract at US$ 20/MWh is not as profitable as the option but it is a good instrument for risk hedging when spot price is low. Figure 3.13 shows the distribution of net discounted revenue in this case. Note that its mean value (US$ 23MM) is slightly less than in the preceding case but its minimum value is higher. Figure 3.14 shows plant minimum and maximum yearly-accumulated net revenues at a VaR level of 95 % for this case. Now they are greater than –US$2 MM, in all years at the expense of a smaller upside – for instance, they dropped from US$ 93 to US$ 51 MM in the second year.



	1	2	3	4	5	6	7
Minimum	13	13	-4	-4	-4	-4	-4
Maximum	42	93	6	6	8	7	6

Year

Figure 3.12 – Minimum and Maximum Accumulated Net Revenues at a 95 % VaR Level – 100 % Option

At US$ 22/MWh the best decision is to sell all plant output through bilateral contracts and in this case yearly net accumulated revenue is greater than zero at 95 % VaR level

Similar trade-offs were also computed for option price computed at 12 % discount rate. Table 3.2 presents a summary of the above results and the ones with option price computed at 12 % discount rate.

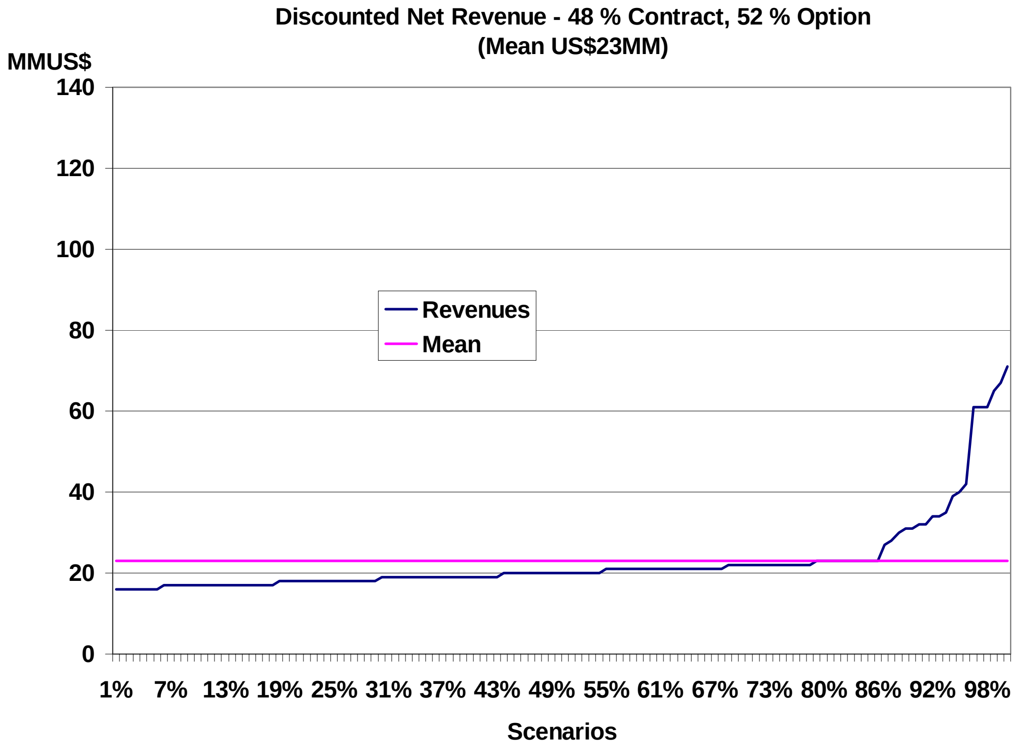


Figure 3.13 – Plant Net Discounted Revenue – 48% Contract, 52 % Option

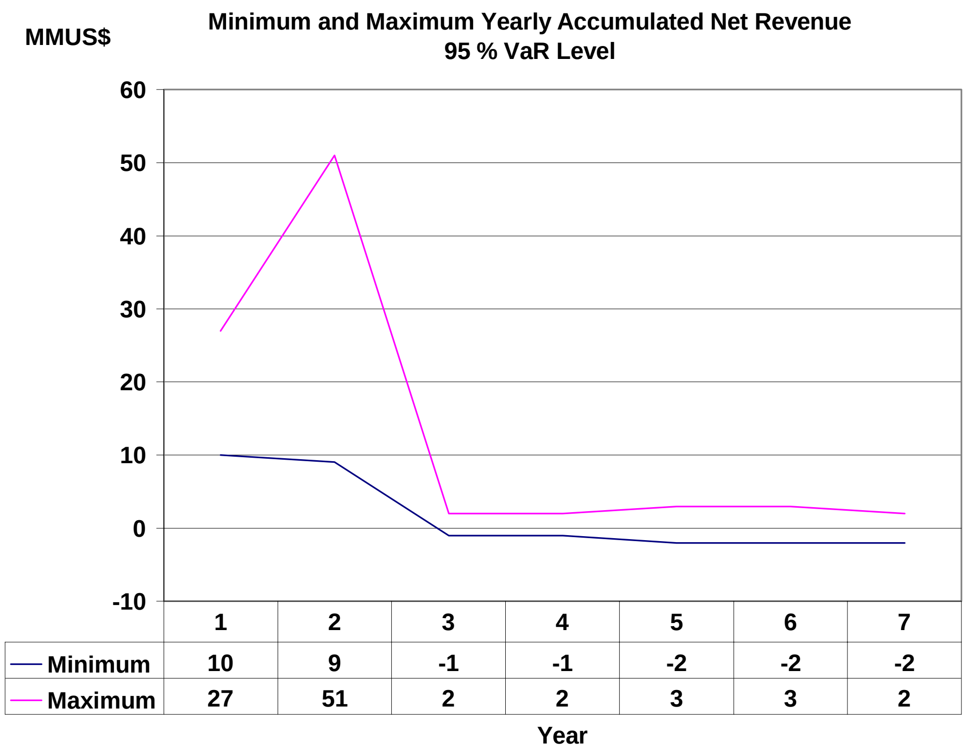


Figure 3.14 – Minimum and Maximum Accumulated Net Revenues at a 95 % VaR Level – 48 % Contract, 52 % Option

Contract Price (US$/MWh)	Option Price Discount Rate (%)	Risk Constraints (**) (Yes/No)	Bilateral Contract (%)	Option (Strike) (%)	Spot (%)	Discounted Net Revenue Expected Value (MMUS$)
18	NA (*)	No	0%	Forbidden	100	19
18	NA (*)	Yes	xxx	Forbidden	Xxx	Not possible
20	NA (*)	Yes	100	Forbidden	0	22
20	6	No	0	100 (US$30/MWh)	0	24
20	6	Yes	48	52 (US$30/MWh)	0	23
22	6	Yes	100	0	0	32.3
20	12	Yes	100	0	0	22
18	12	No	0	100 (US$200/MWh)	0	19
18	12	Yes	xxx	xxx	Xxx	Not possible

(*) Not Applicable

(**) **Risk constraints: At 95 % VaR level, yearly losses should be lesser than US$ 2 MM.**

To summarize the results of this section, for the horizon ranging from 2003 to 2009 and a 12 % discount rate we get:

1. Due to the plant higher operating cost a more relaxed version of risk constraint was considered for the open cycle plant
2. Trade-off between bilateral contracts and spot:
   - At a price of US$ 18/MWh and no risk constraints the best decision is to sell energy in the spot but in this case there were no way to imposing an even relaxed risk constraint due the plant high operating cost;
   - At a price of US$ 20/MWh the best decisions is to sell all plant energy through bilateral contracts with risk constraints or not.
3. Trade-off among bilateral contracts, options with price computed using 6% discount rate and spot:
   - At a price of US$ 20/MWh and no risk constraints the best decision is to sell 100 % of plant available capacity in energy options (US$30/MWh strike price), whereas if risk constraints are imposed less than 100 % of plant available capacity should be sold in energy options and the remaining capacity should be committed with bilateral contracts.

4. Trade-off among bilateral contracts, options with price computed using 12% discount rate and spot:
   - At a price of US$ 18/MWh and no risk constraints the best decision is to sell 100 % of plant available capacity in energy options (US$200/MWh strike price), but at this contract price there were no way to impose risk constraints.

3.3. HYDRO PLANT

The hydro plant chosen has 1150 MW of installed capacity and 1053 MW of available capacity. Its dispatch for each time step, load level and hydrological scenario was directly taken from the SDDP runs which produced the spot scenarios presented in Chapter 2.

The period of analysis is also from January 2003 to December 2009 and option price is computed based on 6 % discount rate.

In the first kind of evaluation we consider a contract price of US$ 20/MWh and no risk constraints. The best decision is then to commit 100% of plant available capacity to firm energy options with strike price of US$30/MWh. Figure 3.15 shows the distribution of plant discounted net revenue for this case. Its expected value is US$438 MM but depending on the hydrological scenario it can go from –US$ 236 MM to US$ 770 MM. Figure 3.16 shows plant minimum and maximum yearly-accumulated net revenues at a VaR level of 95 % for this case. Note that in the years of 2003 and 2004 they are positive at a 95 % VaR level due to option price payments, but in 2006 the plant maximum losses, at 95 % VaR level, is US$ 473 MM which is higher that its expected discounted net revenue from 2003 to 2009.

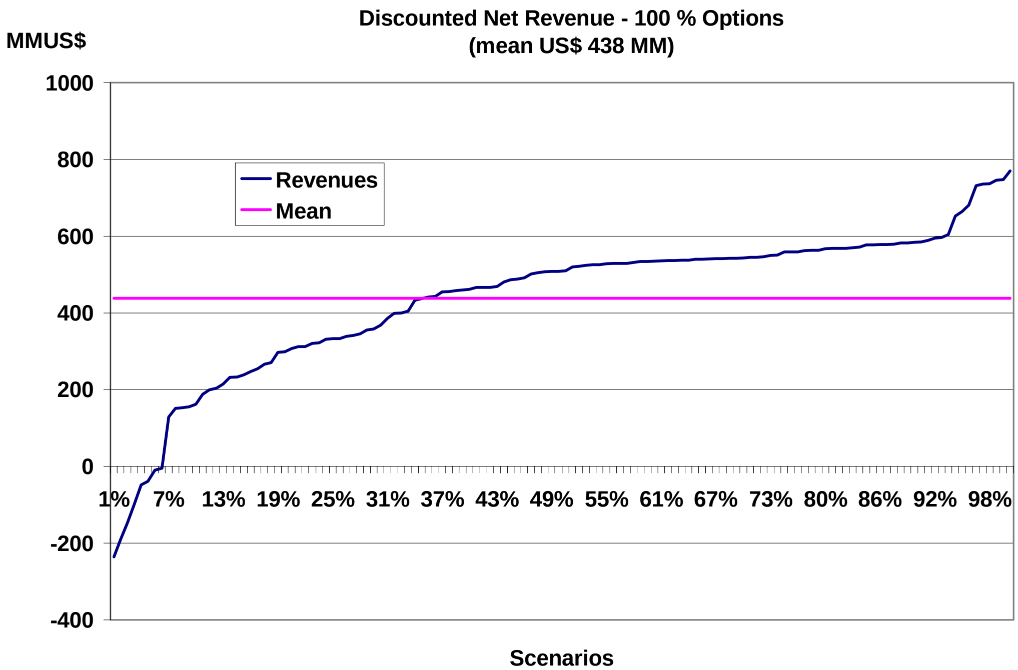
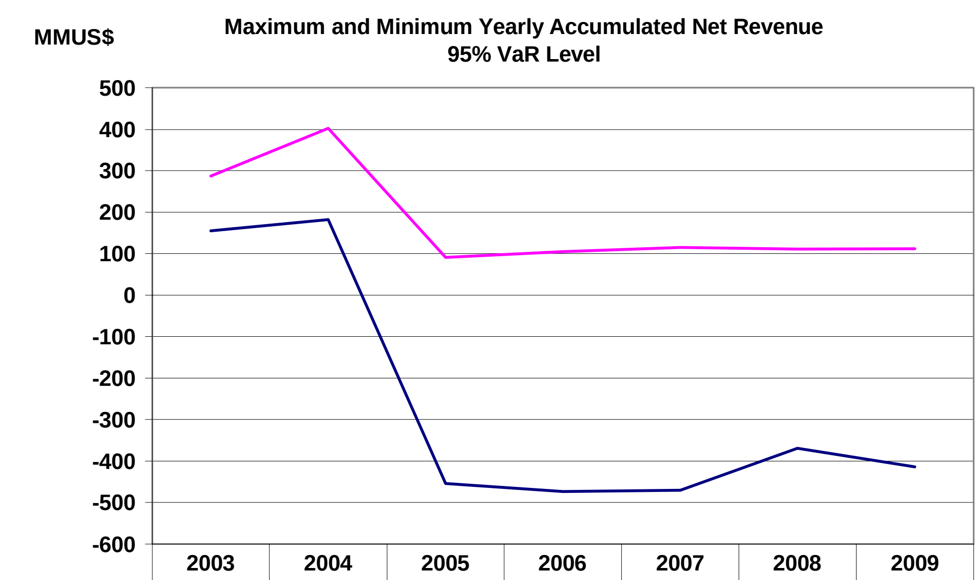


Figure 3.15 – Plant Net Discounted Net Revenue – 100 % Option



	2003	2004	2005	2006	2007	2008	2009
Minimum	155	182	-454	-473	-470	-369	-414
Maximum	287	402	91	105	115	111	112

Year

Figure 3.16 – Minimum and Maximum Accumulated Net Revenues at a 95 % VaR Level – 100 % Option

The downside risk for the hydro plant is not only related to low spot price scenarios but also with high spot scenarios. This because there is a negative correlation between spot prices and stored energy in predominantly hydro systems. This implies that when spot prices are high hydro production may be low. Then when committing 100 % of plant available capacity to firm energy options the agent may need to buy energy in the spot market to meet contract obligations, when the prices in this market are high.

Next, a risk constraint is imposed such that maximum annual losses should be less than US$ 200 MM at a 95 % VaR level. The best decision is then to commit only 59 % of plant energy capacity to firm energy option (US$ 30 /MWh strike price) and leave 41 % of plant capacity to produce energy for selling in the spot market. Figure 3.17 shows the distribution of plant discounted net revenue in this case. Its expect value is US$ 421 MM and it is positive in all hydrological scenarios.

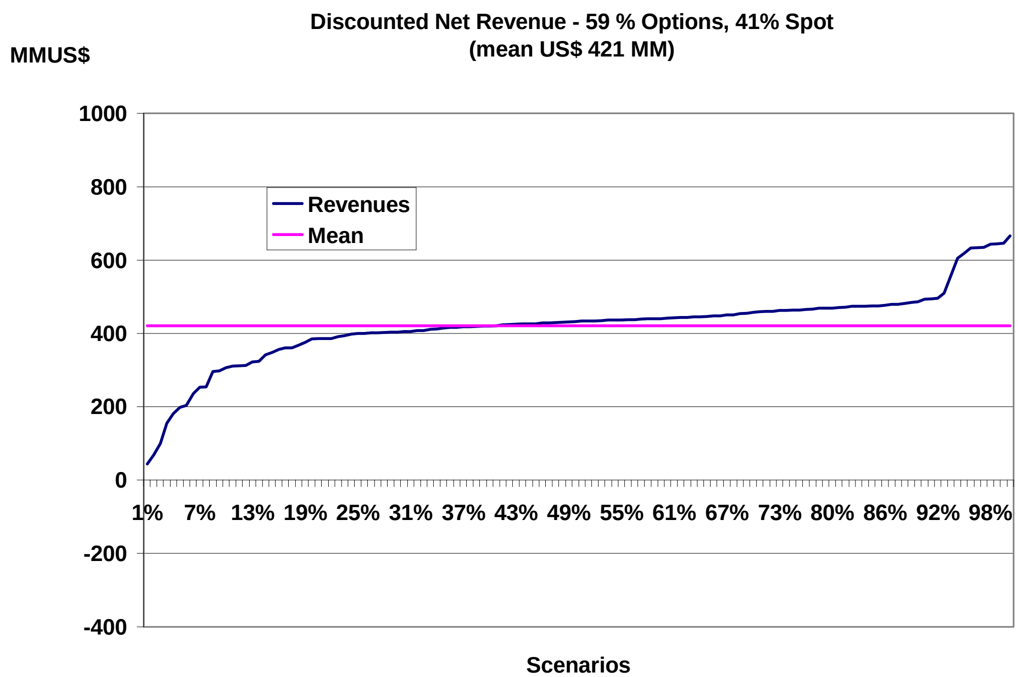


Figure 3.17 – Plant Net Discounted Net Revenue – 59 % Option, 41 % Spot

Figure 3.18 shows plant minimum and maximum yearly-accumulated net revenues at a VaR level of 95 % in this case. As shown in the figure the maximum losses at a VaR level of 95 % is limited to US$200 MM. But now revenue upsides are smaller than in the preceding case.

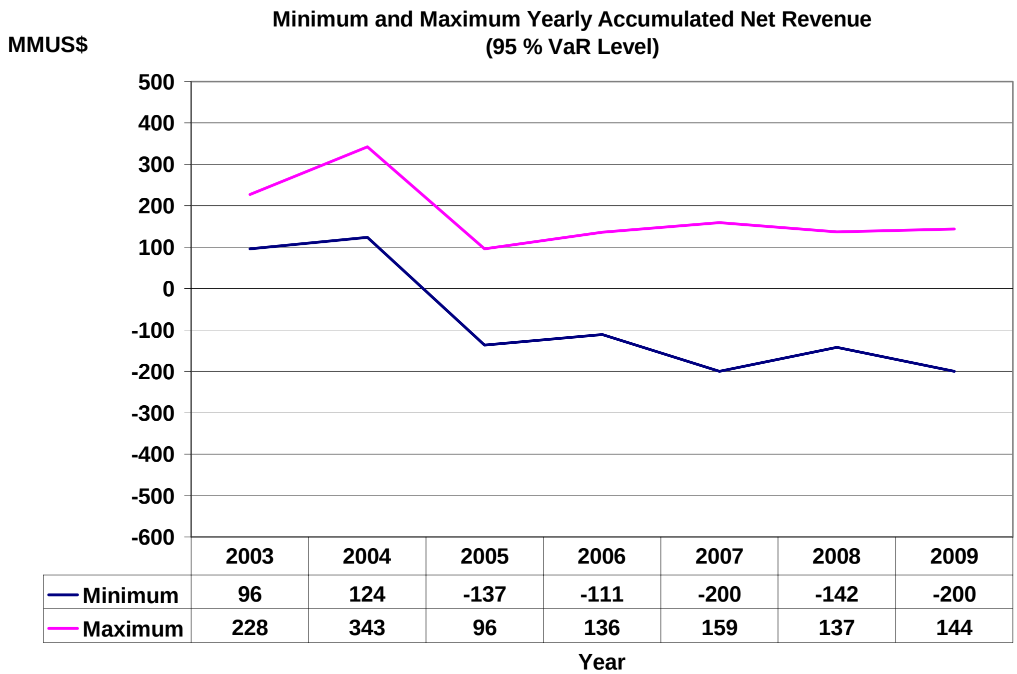
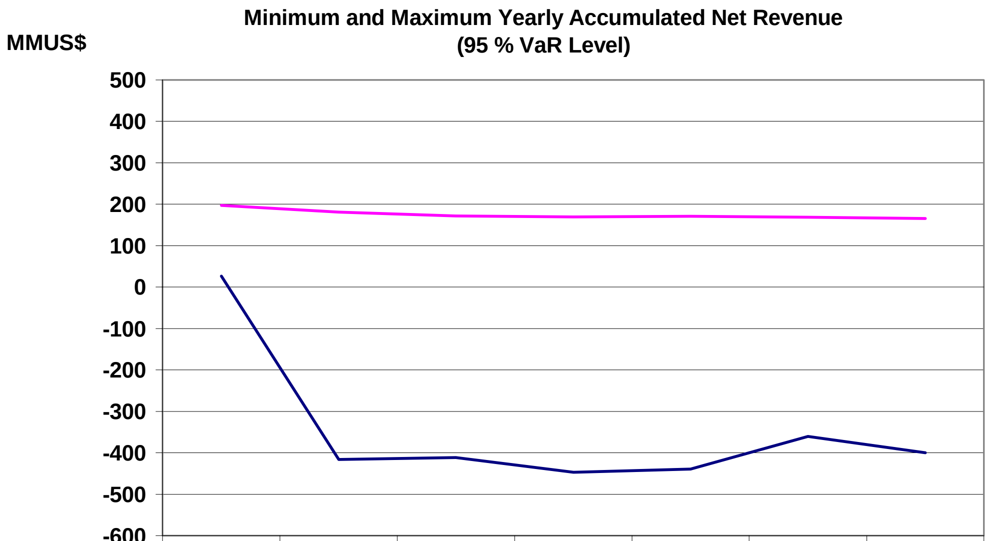


Figure 3.18 – Minimum and Maximum Accumulated Net Revenues at a 95 % VaR Level – 59 % Option, 41 % Spot

With contact price at US $ 22/MWh and no risk constraints the best decision is to sign a bilateral contract corresponding to 100 % of plant available capacity. Figure 3.19 shows the yearly-accumulated net revenue in this case. Note that from 2004 to 2009 maximum losses are greater than US$ 350 MM. By imposing the same risk constraints the best decision in this case is to only sign bilateral contract in the amount of 22 % of plant available capacity and leave the remaining plant production to the spot market



	2003	2004	2005	2006	2007	2008	2009
Minimum	27	-416	-412	-447	-439	-361	-400
Maximum	198	181	172	169	171	168	166

Figure 3.19 – Minimum and Maximum Accumulated Net Revenues at a 95 % VaR Level – 100 % Bilateral Contract

Now suppose that contract price is US 28 /MWh but a risk constraint is imposed such that at a VaR level of 95 % yearly accumulated revenues should be greater than US$ 50 MM in 2003 and 2004 and losses should be limited to US$ 200 MM in the remaining years. The best decision in this case is to sell firm energy options (strike: US $ 30/MWh) in the amount of 20 % of plant available capacity, sign a contract in the amount corresponding to 43 % of plant available capacity and leave the remaining capacity for the spot market. The expected value for plant discounted net revenue is US$ 567 and Figure 3.20 shows the yearly accumulated net revenue in this case.

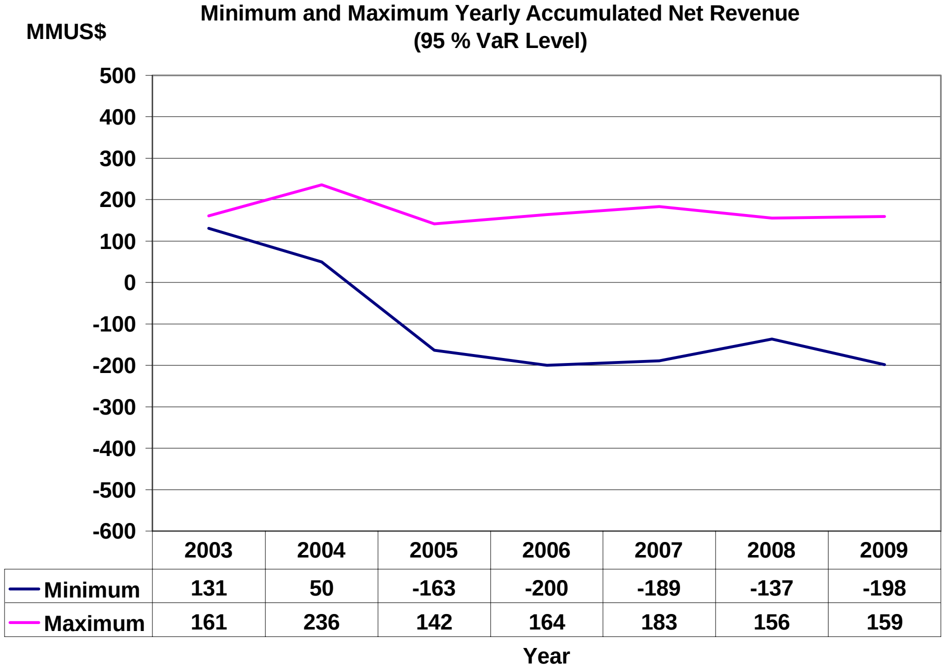


Figure 3.20 – Minimum and Maximum Accumulated Net Revenues at a 95 % VaR Level – 59 % option, 41 % spot

Table 3.2 presents a summary of the above results.

Contract Price (US$/MWh)	Option Price Discount Rate (%)	Risk Constraints (Yes/No)	Bilateral Contract (%)	Option (Strike) (%)	Spot (%)	Discounted Net Revenue Expected Value (MMUS$)
20	**6**	**No**	**0**	**100** **(US$30/MWh)**	**0**	**437.6**
20	**6**	**Yes (*)**	**0**	**59** **(US$30/MWh)**	**41**	**421.0**
22	**6**	**No**	**100**	**0**	**0**	**511.2**
22	**6**	**Yes (*)**	**22**	**0**	**78**	**422.3**
28	**6**	**Yes (**)**	**43**	**20** **(US$30/MWh)**	**37**	**567.4**

(*) Risk Constraint: At 95 % VaR level, maximum annual losses should be smaller than US$ 200 MM

(**) Risk Constraint: At 95 % VaR level, yearly-accumulated net revenue should be greater than US$ 50 MM in 2003 and 2004, and losses should be limited to US$ 200 MM in the remaining years

Table 3.2 – Trade-off – Bilateral Contracts, Options and Spot

To summarize the results of this section, for the horizon from 2003 to 2009 and a 12 % discount rate:

1. Trade-off among bilateral contracts, options with price computed using 6% discount rate and spot:

    - At a price of US$ 20/MWh and no risk constraints the best decision is to sell 100 % of plant available capacity in energy options (US$30/MWh strike price), whereas if risk constraints is imposed less than 100 % of plant available capacity should be sold in energy options and the remaining capacity should be left to the spot markets due to the high risk of a hydro plant in high spot price scenarios.

3 At a price of US$ 22/MWh and no risk constraints the best decision is to sign a bilateral contract corresponding to 100 % of plant available capacity, whereas if risk constraints is imposed less than 100 % of plant available capacity should be committed to bilateral contracts and the remaining capacity should be used to produce energy for the spot markets due to the high risk of hydro plant with high spot price scenarios.

4 Depending on the kind of risk constraints it may be attractive to commit part of plant available capacity to firm energy option even at a contract price of US$ 28/MWh.

Here again for latter time periods the transition: option – bilateral occurs at a higher price. For instance if the whole horizon (from 2003 to 2029) were considered, at a price of US$27/MWh and no risk constraints the best decision would be to commit 100 % of plant available in firm energy options when its price is computed based on 6% discount rate

One important aspect related to hydro plants when selling energy options is the risk related not only with low spot scenarios but also with high spot scenarios. For the latter case the best hedging strategy is to leave part of plant production to the spot market.

4. ANALYSIS FOR THE NEW PLANTS

In the section we will consider firm energy option under the perspective of an agent that is about to make the decision to build a new power plant. He/she is going to do so if the internal rate of return associated to his/her investments is high enough at an acceptable level of risk. This kind of analysis is important to evaluate to what extent firm energy option can contribute to generation expansion, which is the regulators main concern.

In Section 4.1 it is determined at what price investors would be willing to sell energy options. These prices will be compared with the option market prices computed in Section 2. Energy option market will only develop if there are some agreements among these values. In Section 4.2 portfolio optimizations are carried out under different assumptions.

The type of new plant that will be considered is a combined cycle gas fired plant with the technical economic data shown in Table 4.1

Investment cost (100 % equity)	**$600/kW**
Construction time	**Two years**
Disbursement schedule	**40% first year, 60% second year**
Capacity	**500 MW**
Maximum available capacity factor	**92%**
O&M fixed costs	**US$ 2/kW.month**
Variable cost (O&M and fuel)	**US$ 15/MWh**
Minimum generation	**0% of capacity**
Lifetime	**25 years**

Table 4.1 – Plant Technical Economic Data

Plant total investment cost is US$ 300 MM, with the following disbursements: US$ 120 MM in the first year and US$ 180 MM in the second year. In general case there are some loan schemes to build a power plant but no assumptions were made here with respect to that.

4.1. INVESTOR REQUIRED OPTION PRICE

In this section we examine at what price investors would be willing to sell the kind of energy option specified in Section 2. When selling the option he or she will receive the monthly payment during the acquisition periods. On the other hand, during the performance periods, the energy produced by the plant will be sold at the strike price if the spot is greater than the strike, otherwise, it will be sold at the spot price. In this computation the price of the options will be the same in all acquisition periods. Plant dispatch rule is: dispatch at the available capacity if spot is greater than plant variable cost, otherwise dispatch at the minimum generation.

The computation will be carried out based on a required free of tax mean internal rate of return of 15%. Figures 4.1 to 4.5 shows the result for the five strike prices.

Note again that as the strike price increases the required price decreases, as there is higher probability that plant output can be sold at the spot market at higher prices. Also, the internal rate return is more volatile for the higher strike prices, as there is a higher exposure of the plant to the spot price variations.

Figures 4.6 to 4.10 show a comparison between the market price and investor required price for the four strike prices and two discount rates used to compute option market prices. Observe that even though investor required option prices are higher than market prices for the first or second performance periods they are smaller than market prices for the other performance periods even when theses prices are computed based on the 12% discount rate.

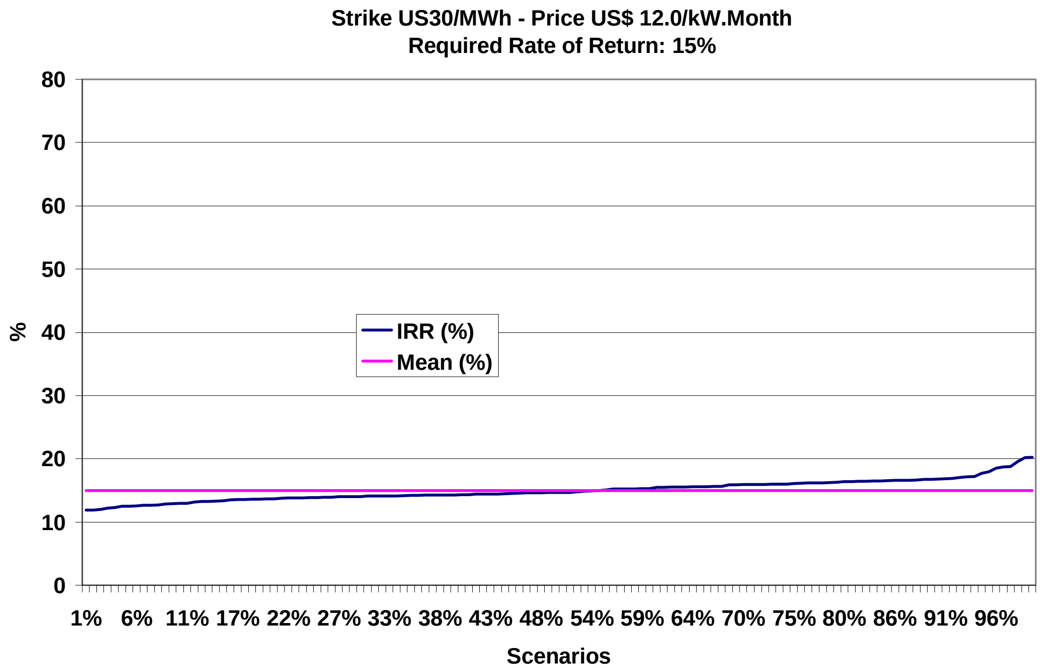


Figure 4.1 – Required Price – Strike Price – US 30/MWh

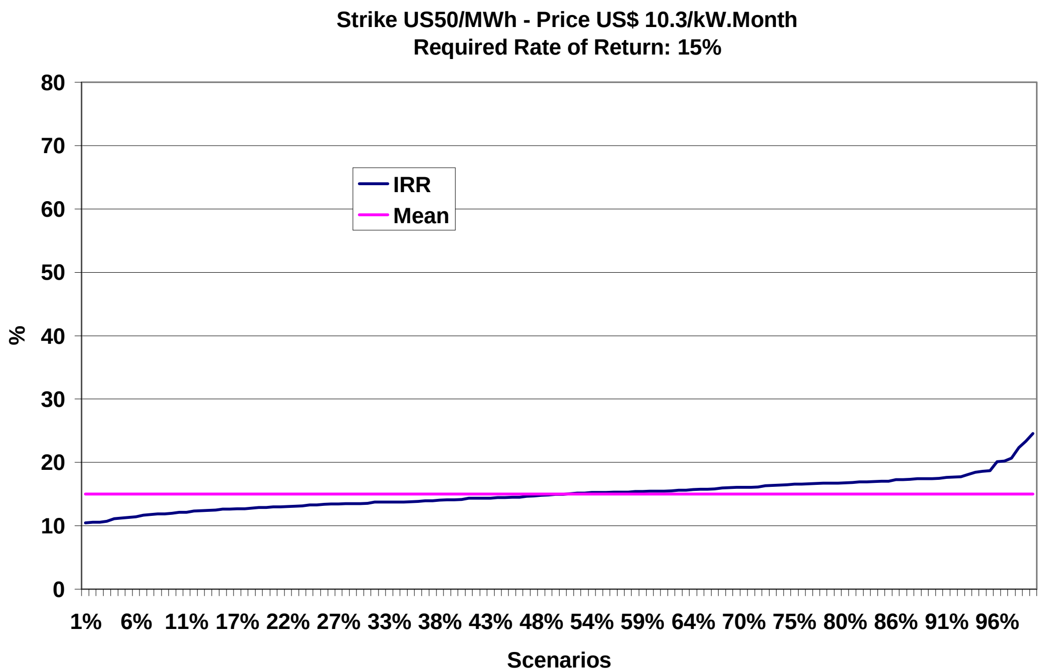


Figure 4.2 – Required Price – Strike Price – US 50/MWh

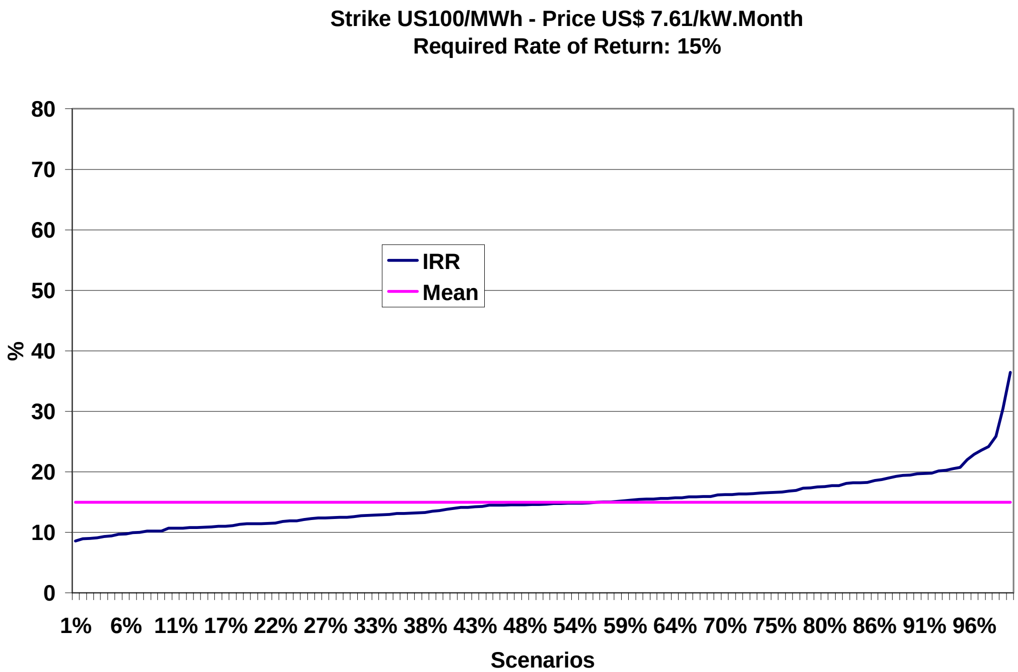


Figure 4.3 – Required Premium – Strike Price – US 100/MWh

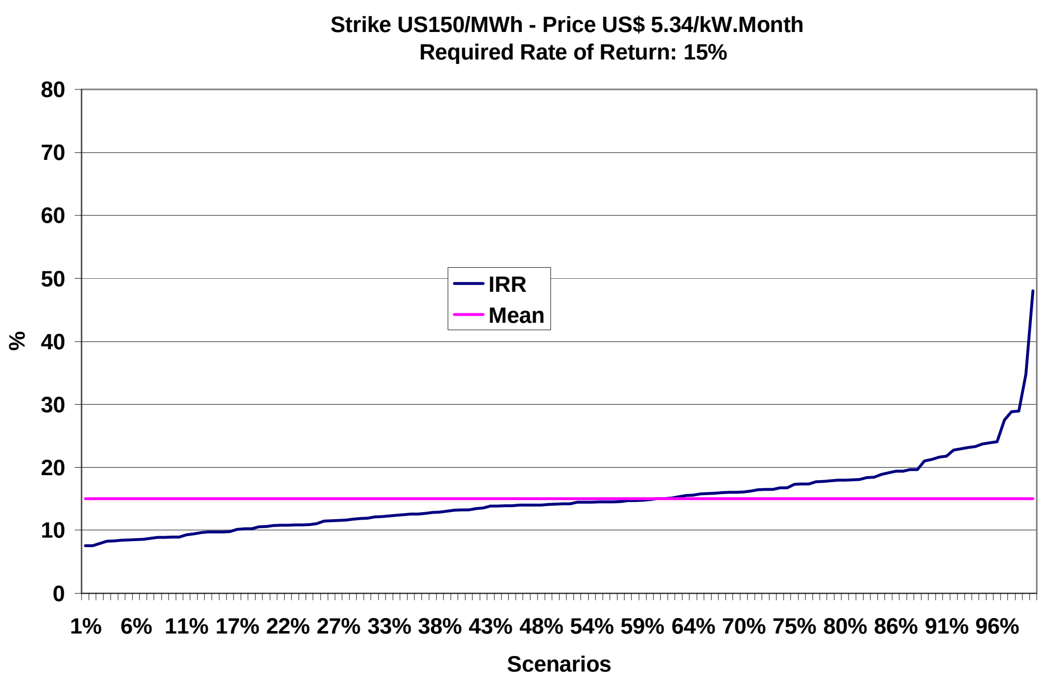


Figure 4.4 – Required Price – Strike Price – US 150/MWh

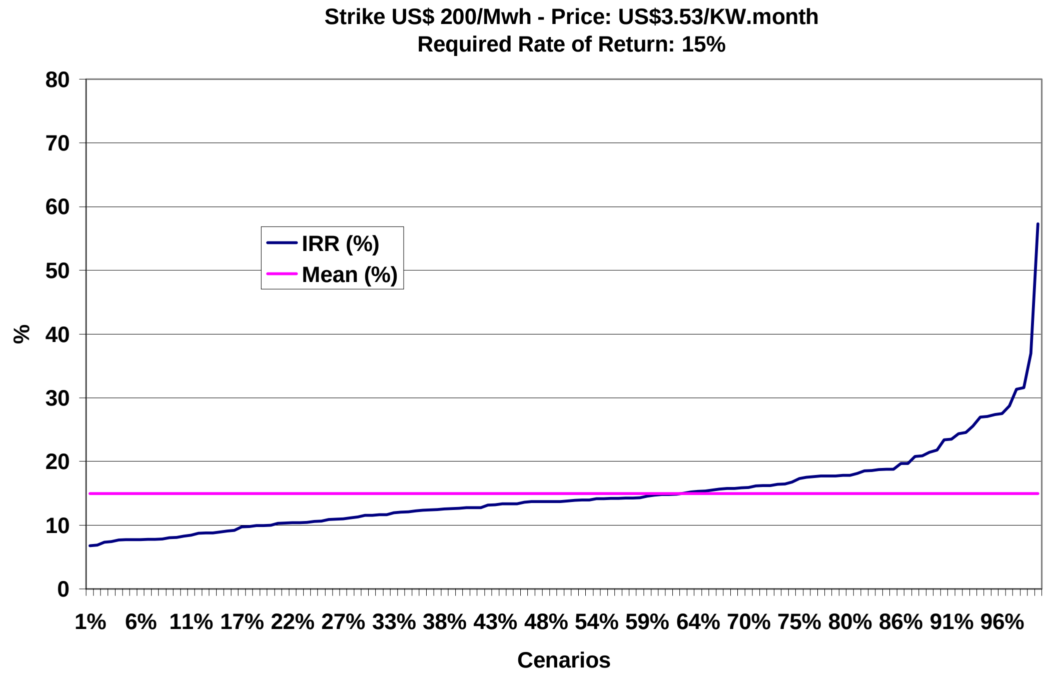


Figure 4.5 – Required Price – Strike Price – US 200/MWh

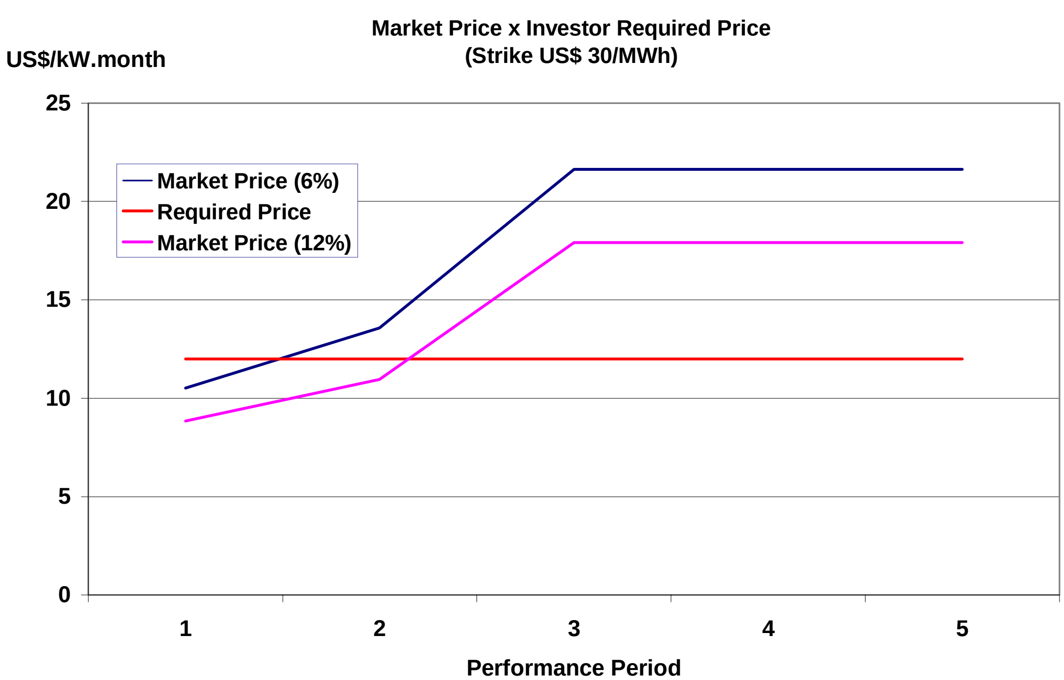


Figure 4.6 – Market Price x Investor Required Price – Strike – US30/MWh

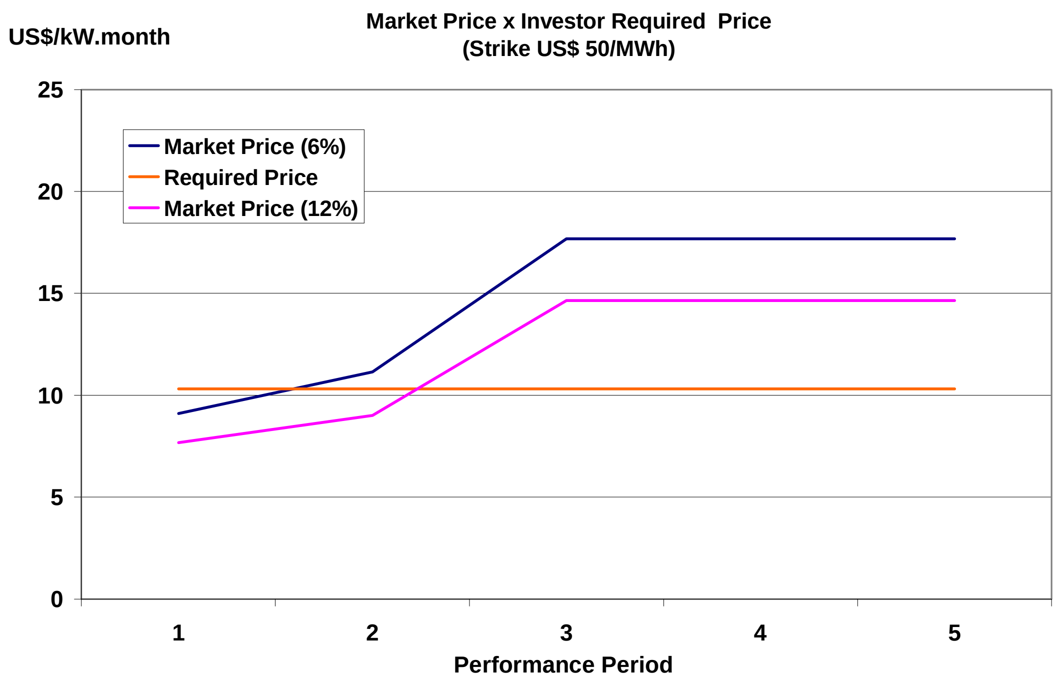


Figure 4.7 – Market Price x Investor Required Price – Strike – US50/MWh

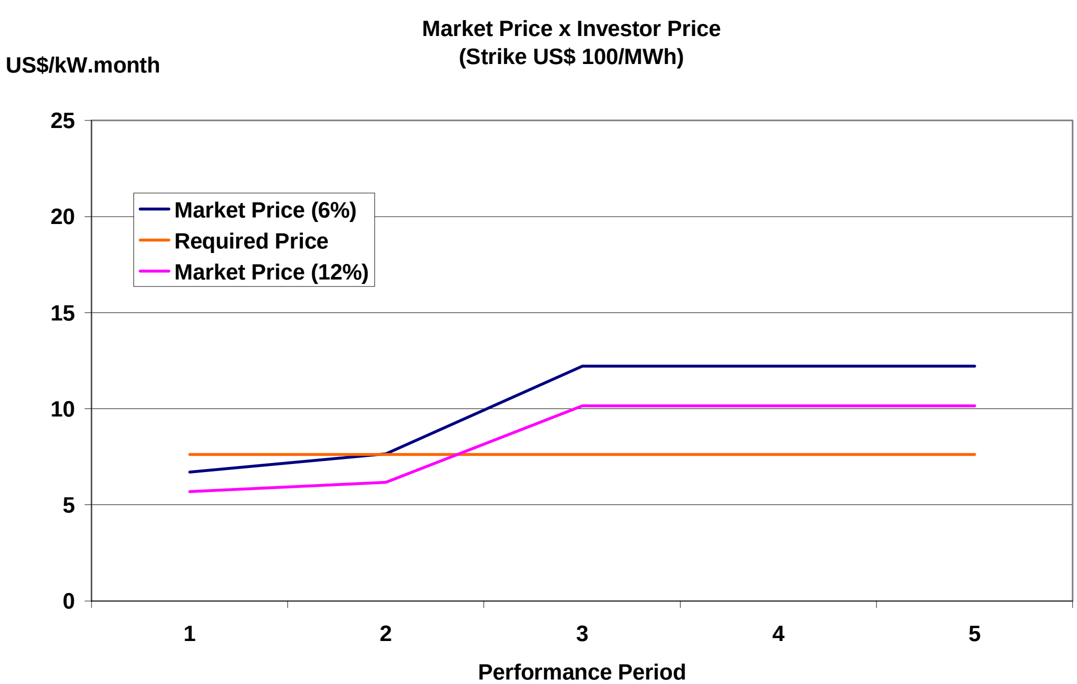


Figure 4.8 – Market Price x Investor Required Price – Strike – US100/MWh

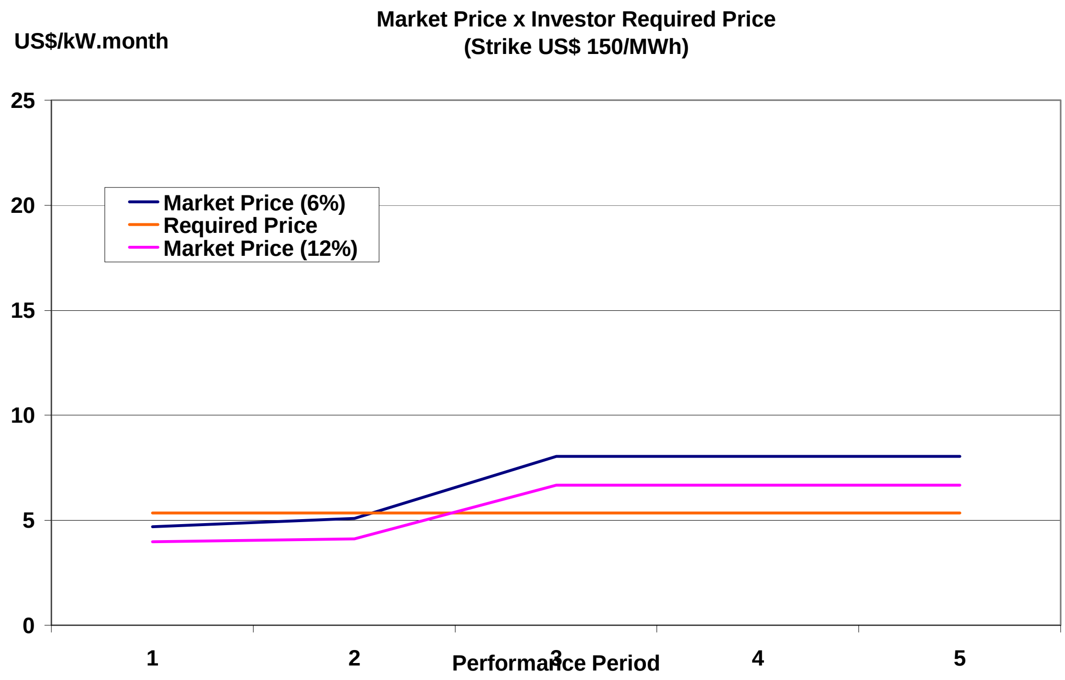


Figure 4.9 – Market Price x Investor Required Price – Strike – US150/MWh

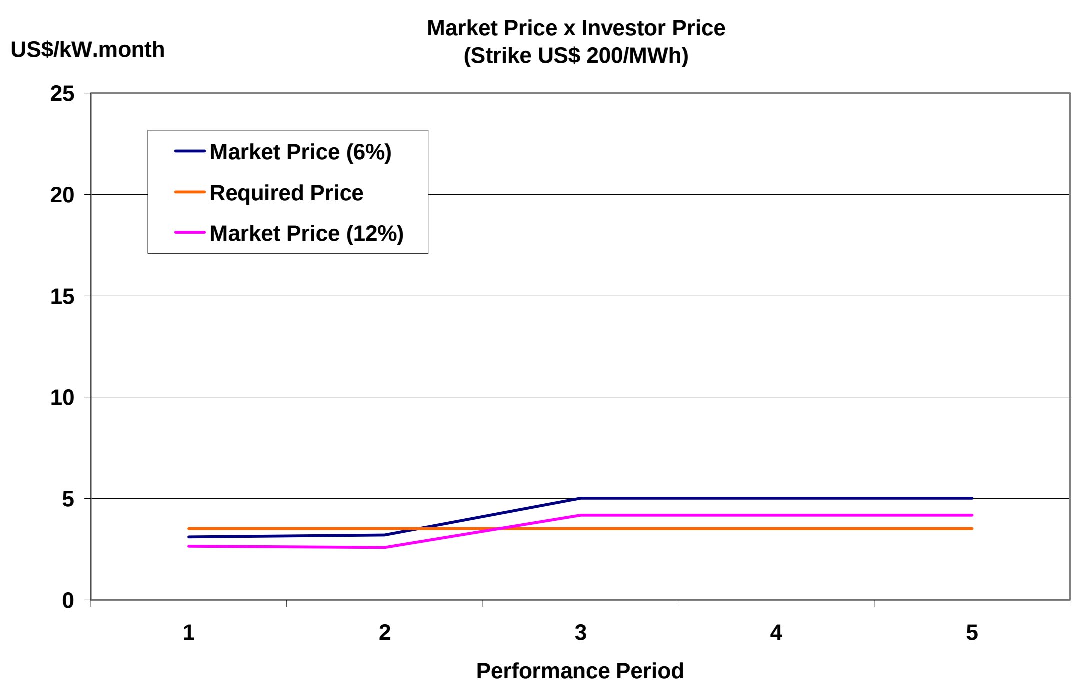


Figure 4.10 – Market Premium x Investor Required Price – Strike – US200/MWh

4.2. PORTFOLIO OPTIMIZATION

In this section we analyze how attractive is to invest on the power plant whose data was presented in Table 4.1 together with the alternatives of commercializing its energy – signing bilateral contracts, selling firm energy options or directly selling energy in the spot market, in terms of profit maximization and risk hedging.

The criteria for optimization is to maximize project discounted net revenue, at a discount rate of 12%, subjected to risk constraints. Risk constraints are of the same kind as the ones specified in Section 3. Here again, a constraint is imposed in the optimization so that maximum amount of total contracting (bilateral contracts plus options) is less than or equal to the plant available capacity. This implies, among other things, that in order to sign a bilateral contract or sell an energy option the agent has to build the plant.

The period of analysis is from January 2003 to December 2029. Plant possible construction date is January 2003. If it is built it will start to operate on January 2005 and as its lifetime is 25 years, the retirement date will be December 2029. To analyze plant energy commercialization strategies we will consider a strip of five energy options, to cover plant lifetime, whose first acquisition period starts on from January 2003. The candidate bilateral contract also covers plant lifetime - from January 2005 to December 2029.

In the first kind of evaluation we determine at which contract price it is advantageous to build the plant and sell its energy through bilateral contract instead of selling directly in the spot market.

Without imposing risk constraints, the best decision at a contract price of US$28/MWh is to build the plant and sell all its energy in the spot market. Figure 4.11 shows for this case the distribution of plant discounted net revenue. Its expected value is US$ 27 MM but it can go from –US$ 208 to US$ 586 MM. The expected value is much lower than for the existing plants (see Section 3), because here it is included the investment cost. Figure 4.12 shows the distribution of internal rate of return whose expect value is 15 % but can be as low as 5.26%, depending of the hydrological scenario. Its standard deviation is σ = 9.1 % and Sharp index, at a 6% risk free interest rate of return, is S = (15 – 6)/ 9.1 = 0.98. The Sharp index should be interpreted with caution here due to the specific nature of investments in power plants with lifetime of 25 years in comparison with the liquidity of investments in the stock market. Figure 4.13 shows the minimum and maximum yearly-accumulated net revenue at a VaR level of 95 % from 2003 to 2029. For the years of 2003 and 2004 the downsides of the yearly-accumulated net revenues are due to disbursement associated to plant investment costs and the fact that it only starts to sell energy in the spot market in 2005. From then one they are associated to low spot prices scenarios when plant revenues are insufficient to cover its fixed operating cost.

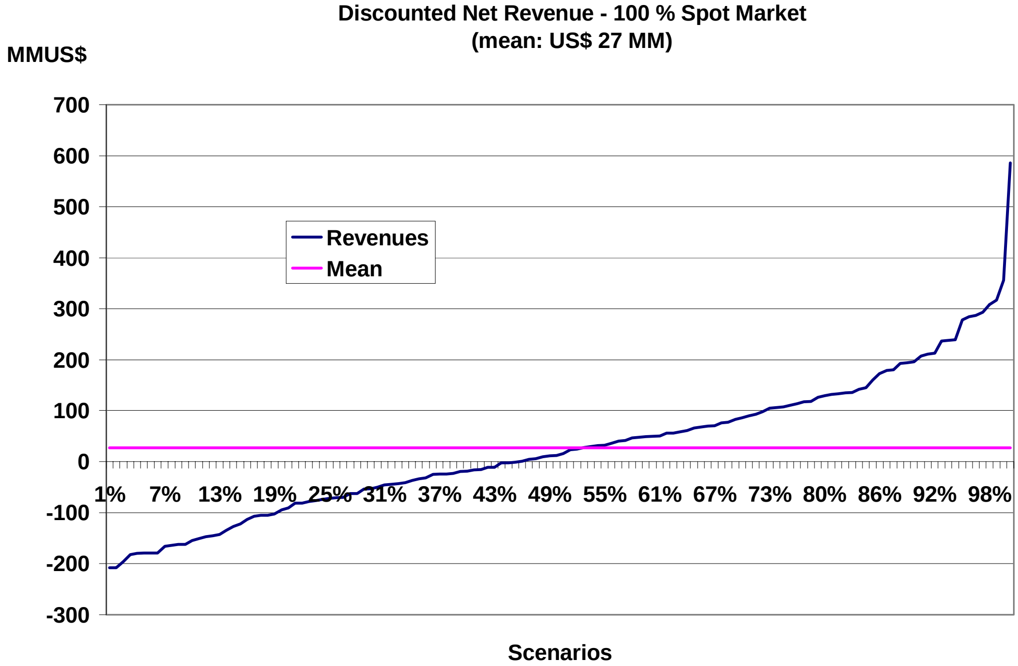


Figure 4.11 – Plant Discount Net Revenue – 100 % Spot

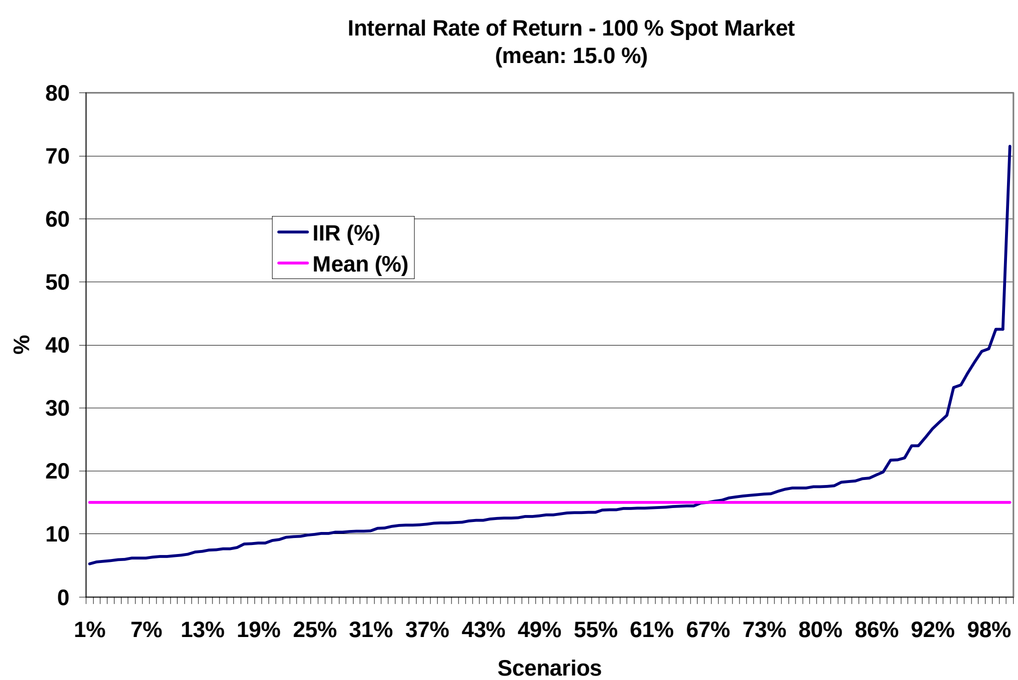


Figure 4.12 – Investment IIR – 100 % Spot

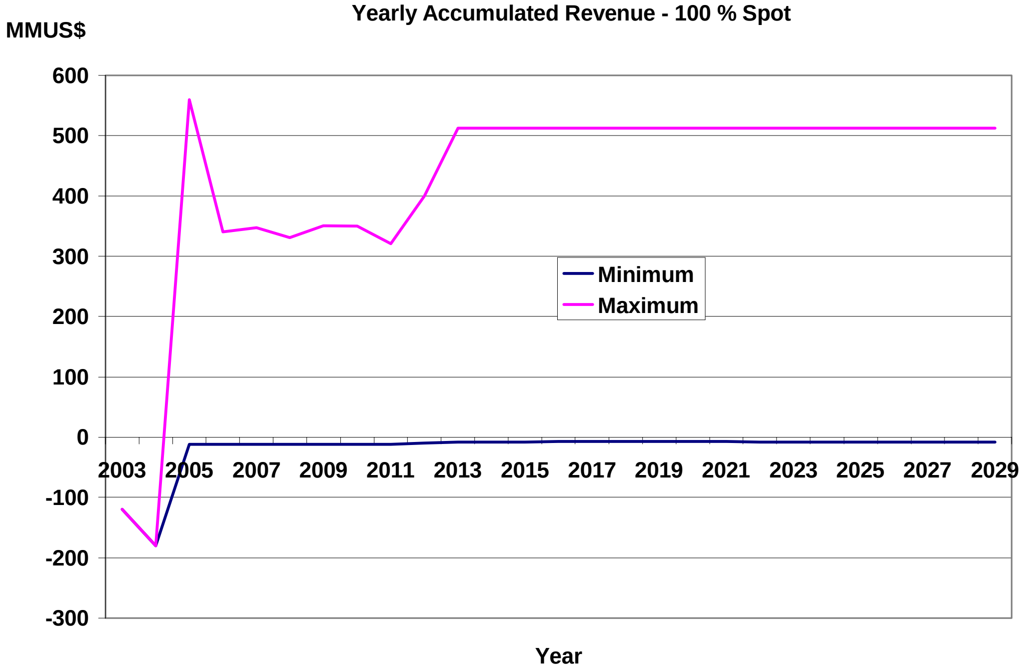


Figure 4.13 – Minimum and Maximum Accumulated Net Revenues – 100 % Spot

Next a risk constraint is imposed requiring that from the year 2005 and on yearly accumulated net revenue should be positive at a 95% VaR level. As result the best decision is to sign a bilateral contract in the amount of 21.3% of plant available capacity and leave the remaining capacity to sell energy in the spot market. The expected value of plant discounted net revenue then dropped to US$ 22 MM, the expected value of the internal rate of return is now 14.3 % and the Sharp index increased to 1.25 due to the decreasing of the internal rate of return standard deviation. Contract at a price US$28/MWh is not as profitable as the spot market but is attractive for hedging against low spot price scenarios.

Now besides bilateral contracts let us consider the possibility of selling energy options. Here we consider first option prices computed at 12 % discount rate. Energy options have a special attractiveness in this case because they provide a revenue before plant starts to operate. For instance, the US30/MWh strike price energy option with price of US$8.84/kW.month in the first acquisition period (see Table 2.2) provides an yearly revenue of US$53 MM (8.84x500000x12) during this period.

For a contract price at US$ 28/MWh and no risk constraints the best decision is to sell energy options with strike of US$200/MWh, up to 100% of plant capacity. Figure 4.14 shows the distribution of plant discounted net revenue for this case and Figure 4.15 the distribution of the internal rate of return. The expected value of the discounted net revenue is close to the case where the plant is 100 % in the spot but its upsides and downsides are smaller. The expected value of the internal rate of return is also slightly less (from 15 % to 14.4 %) and the Sharp index is 1.33 which is higher than when the plant is 100 % in the spot market.

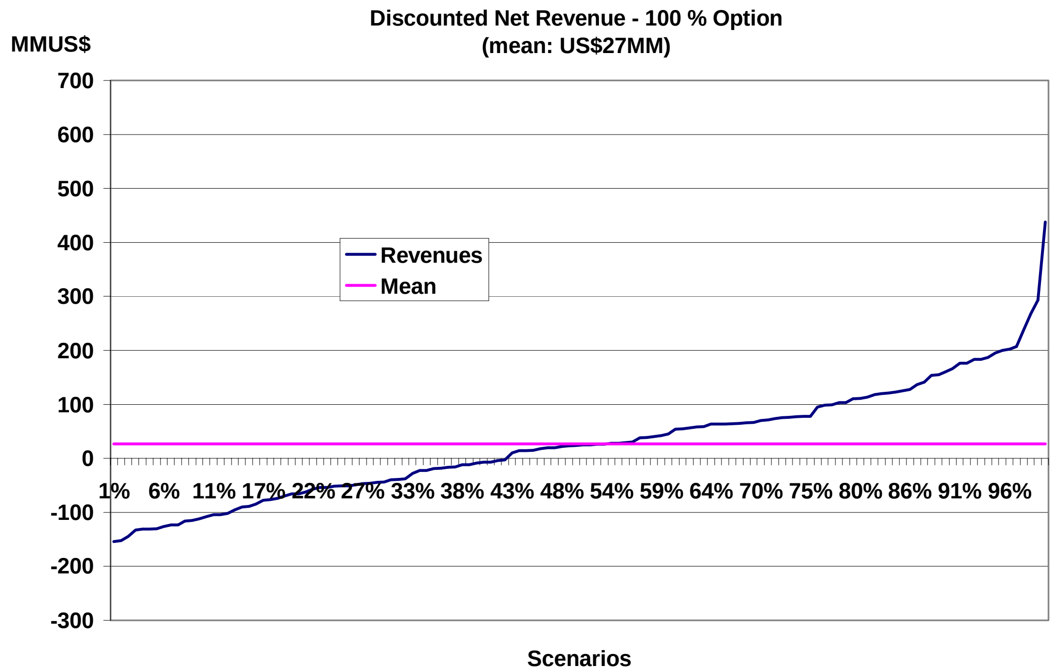


Figure 4.14 – Plant Discounted Net Revenue – 100 % Option

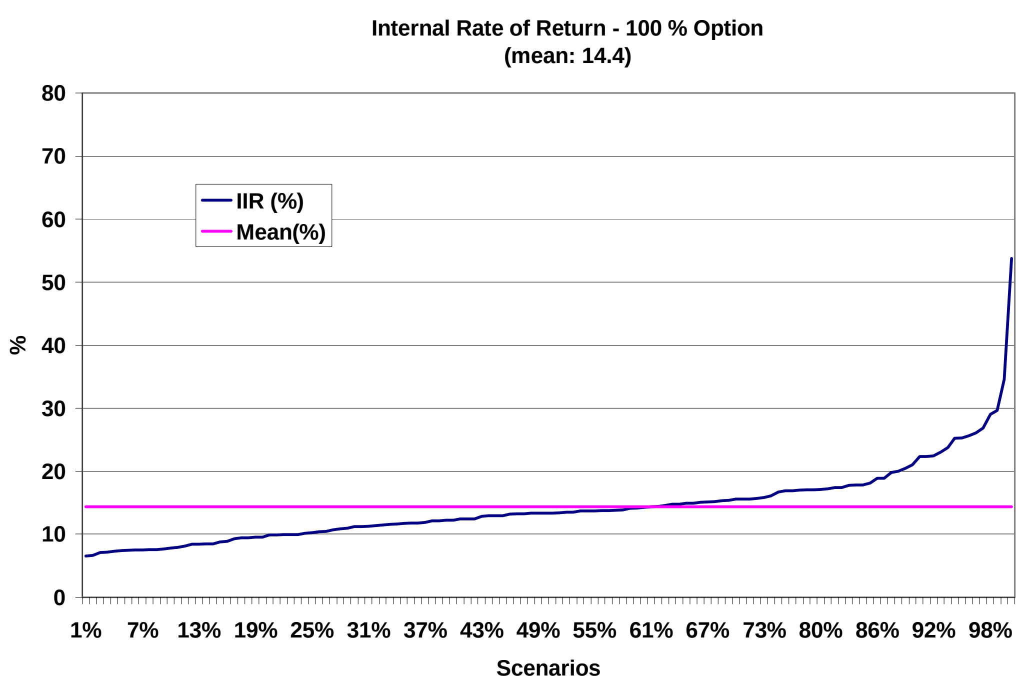


Figure 4.15 – Investment IIR – 100 % Option

Figure 4.16 shows the yearly-accumulated net revenues at a 95 % VaR level from 2003 to 2009 where it can be observed the impact of invest cost disbursements in the years of 2003 and 2004. The downside associated to these years are not as big as before due to the payment of option price in the first acquisition period – for instance in 2004 it decreased from US$180 to US$ 164 MM.

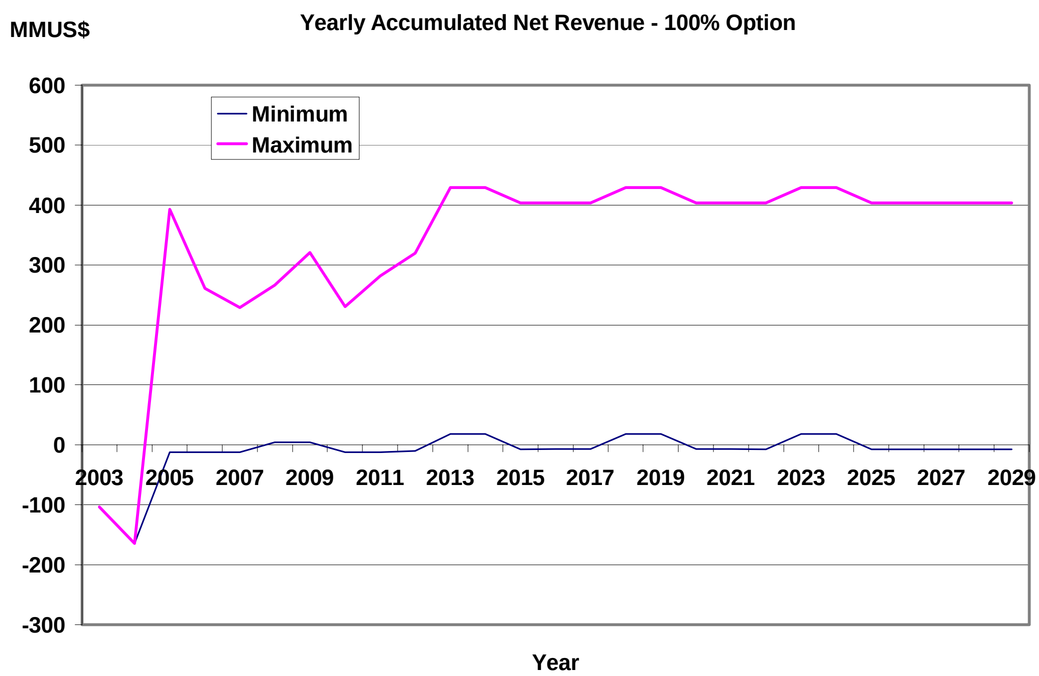


Figure 4.16 – Minimum and Maximum Accumulated Net Revenues – 100% Option

Next risk constraints are imposed such that in the year of 2003 and 2004 when the plant is in construction, yearly-accumulated net revenue should be greater than –US$ 150 MM and when it starts to operate it should be positive at a 95 % VaR level. The best decision now is to sign a contract at a level corresponding to 21.3 % of plant available capacity and sell two energy options - one with strike price US$50/MWh corresponding to 58 % of plant available capacity and the other with strike US$200/MWh corresponding to 20.6 % of plant available capacity. Figure 4.17 shows the distribution of plant discounted net revenue for this case and Figure 4.18 the distribution of the internal rate of return. The expected value of the discounted net revenue dropped to US$ 22MM and of the internal rate of return decreased to 13.8%. The Sharp index increased to 3.54 due to the decreasing of the internal rate of return volatility.

Figure 4.19 shows the minimum and maximum yearly-accumulated net revenue from 2003 to 2029, which shows the decreasing of the downside risk.

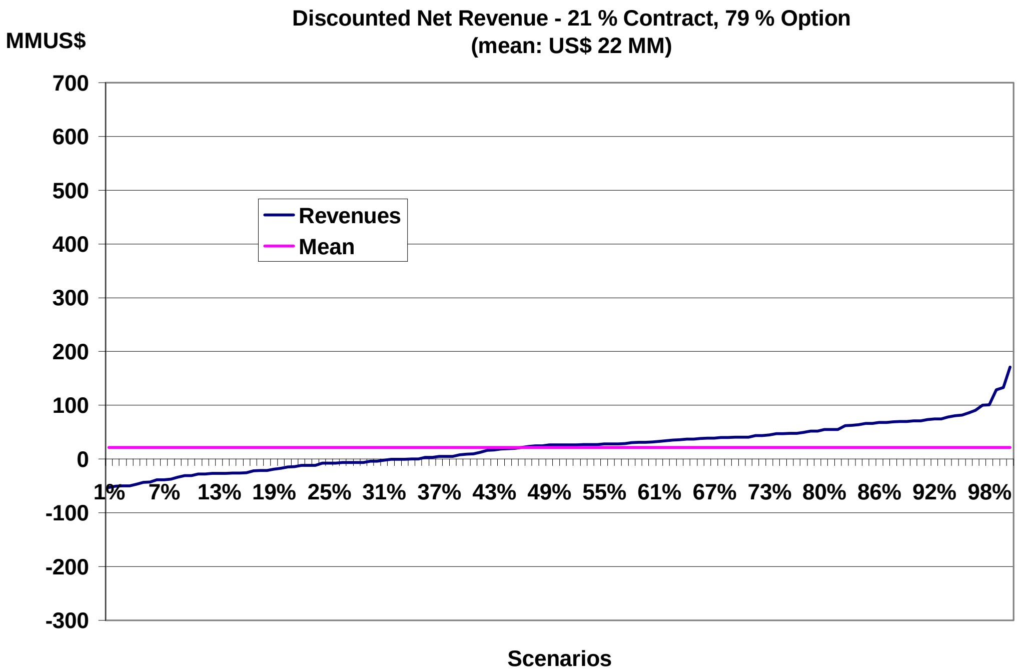


Figure 4.17 – Plant Discounted Net Revenue – 21 % Contract, 79 % Option

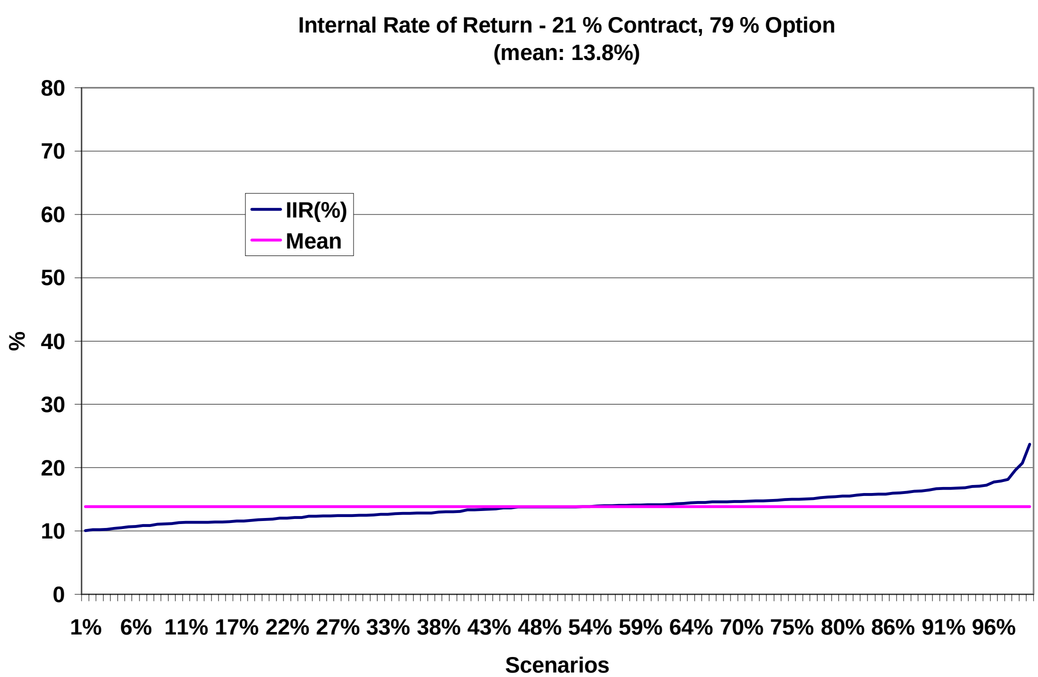


Figure 4.18 – Investment IRR – 21 % Contract, 79 % Option

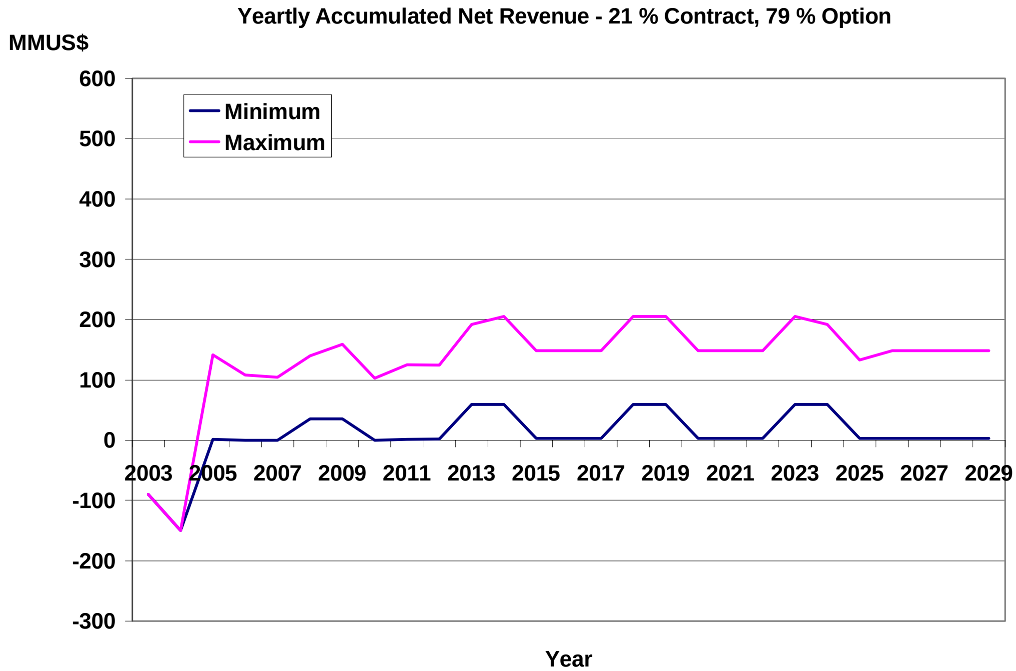


Figure 4.19 – Yearly Minimum and Maximum Net Revenue - – 21 % Contract, 79 % Option

At a price of US29/MWh the best decision is to sell 100 % of plant energy though bilateral contract with or without nonnegative risk constraints from 2005 to 2029. The expected value of the internal rate of return in this case is 14.5% and the Sharp index is high (17.0) due its low volatility. But if some limits on the net revenue downside is imposed for the years of 2003 and 2004 part of the plant should be committed to firm energy options to guarantee some revenues on those years.

Similar computations were carried out with options computed at a 6% discount rate. Table 4.1 presents a summary of the results of this section.

Contract Price (US$/MWh)	Option Price Discount Rate (%)	Risk Const. (Yes/No)	Bilateral Contract (%)	Option (Strike) (%)	Spot (%)	Discounted Net Revenue Expected Value (MMUS$)	IIR (%)
28	NA (*)	No	0%	Forbidden	100	26.7	15.0
28	NA (*)	Yes (**)	21.3	Forbidden	78.7	22.4	14.3
28	12	No	0	100 (US$200/MWh)	0	26.7	14.4
28	12	Yes (***)	21.3	58.1 (US$50/MWh) 20.6 (US$200/MWh)	0	22.0	13.8
29	12	Yes (**)	100	0	0	33.0	14.5
29	12	Yes (***)	43.4	56.6 (US$50/MWh)	0	29.5	14,3
30	6	No	0	100 (US$30/MWh)	0	84.0	17.5
30	6	Yes (**)	18.6	81.4 (US$30/MWh)	0	79.9	17.2
31	6	Yes (**)	100	0	0	86.0	17.1

(*) Not Applicable

(**) Risk Constraint: At 95 % VaR level, yearly-accumulated net revenue from 2005 and on should be positive

(***) Risk Constraint: At 95 % VaR level, yearly losses should be no great than US$150 MM 2003 and 2004, and yearly-accumulated net revenue should be positive in the remaining years

Table 4.1 – Trade-off – Bilateral Contracts, Energy Options and Spot

To summarize the results of portfolio optimization:

1. Trade-off between bilateral contracts and spot:

    - At a contract price of US$28/MWh and no risk constraints the best decision is to build the plant and sell all its energy in the spot, whereas if risk constraints are imposed after plant start operation, the best decision is to sell part of its energy through bilateral contracts.

2. Trade-off among bilateral contract, energy option with price computed based on 12 % discount rate and spot:
    - At a contract price of US$28/MWh and no risk constraints the best decision is to sell 100 % of plant available capacity in energy options, whereas if risk constraints are imposed after plant starting operation, the best decision is to sell part of its energy through bilateral contract and the remaining in energy options;
    - At a contract price of US$29/MWh and some risk constraints imposed after plant starting operation the best decision is to sell all plant energy through bilateral contract. But if minimum revenue is imposed during plant construction the best decision is to sell part of its capacity in energy options and sign a bilateral contract in the amount corresponding to the remaining capacity.
3. Trade-off among bilateral contract, energy option with price computed based on a 6 % discount rate and spot:
    - At a contract price of US$30/MWh and no risk constraints the best decision is to sell 100 % of plant available capacity in energy options, whereas if risk constraints are imposed after plant starting operation, the best decision is to sell part of its energy through bilateral contract and the remaining in energy options.
    - At a contract price of US$31/MWh and some risk constraints imposed after plant starting operation the best decision is to sell all plant energy through bilateral contracts.

5. CONCLUSIONS

The following conclusions can be drawn from the results presented in the previous sections:

- Firm energy options combined with future contracts may provide interesting risk hedging instruments both for existing and new generators
- Based on the simulations, the desired investor option premium based on a required internal rate of return was compatible with the estimated option market price
- By selling firm energy options investor offsets downside risk associated to low spot price scenarios as their prices may cover a great amount of plant fixed costs. Also, the revenue during the construction phase, originated from selling energy option is an important source of income to finance plant investments
- On the other hand, by selling option generators are giving away revenue upsides brought by high spot prices
- The amount of risk hedging and lost upsides depends on option strike prices and the mix proportion among option, futures and spot
- Most appropriate strike price and the mix proportion under investor point of view depends on his risk /return perspective

0 APPENDIX VII - OPTFIMIZATION OF PHYSICAL AND FINANCIAL ASSETS: OPTFOLIO

5.1. INTRODUCTION

OPTFOLIO is a decision support tool for electric energy portfolio management, including physical assets such as generating plants, international interconnections, as well as financial assets such as bilateral contracts and derivative instruments.

The model addresses short-, mid- and long-term decisions such as investment in new equipment, selection of contract mix and purchase of hedging instruments, taking into account uncertainties in future prices, system supply conditions etc. The objective is to optimize the company cash flow taking into account future uncertainties and risk constraints.

Model input data:

- Spot price scenarios
- Existing own generation assets and energy contracts with their associated costs
- Candidate set for plants to be built or purchased with their investment cost or price and operating costs
- Scenarios for electricity generation for existing and new plants
- Candidate set for new financial instruments (contracts and options)
- Native load (for retail companies)
- Risk constraints in terms of utility functions or lower bounds for accumulated net revenue in specified time periods
- Investment budget constraints
- Constraints expressing that financial instrument should be backed by plant available capacity
- Contracting and self-dealing constraints

Output:

- Optimal decision schedule in terms of the sequence of generation plant to be build and of purchasing / selling of financial instruments
- Cash flow distribution
- Accumulated net revenue for the best and worst scenarios
- Internal Rate of Return (IRR) associated to each investment and the global IRR associated to the optimal portfolio
- Risk statistics (certainty equivalent, VaR, "downside risk", etc.) associated to the cash flow.

- Time series graphs associated to several variables such as power generation, spot prices, spot market transactions, energy associated to the financial instruments, net revenue, etc.

5.2. MATHEMATICAL FORMULATION.

5.2.1. INPUT DATA

A large part of the OPTFOLIO input data are hidrological scenario dependent produced by a structural model of production costing.

a) Spot Prices

$$\{ \pi^{d}_{tsh} , t = 1, ..., T; s = 1, ..., S; h = 1,\dots, Nnc\} \quad (7.1)$$

where:

t = stages (T number of stages)

s = scenarios (S number of scenarios)

h = load blocks (Nnc number of load blocks)

π^{d}_{tsh} = spot price for stage t, scenario s, load block h ($/MWh)

b) load block duration

$\{duraci_{th} , t = 1, \dots, T, h = 1, \dots, Nnc\}$

where:

$duraci_{th}$ = time length of load block h in stage t

c) Existing Plants

c.1) Installed capacity

$\{potue_{ue}, u = 1, Nue\}$

where:

ue = existing plant (Nue = number of existing plants).

$potue_{ue}$ = installed capacity of the existing plant ue (MW).

c.2) Available capacity

$\{avpotue_{uet}, ue = 1,\dots, Nue, t = 1, \dots, T\}$

where:

$avpotue_{uet}$ = available capacity of existing plant ue in the stage t.

c.3) Fixed cost

$\{cfixue_{uet}, ue = 1,\dots, Nue, t = 1, \dots, T \}$

where:

$cfixue_{uet}$ = fixed cost associated to the existing plant ue in the stage t (\$/kW).

c.4) Generation

$\{gfue_{uetsh}$, ue = 1,…, Nue, t = 1, …, T, s = 1,…, S, h =1,…, Nnc$\}$

where:

$gfue_{uetsh}$ = physical generation of the existing plant ue in the stage t, scenario s, load block h (GWh).

c.5) Total generation variable cost

$\{cgue_{uets}$, ue = 1,…, Nue, t = 1, …, T, s = 1,…, S$\}$

where:

$cgue_{uets}$ = total generation variable cost of the existing plant belonging to the utility ue in the stage t, scenario s (k\$).

d) candidate plants

d.1) installed capacity

$\{potuc_{uc}$, uc = 1, .., Nuc$\}$

where:

uc = candidate plant (Nuc = number of candidate plants)

$potuc_{uc}$ = installed capacity of the candidate plant uc (MW)

d.2) Alternative dates for entrance in operation

$\{dguc_{ucjduc}$, uc = 1,…, Nuc, jduc= 1,..., Nduc(uc)$\}$

where:

jduc = indexes for entrance in operation dates of the candidate plant uc (Nduc(uc) = total number of possible entrance in operation dates of the candidate plant uc)

$dguc_{ucjduc}$ = entrance in operation date of the candidate plant uc.

d.3) Investment Cost

$\{cinvuc_{uc}$, uc = 1, …, Nuc$\}$

where:

$cinvuc_{uc}$ = investment cost of the candidate plant uc (k\$).

d.4) Available capacity

$\{avpotuc_{ucjduct}$, uc = 1,…, Nuc, jduc= 1,..., Nduc(uc), t = 1, …, T$\}$

where:

$avpotuc_{ucjduct}$ = available capacity of candidate plant uc, entrance in operation date jduc, in the stage t

d.5) Investment payments

$\{dcinvuc_{ucjduct}$, uc = 1,…, Nuc, jduc = 1, ..., Nduc(uc), t = 1, ..., T$\}$

where:

$dcinvuc_{ucjduct}$ = Investment payments associated to the candidate plant uc, entrance in operation date jduc, in the stage t (k$).

Investment payments can be supplied by the user or calculated by the program based on plant investment cost, disbursements chronogram, loan period, interest rates and amortization scheme associated to the project finance

d.6) Fixed Cost

$\{cfixuc_{ucjduct}$, uc = 1,…, Nuc, jduc = 1, ..., Nduc(uc), t = 1, …, T $\}$

where:

$cfixuc_{ucjduct}$ = fixed cost associated to the candidate plant uc, entrance in operation date jduc, in the stage t ($/kW).

d.7) Generation

$\{gfuc_{ucjductsh}$, uc = 1,…, Nuc, jduc=1,..., Nduc(uc), t = 1, …, T, s = 1,…, S, h =1,…, Nnc$\}$

where:

$gfuc_{ucjductsh}$ = physical generation of the candidate plant uc, entrance in operation date jduc, in the stage t, scenario s, load block h (GWh).

d.8) Total generation variable cost

$\{cguc_{ucjducts}$, uc = 1,…, Nuc, jduc=1,..., Nduc(uc), t = 1, …, T, s = 1,…, S$\}$

where:

$cguc_{ucjducts}$ = total generation variable cost of the candidate plant uc, entrance in operation date jduc, stage t, scenario s (k$)

e) Load Data

e.1) Load projected in the Mw average (captive market)

$\{dmca_{icatsh}$, ica = 1,..., Nca, t = 1,…, T, h = 1,…, Nnc$\}$

where:

ica = indexes the captive consumer class (Nca = number of captive consumers classes).

$dmca_{icatsh}$ = energy load in MW average of the consumer class ica, in the stage t, load block h (GWh).

e.2) Associated power

$\{potca_{icat}$, ica = 1,..., Nca, t = 1,…, T$\}$

where:

$potca_{icat}$ = power associated to the load of the consumer class ica, in the stage t (MW).

e.3) Supplying costs

$\{cdca_{icat}$, ica = 1,..., Nca, t = 1,…, T$\}$

where:

$cdca_{icat}$ = load supplying cost for consumer class ica in the stage t ($/kW).

e.4) Fixed payments

$\{pgfca_{icat}$, ica = 1,..., Nca, t = 1,…, T$\}$

where:

$pgfca_{icat}$ = payment per load power of the consumer class ica in the stage t ($/kW).

e.5) Variable tariff

$\{trvca_{icath}$, ica = 1,..., Nca, t = 1,…, T,h=1,..., Nnc $\}$

where:

$trvca_{icath}$ = load energy tariff of the consumer class ica, in the stage t and load block h ($/MWh).

f) Existing Contracts Data

f.1) Energy in MWaverage

$\{ecem_{iceth}$, ice = 1, …, Nce, t = 1, …, T, h = 1, …, Nnc$\}$

where:

ice = indexes existing contracts (Nce = number of existing contracts)

$ecem_{icet}$ = energy specified in MWaverage of the existing contract ice in the stage t, load block h (average MW).

By sign convention, if it is a purchase contract $ecem_{icet} \geq 0$, otherwise $ecem_{icet} < 0$

f.2) Variable tariff

$\{trvce_{iceth}$, ice = 1,..., Nce, t = 1,…, T,h=1,..., Nnc $\}$

where:

$trvce_{iceth}$ = energy tariff of the existing contract ice, in the stage t and load block h ($/MWh).

f.3) Associated power

$\{potce_{icet}$, ice = 1,..., Nce, t = 1,…, T$\}$

where:

$potce_{icet}$ = power associated to the existing contract ice, in the stage t (MW).

By sign convention, if it is a purchase contract $potce_{icet} \geq 0$, otherwise $potce_{icet} < 0$.

f.4) Fixed payments

$\{pgfce_{icet}$, ice = 1,..., Nce, t = 1,…, T$\}$

where:

$pgfce_{icet}$ = payment per contract power associated to the existing contract ice in the stage t ($/kW).

g) Candidate Contracts Data

g.1) Energy in MWaverage

$\{eccm_{iccth}$, icc = 1, …, Ncc, t = 1, …, T, h = 1,…, Nnc$\}$

where:

icc = indexes candidate contract (Ncc = number of candidate contracts)

$eccm_{ith}$ = energy in MWaverage of the candidate contract icc in the stage t load block h (MWaverage)

By sign convention, if it is a purchase contract $eccm_{ith} \geq 0$, otherwise $eccm_{ith} < 0$

g.2) Variable tariff

$\{trvcc_{iccth}$, icc = 1,..., Ncc, t = 1,…, T, h=1,..., Nnc $\}$

where:

$trvcc_{iccth}$ = energy tariff of the candidate contract icc, in the stage t and load block h ($/MWh).

This data can be supplied by the user or calculated by the program using the spot prices scenarios and future contracts pricing theory.

g.3) Associated power

$\{potcc_{icct}$, icc = 1,..., Ncc, t = 1,…, T$\}$

where

$potcc_{icet}$ = power associated to the candidate contract icc, in the stage t (MW).

By sign convention, if it is a purchase contract $potcc_{icet} \geq 0$, otherwise $potcc_{icet} < 0$.

g.4) Fixed payments

{$pgfcc_{icct}$, icc = 1,..., Ncc, t = 1,…, T}

where:

$pgfcc_{icct}$ = payment per contract power associated to the candidate contract icc in the stage t ($/kW).

h) Options Data

h.1) Energy in MWaverage

{$eopm_{iopth}$, iop = 1, …, Nop, t = 1, …, T, h = 1,…, Nnc}

where:

iop = indexes candidate option contract (Nop = number of candidate option contracts)

$eopm_{iopth}$ = energy in the MWaverage of the option iop in the stage t load block h (MWaverage).

The option can be a call or a put and the commercial transaction can be of purchasing or selling the option. For example, a distributor can buy a call or sell a put and a generator can sell a call or buy a put.

By sign convention, if it is a call option and the transaction of buying it $eopm_{iopth} \geq 0$, if it is a call and a selling transaction $eopm_{iopth} < 0$, if it is a put option and the transaction of buying it $eopm_{iopth} < 0$ and, if it is a put and a selling transaction $eopm_{iopth} \geq 0$.

h.2) Strike price

{$kop_{iopikop}$, iop = 1, …, Nop, ikop = 1, …, Nkop(iop)}

where:

ikop = indexes strike prices of the option (Nkop(iop) = number of strike prices)

$kop_{iopikop}$ = strike price ikop of the option iop ($/MWh)

h.3) Option premium

{$poptot_{ioptikop}$, iop = 1,..., Nop, t = 1, …, T, ikop = 1, …, Nkop(iop)}

where:

$poptot_{ioptikop}$ = total prize of the option iop, stage t and strike price ikop

This data can be supplied by the user or calculated by the program using the spot prices scenarios and option pricing theory

i) ***VaR level Data***

θ_{VaR}

where:

θ_{VaR} = VaR level (%) associated to the output reports and risk constraints.

j) ***Risk Constraints Data***

j.1) Intervals for accumulated net revenues for risk constraints

$\{intrr_\tau , \tau = 1,\ldots, Naprec\}$

where:

τ = indexes time intervals for accumulated net revenue (Naprec = number of intervals for net revenues)

$intrr_\tau$ = time interval for accumulated net revenue

j.2) Minimum net revenues for risk constraint

$\{recmin_\tau , \tau = 1,\ldots, Naprec\}$

$recmin_\tau$ = minimum accumulated net revenue in all scenarios or at VaR level, associated to interval τ.

k) ***Investment Constraint Data***

k.1) Intervals for budget constraints

$\{intro_\tau , \tau = 1,\ldots, Ninv\}$

where:

τ = indexes time interval for accumulated investment costs (Ninv = number of intervals for accumulated investment costs)

$intro_\tau$ = time interval for accumulated investment budget constraint

k.2) Maximum investment expenditure

$\{kimax_\tau , \tau = 1,\ldots, Ninv\}$

where:

$kimax_\tau$ = maximum investment expenditure in time interval τ.

l) ***Associated Projects Data***

$\{aspr_{iapr} , iapr = 1, ..., Napr\}$

where:

iapr = indexes groups of associated projects (Napr = total number of groups of associated projects)

$aspr_{iapr}$ = group of projects (plants, contracts and options) associated to the association iapr.

m) Project constraints

m.1) Project groups

$\{restpr_{irp}, irp = 1, ..., Nrp\}$

where:

irp = indexes project constraints (Nrp = total number of project constraints)

$restpr_{irc}$ = group of candidate plants uc, candidate contracts icc and candidate options iop associated to the project constraint irp.

m.2) Constraint coefficient – candidate plants

$\{coefpru_{irpuc}, irp = 1, ..., Nrp, uc \varepsilon restpr_{irp}\}$

where:

$coefpru_{irpuc}$ = coefficient of candidate plant uc in project constraint irp

m.3) Constraint coefficient – candidate contracts

$\{coefprc_{irpicc}, irp = 1, ..., Nrp, icc \varepsilon restpr_{irp}\}$

where:

$coefprc_{irpuc}$ = coefficient of candidate contract icc in project constraint irp

m.4) Constraint coefficient – candidate options

$\{coefpro_{irpiop}, irp = 1, ..., Nrp, iop \varepsilon restpr_{irp}\}$

where:

$coefpro_{irpuc}$ = coefficient of candidate option iop in project constraint irp

m.5) Constraint RHS

$\{rhsrp_{irpth}, irp = 1, ..., Nrp, t = 1,\ldots, T, h=1,..., Nnc\}$

where:

$rhsrp_{ircth}$ = right side of the project constraint irp in the stage t, load block h (MWaverage)

m.6) Indicator of inequality

$\{idrp_{irc}, irp = 1, ..., Nrp\}$

where:

$idrp_{irp}$ = inequality indicator of the contract constraint irp:

$idrp_{irc}$ = 0: " ≤" ;$idrp_{irc}$ = 1: "≥"; $idrp_{irc}$ = 2: "=".

n) Annual Discount Rate

r

where:

r = annual discount rate

o) Utility Function

The utility function is defined as a piece wise linear function:

$$U(vp) = \text{Max } \alpha$$
$$\text{s.a.}$$
$$\alpha \leq a_{iu} + b_{iu}vp \text{ , } i = 1,\ldots, Nu$$

where:

vp = discounted net revenue

iu = indexes number of segments of the utility function (Nu = total number of segments)

a_{iu}, b_{iu} = independent and linear term of the i-th segment of the utility function

5.2.2. VARIABLES

a) Decision on investing on candidate plants

{$xbuc_{ucjduc}$, uc = 1, …, Nuc, jduc=1,..., Nduc(uc)}

where:

$xbuc_{ucjduc}$ = binary variable associated to the investment decision in candidate plant project uc, entrance date jduc.

$xbuc_{ucjduc}$ = 1, decides to invest in the plant uc entrance date jduc, otherwise $xbuc_{ucjduc}$ = 0

b) Participation amount in candidate plants

{xuc_{ucjduc}, uc = 1, …, Nuc, jduc=1,..., Nduc(u)}

where:

xuc_{ucjduc} = participation amount associated to the candidate plant project uc entrance date jduc (%).

c) Contracting amount for candidate contract

{xcc_{icc} , icc = 1, .., Ncc}

where:

xcc_{icc} = contracting amount of candidate contract icc (%)

d) Option contracting amount

$\{xop_{iopikop}$, iop = 1, .., Nop, ikop = Nkop(iop)$\}$

where:

$xop_{iopikop}$ = Contracting amount of option iop with strike price ikop (%)

e) Spot purchasing and sales

$\{cpvdsp_{tsh}$, t = 1, …, T, s = 1,…, S, h = 1,…, Nnc$\}$

where:

$cpvdsp_{tsh}$ = purchase / sale in spot in the stage t, scenario s and load block h (GWh)

By sign convention, $cpvdsp_{tsh} \geq 0$ for purchase and $cpvdsp_{tsh} \leq 0$ for sale

f) Net revenue

$\{rcliq_{ts}$, t = 1, …, T, s = 1, …, S$\}$

where:

$recliq_{ts}$ = net revenue in stage t, scenario s (KR$)

g) Net revenue present value

$\{vp_s$, s = 1, …, S$\}$

where:

vp_s = net revenue present value in the scenario s

h) Utility value

$\{ut_s$, s = 1,…, S$\}$

where:

ut_s = utility value in the scenario s

i) Accumulated net revenue in defined intervals

$\{rcliqap_{\tau ts}$, τ = 1,…, Naprec, t = 1, …, T, s = 1, …, S$\}$

where:

$rcliqap_{\tau ts}$ = accumulated net revenue in time interval τ, stage t and scenario s (k$)

j) Auxiliary binary variables for risk control at VaR level

$\{kvar_s$, s = 1, ...S$\}$

where:

$kvar_s$ = binary variable associated to the scenario s for risk control at VaR level:

$kvar_s = 1 \Rightarrow$ discarded scenario, otherwise it is considered.

5.2.3. CONSTRAINTS

a) Definition of spot purchasing and sales

$$cpvdsp_{tsh} = \sum_{ica} dmca_{icatsh} \frac{duraci_{tih}}{1000.} - \sum_{ue} gfue_{uetsh} - \sum_{uc,jduc} \frac{xuc_{ucjduc}}{100.} gfuc_{ucjductsh} - \sum_{ice} ecem_{iceth} \frac{duraci_{th}}{1000.} - \sum_{icc} \frac{xcc_{icc}}{100.} eccm_{iccth} \frac{duraci_{th}}{1000.} - \sum_{iop,ikop} \frac{xop_{iopikop}}{100.} iexop_{iopikoptsh} \, eopm_{iopth} \frac{duraci_{tih}}{1000.} \qquad (a)$$

t=1,..., T; s = 1,..., S; h = 1,..., Nnc

where:

$iexop_{iopikoptsh}$ = indicator of option exercising for option iop, strike ikop, stage t, scenario s, load block h:

If it is a call, $iexop_{iopikoptsh} = \begin{cases} 1 & \pi^{d}_{tsh} > kop_{iopikop} \\ 0 & \text{otherwise} \end{cases}$

If it is a put, $iexop_{iopikoptsh} = \begin{cases} 1 & \pi^{d}_{tsh} < kop_{iopikop} \\ 0 & \text{otherwise} \end{cases}$

b) Definition of the net revenue

$$recliq_{ts} = \qquad (b)$$

$$\sum_{ica} \left(\left(\sum_{h} trvca_{icath} \, dmca_{icatsh} \frac{duraci_{th}}{1000.} \right) + (pgfca_{icat} - cdca_{icat}) potca_{icat} \right) - \sum_{ue} (cgue_{uets} + cfixue_{uect} potue_{ue}) - \sum_{uc,jduc} \frac{xuc_{ucjduc}}{100.} (dcinvuc_{ucjduct} + cguc_{ucjducts} + cfixuc_{ucjduct} potuc_{uc}) -$$

$$\sum_{ice}((\sum_{h} trvce_{iceth} ecem_{iceth} \frac{duraci_{th}}{1000.}) + pgfce_{icet} potce_{icet}) -$$

$$\sum_{icc} \frac{xcc_{icc}}{100.}((\sum_{h} trvcc_{iccth} eccm_{iccth} \frac{duraci_{th}}{1000.}) + pgfcc_{icct} potcc_{icct}) -$$

$$\sum_{iop,ikop} \frac{xop_{iopikop}}{100.}((\sum_{h} kop_{iopikop} iexop_{iopikoptsh} eopm_{iopth} \frac{duraci_{th}}{1000.}) + poptot_{ioptikop}) -$$

$$\sum_{h} \pi^{d}_{tsh} cpvdsp_{tsh}$$

t = 1,…, T; s = 1,…, S

c) ***Definition of accumulated net revenue in defined intervals***

$$rcliqap_{\tau ts} = \sum_{t \in int\, rr_{\tau}} recliq_{ts} \qquad \text{(c)}$$

τ = 1, ..., Naprec

d) ***Risk constraints***

$$rcliqap_{\tau s} + 10^{20} k\,var_{s} \geq recmin_{\tau} \qquad \text{(d)}$$

τ = 1, ..., Naprec, s = 1,…, S

$$\sum_{s} k\,var_{s} \leq S \frac{\theta_{VaR}}{100.} \qquad \text{(e)}$$

Obs.: The constraint (e) implies that θ_{VaR} is the maximum percentage of scenarios that can be discarded

e) ***Constraints that limit the plant investment to only one date***

$$\sum_{jduc} xbuc_{ucjduc} \leq 1 \qquad \text{(f)}$$

uc = 1, ..., Nuc

$$xuc_{ucjduc} \leq 100 xbuc_{ucjduc} \qquad \text{(g)}$$

uc = 1, ..., Nuc, jduc = 1, ..., Nduc(uc)

f) ***Investment Budget constraints***

$$\sum_{dguc_{ucjduc} \in int\, ro_{\tau}} \frac{xuc_{ucjduc}}{100.} cinvuc_{uc} \leq kin\max_{\tau} \qquad \text{(j)}$$

$\tau = 1,\ldots, Ninv$

g) ***Contracting amount limit***

$xcc_{icc} \le 100.$ (k)

$icc = 1, .., Ncc$

h) ***Option contracting amount limit***

$xop_{iopikop} \le 100.$ (l)

$iop = 1, .., Nop, ikop = 1, ..., Nkop(iop)$

i) ***Associated projects constraints***

$$xuc_{uc_1 jduc_1} = xuc_{uc_2 jduc_2}; xcc_{icc_1} = xcc_{icc_2};$$
$$xuc_{uc_1 jduc_1} = xcc_{icc_1}; xuc_{uc_1 jduc_1} = xop_{iop_1 ikop_1}; \quad (m)$$
$$xop_{iop_1 ikop_1} = xop_{iop_2 ikop_2}$$

$uc_1, uc_2, icc_1, icc_2, iop_1, iop_2 \in aspr_{iapr}.$

$iapr = 1, ..., Napr$

j) ***project constraints***

$$\sum_{\{uc,icc,iop\}\in respr_{irp}} \{ \sum_{jduc\in Nduc(uc)} coefpru_{irpuc} avpotuc_{ucjduct} \frac{xuc_{ucjduc}}{100.} + coefprc_{irpicc} eccm_{iccth} \frac{xcc_{icc}}{100.} + coefpro_{irpiop} eopm_{iopth} \frac{xop_{iop}}{100.} \} \le rhsrp_{irph} \quad (n)$$

$t = 1, \ldots, T, h = 1, \ldots, Nnc, irp = 1, \ldots, Nrp$ s.t. $idrp(irp) = 0$

$$\sum_{\{uc,icc,iop\}\in respr_{irp}} \{ \sum_{jduc\in Nduc(uc)} coefpru_{irpuc} avpotuc_{ucjduct} \frac{xuc_{ucjduc}}{100.} + coefprc_{irpicc} eccm_{iccth} \frac{xcc_{icc}}{100.} + coefpro_{irpiop} eopm_{iopth} \frac{xop_{iop}}{100.} \} \ge rhsrp_{irph} \quad (o)$$

$t = 1, \ldots, T, h = 1, \ldots, Nnc, irp = 1, \ldots, Nrp$ s.t. $idrp(irp) = 1$

$$\sum_{\{uc,icc,iop\}\in respr_{irp}} \{$$

$$\sum_{jduc\in Nduc(uc)} coefpru_{irpuc} avpotuc_{ucjduct} \frac{xuc_{ucjduc}}{100.}$$

$$+ coefprc_{irpicc} eccm_{iccth} \frac{xcc_{icc}}{100.} + coefpro_{irpiop} eopm_{iopth} \frac{xop_{iop}}{100.} \} = rhsrp_{irph} \qquad (p)$$

t = 1, …, T, h = 1, …, Nnc, irp = 1, …, Nrp s.t. idrp(irp) =1

k) ***Definition of the net revenue present value:***

$$vp_s = \sum_t \frac{recliq_{ts}}{(1+r)^t} \qquad (s)$$

s = 1,…, S

l) ***Definition of Utility value***

$$ut_s \le a_i + b_i vp_s \qquad (t)$$

i = 1,…, Nu, s = 1,…, S

5.2.4. OBJECTIVE FUNCTION

a) ***Maximization of the discounted net revenue expected value:***

$$\text{Max} \frac{\sum_s vp_s}{S}$$

b) ***maximization of the utility function expected value***

$$\text{Max} \left\{ \frac{\sum_s ut_s}{S} \right\}$$

c) ***Maximization of the minimum accumulated net revenue in time interval:***

Max y

where:

$y \le rcliqap_{\tau s}$

τ = 1, ..., Naprec, s = 1, ..., S

obs: when this objective function is considered the risk constraint is deactivated.

d) ***Maximization of the minimum accumulated net revenue in time interval at VaR level:***

Max yVaR

where:

$$yVaR \leq rcliqap_{\tau s} + 10^{20} k\,var_s$$

τ = 1, ..., Naprec, s = 1,…, S

$$\sum_s k\,var_s \leq S \frac{\theta_{VaR}}{100.}$$

obs: when this objective function is considered the risk constraint is deactivated.

5.3. INTERNAL RATE OF RETURN

As net revenue stream is scenario dependent, the internal rate of return associated to an investment portfolio of physical and financial assets is also scenario dependent. Let $recliqa_{ias}$ be the accumulated annual revenue in year ia, stage s:

$$recliqa_{ias} = \sum_{t \in year_{ia}} recliq_{ts} \text{ , ia = 1, …, Na}$$

where:

Na = number of years

$recliq_{ts}$ = net revenue in stage t, scenario s as defined in section 2.3.1

$year_{ia}$ = set of stages corresponding to year ia.

The free of tax internal rate of return associated to scenario s, r_s is such that:

$$\sum_{ia=1}^{Na} \frac{1}{(1+r_s)^{ia}} recliqa_{ias} = 0.$$