A probabilistic Approach for Evaluating Alternatives to Reduce Minimum Send Out Rate at LNG Regasification Terminal

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Abstract

This paper presents a multi-scenario stochastic valuation model to select the most attractive Minimum Send Out (MSO) option for an LNG terminal. The model utilizes the Poisson and the exponential distributions to model the number of days the MSO equipment would operate conditional on the probability of securing LNG contract. These distributions feed into a cash flow model that produces an NPV distribution for a particular MSO option. Forward simulations use Crystal Ball with one million scenarios. As an input, the model takes CAPEX and OPEX data provided by the LNG terminal operator and user data including sourcing success and LNG-Gas (e.g. TTF) spread. Optional input may include preferred start up date, installation lead time and permitting. The final result is a set of NPV distributions corresponding to all MSO options which form the basis for comparison / selection of the preferred MSO alternative that has the highest risk-adjusted return. Optionality includes cargo diversion and market flexibility offered by each equipment alternative.

1 Notation, Introduction and Motivation

1.1 Notations and Definitions

- MSO: Minimum send out rate.
- MSORU: MSO reduction unit
- BOG: Boil-off gas refers to the LNG vapors that are produced as a result of heat input and pressure variations that occur within various LNG stages

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- Shippers: Customers of LNG regasification terminals with firm regasification capacity commitments.

1.2 Introduction to Minimum Send Out

Within an LNG regasification terminal, LNG is pumped out from the storage tanks to the BOG re-condenser and then via the send-out pumps to the vaporizers. BOG from the LNG storage tanks is compressed by the BOG compressors into the BOG re-condenser for re-liquefaction, together with the LNG send-out. A **minimum send-out** (MSO) flow rate would be required to re-condense all BOG. The minimum send-out flow rate through an LNG terminal is a function of the amount of LNG storage tanks, the length and diameter of the lines, ship loading/unloading, LNG composition and BOG re-condenser pressure. The amount of BOG generation is determined by the size of LNG storage tanks, length and diameter of the cryogenic lines and circulation between the jetty and LNG storage tanks.

1.3 Business Case

Typical regasification terminal design driven by a throughput philosophy assumes capacity holders have firm LNG supply of a point-to-point type and that Shippers would constantly bring in, regasify and send out certain amount of LNG/gas. For a throughput terminal with a dedicated point-to-point LNG supply the requirement to maintain a minimum flow of LNG is unlikely to be an issue.

However in the recent years we have seen that capacity commitments and LNG supply may not necessarily be guaranteed back to back, thus securing cost-effective long term (LT) LNG supply may become an issue. For instance in 2008 LNG supply was very tight, spot prices skyrocketed to \$ 20+/mmbtu and producers were reluctant to commit long term as they kept flexibility in order to capitalize on price spikes. Some prospective LNG buyers found themselves in a position where they have contracted long term LNG re-gasification capacity at existing/new terminals without firm long term LNG supply agreements. MSO requirement without guaranteed LNG supply creates risk and exposure for the holders of regasification capacity to the spread between local gas prices and LNG spot markets as purchase of LNG on a spot market may be forced upon them to maintain minimum LNG flow at the terminal. For example if the spread between LNG spot price and the local gas market is \$2/mmbtu, then a Shipper who bought a standard cargo on the spot market in order to comply with MSO and sold it in the local gas market would take a loss of approximately \$6 million.

Another issue is the value of flexibility for the holders of LNG regasification capacity (Shippers). Reducing or removing MSO requirement creates additional extrinsic value for the regasification capacity positions because now shippers have an option to send the MSO LNG anywhere any time to the higher value destination (subject of course to the LNG SPA terms and conditions). Shippers would be in a better position to capitalize on short term market opportunities.

There is a number of technical solutions that can reduce/eliminate MSO and are based on installation of additional specific equipment including but not limiting to the following list of alternatives:

- Reliquefaction;
- Co-generation;
- BOG HP compression;
- BOG LP compression;
- Using existing LNG peak shavers;
- Others

These solutions require additional CAPEX and OPEX spending and potentially may need additional permitting. On the other hand, they do offer an opportunity to reduce, or even eliminate MSO. In this paper we will explore some modelling solutions for calculating NPV values that could be used in comparing deferent MSO reduction alternatives.

From shipper's standpoint, MSORU investment has negative cash flow for CAPEX and OPEX and positive cash flow from realized optionality:

1. Extrinsic value of the reduced LNG spot risk (less chances of buying on the spot when the LNG-Gas spread is negative)
2. Diversion option value when LNG spot prices are higher in other markets (like Japan or Spain).

The best alternative is the one that has the highest risk-adjusted NPV, taking into account cost and option value. Key factors of the economic analysis of the alternatives are:

- LNG/Gas prices spread
- CAPEX
- OPEX

CAPEX is provided by the prospective EPC contractor or engineering advisor and most likely would be outside of Shipper's control. LNG/Gas prices are confidential internal views that are produced by the company independently of this decision making process. Which leave us with OPEX as the key random variable to model and estimate. OPEX cash flow for MSORU is driven by the number of days the MSORU is operating because:

$$\begin{aligned} OPEX\ costs\ p.a. &= \{Opex\ cost\ per\ unit\ of\ time\} * \\ &\quad \{Time\ units\ the\ equipment\ operates\ p.a.\}. \end{aligned}$$

where OPEX costs per unit would be provided by EPC contractor and are outside of the Shipper's control. Since MSORU only operates when no LNG flows through the terminal, the amount of time when MSORU is switched on becomes the main variable in modeling OPEX. Thus in this paper we will focus on how to model the number of days when MSORU is on/off as it is the main random variable in the decision making process for the reduction of MSO rate. Hereafter we use days as a time unit. However, any alternative periods could be used.

2 Modeling the Number of Days the Equipment is Operating

The utilization of the equipment depends on two regimes. The first regime is when no LNG forward contract is in place, and therefore the equipment is expected to be turned on most of the year. The second regime is when we have an LNG contract in place and therefore the equipment is turned on less often, because of the flow of LNG from the cargos. The expected number of days where the equipment is on could in theory be estimated using different factors such as market price of LNG, geopolitical causes of LNG interruption, risk of ships sinking or being diverted and our ability to secure LNG cargos arrival to the terminal. However, we are going to adopt a more practical approach for such estimation.

2.1 Period Before Locking-in a Forward Contract

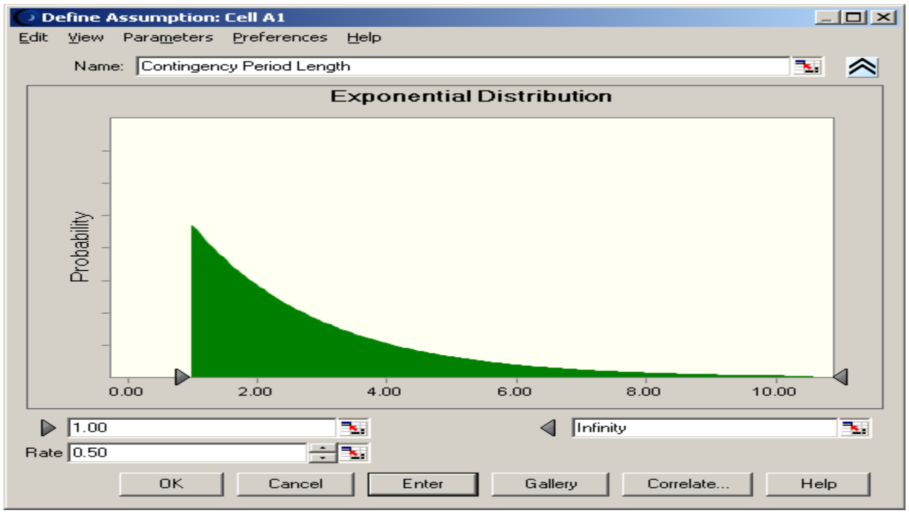
2.1.1 Contingency Period

Let T denote the number of years needed before we can lock-in a forward contract. The period $[0, T]$ is called a contingency period since no forward contract is put in place to hedge the market risk.

T will be modeled as positive random variable following the exponential distribution with a rate of decay λ estimated such that there is 99% chance of locking-in a forward contract in 10 years, i.e. $P[T \leq 10] = 99\%$, see Figure (1). The 10 years horizon is an assumption made by the management which reflects the confidence in locking the forward contract in the future. This assumption can be revised if the effort of the gas sourcing team breeds more optimism in locking in an LNG contract.

2.1.2 Number of Days the equipment is Operating

For each year t in $[0, T]$, let us denote by $N(t)$ the number of days when the equipment is on. We will model $N(t)$ as a positive random variable following Poisson distribution with expected number of days $e(t)$ to be estimated. Poisson is a typical discrete probability distribution that expresses the probability of a number of events occurring in a fixed period of time if these events occur



Name: Contingency Period Length

1.00

Infinity

Rate 0.50

Figure 1: Contingency period modeled as exponential distribution with 99% chance of ending within 10 years horizon

with a known average rate and independently of the time since the last event. Moreover, we have

$$0 \leq N(t) \leq 365$$

It is rather difficult to estimate the average number of days when the unit is switched on. If the cost of sourcing LNG from the spot market is lower than the local gas market price + OPEX + the amortized CAPEX of the equipment, then we are better off sourcing LNG from the spot market and the equipment will be turned off. If the LNG spot market was transparent (exchange for instance), then we should be able to run statistical tests, to estimate the level of LNG spot price that makes the LNG sourcing cost a break even. Then we can estimate the number of days where the prices are below this break even threshold. Since there is no transparent spot market for LNG, we consider the simple case scenario where $e(t)$ is constant, say 180 days per year. This figure is estimated on the basis that there is a $50 - 50$ chance that LNG spot prices are favorable. This is obviously a subjective estimation and could be challenged.

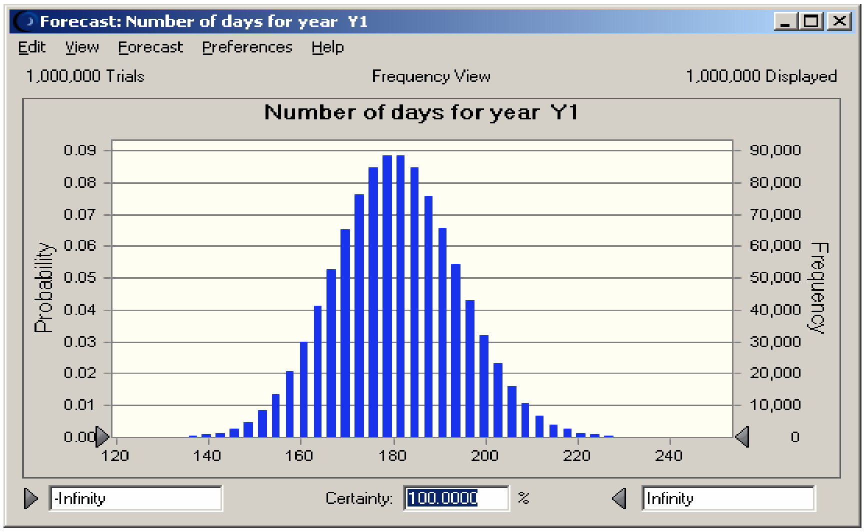
2.2 Period After Locking-in a Forward Contract

At the end of the contingency period, the number of days the unit will be switched on is virtually zero, since a forward contract with physical delivery of LNG will ensure that the 20% minimum send out is guaranteed. However, in order to take into account the credit risk, force majeure, or other interruptibility factors, the end period number of days will be modeled as a Poisson random variable with an expected number of days per year equal to 10 days per year. Each year can have a number of days when the LNG cargos cannot make it to the GATE. During these days, the equipment will be operating to compensate for the lack of LNG injection.

2.3 Distribution of the Number of Days the unit is on for Different Years

The distribution will have two modes. The first mode is during the contingency period, where it is modeled as Poisson (180). The second mode is after the contingency period where it follows Poisson (10).

At the beginning of the contingency period, the first mode is prevailing. As we progress through time, the second mode takes over at a rate prescribed by the exponential decay rate λ of the contingency period T. Figure (2) depicts the probability distribution of the number of days the equipment is switched on during the first year. Using the setup here, there is almost no chance of securing an LNG forward contract during the first year so we are well and truly inside the contingency period, and the distribution is purely Poisson (180).



1,000,000 Trials

1,000,000 Displayed

-Infinity

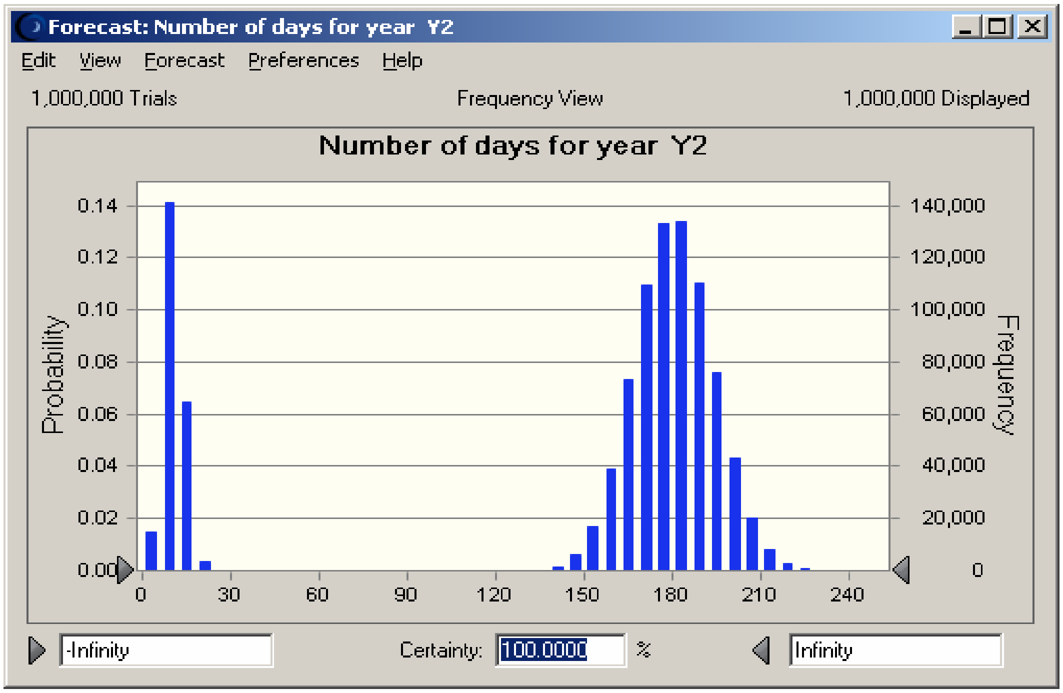
Certainty: 100.0000 %

Infinity

Figure 2: Year 1: Always inside the contingency period

In the second year, there is a small chance of securing an LNG contract. The resulting distribution of the number of days when the equipment is operating has two modes: Poisson (10) -after the contingency period- and Poisson (180) inside the contingency period, see Figure (3).

In year 3, there is an increased chance that we secure an LNG contract, so the probability of the equipment operating in Poisson (180) mode is lower than



1,000,000 Trials

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-Infinity

Certainty: 100.0000 %

Infinity

Figure 3: Year 2: Some scenarios are inside the contingency period and some are outside

in Poisson (10) mode. This is depicted in Figure (4) where the second mode is prevailing.

In year 8, there is little chance that we are still without an LNG contract. This is reflected in Figure (5) where the mode for the contingency period (Poisson(180)) has negligible probability.

For a period of 20 years, we draw 1 million scenarios for the contingency period. For each scenario, there are some years inside the contingency period and the remaining are outside. Figure (6) plots the distribution of the yearly average number of days when the equipment is operating over the 20 years period.

3 Decision Making under Uncertainty

After modeling the number of days the MSO equipment is operating, this section presents a theoretical example of comparison between two MSO solutions – reliquefaction and HP compression[1].

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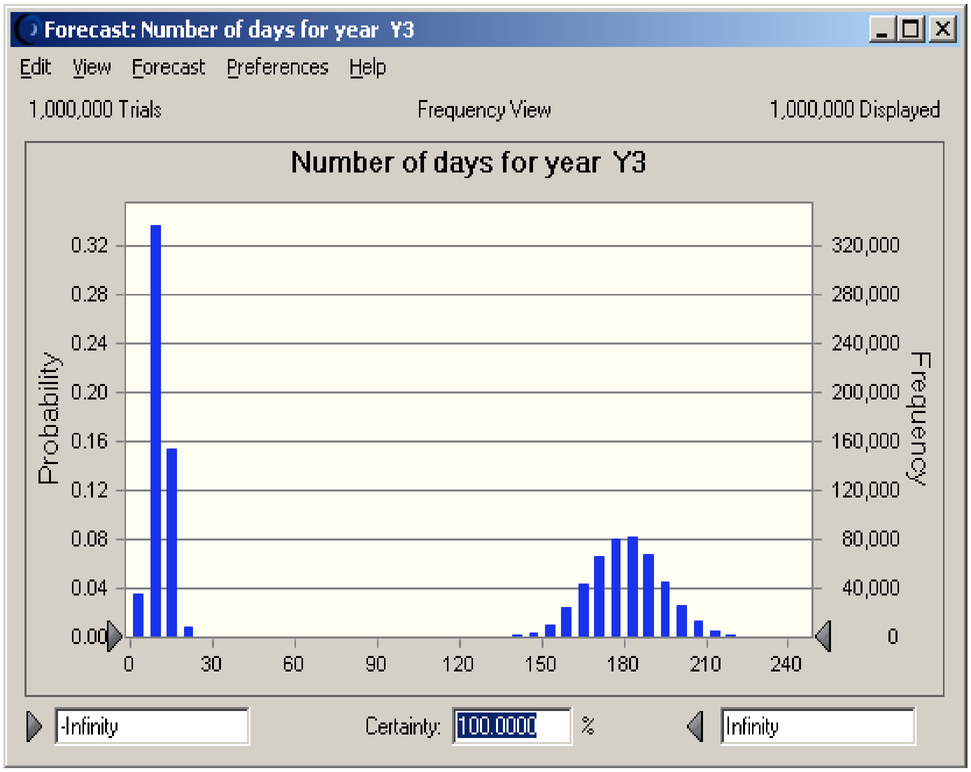
[1] **Important disclosure**: all input figures in this example – CAPEX, OPEX, electricity consumption, spreads – are for illustration purposes only (these are neither real estimates nor



1,000,000 Trials

Frequency View

1,000,000 Displayed

-Infinity

Certainty: 100.0000 %

Infinity

Figure 4: Year 3: More scenarios are outside the contingency period and some are inside

Example assumptions:

1. Terminal size 6 BCM
2. Electricity cost - flat €50/MWh in year 1 inflated at 2% p.a.
3. LNG spot premium to local gas market price - €2.5/MWh (for the options value)
4. MSO equipment input data:

	CAPEX (€mln)	Fixed OPEX p.a	Electricity consumption	MSO Rate
Re-liquefaction	25	1.5% CAPEX	9 MW	0%
HP compression	19	1.5% CAPEX	1 MW	2%
Do nothing	0	0	0	20%

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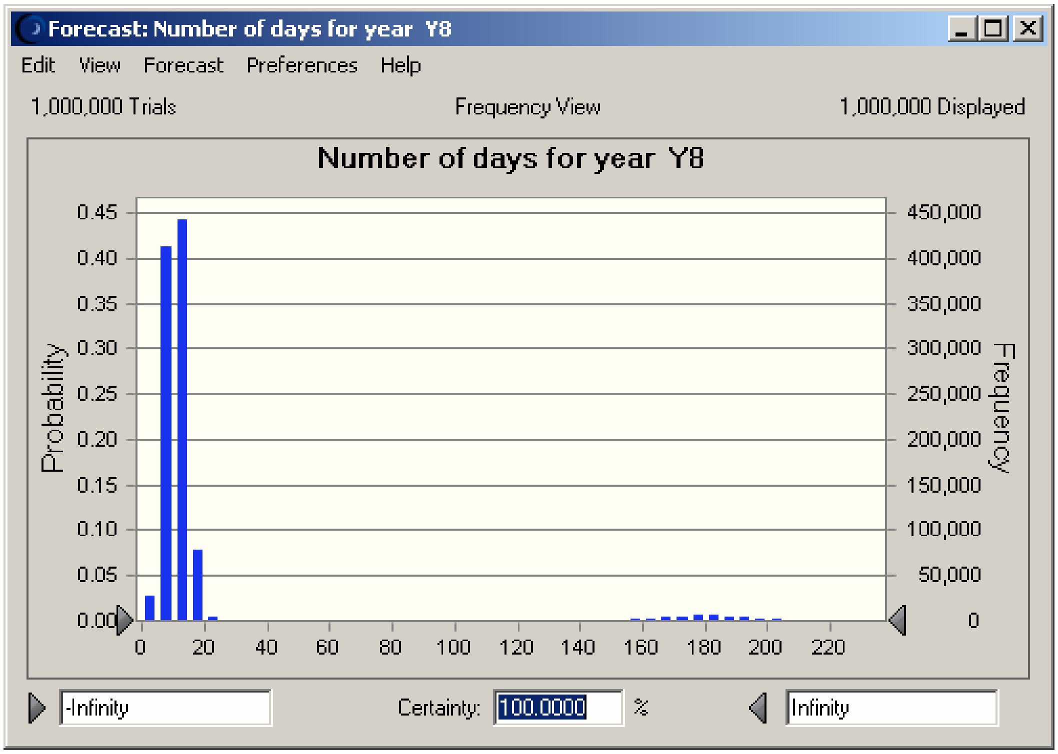
quotes from OEMs)



1,000,000 Trials
Frequency View
1,000,000 Displayed

-Infinity
Certainty: 100.0000 %
Infinity

Figure 5: Year 8: Most of the scenarios are outside the contingency period

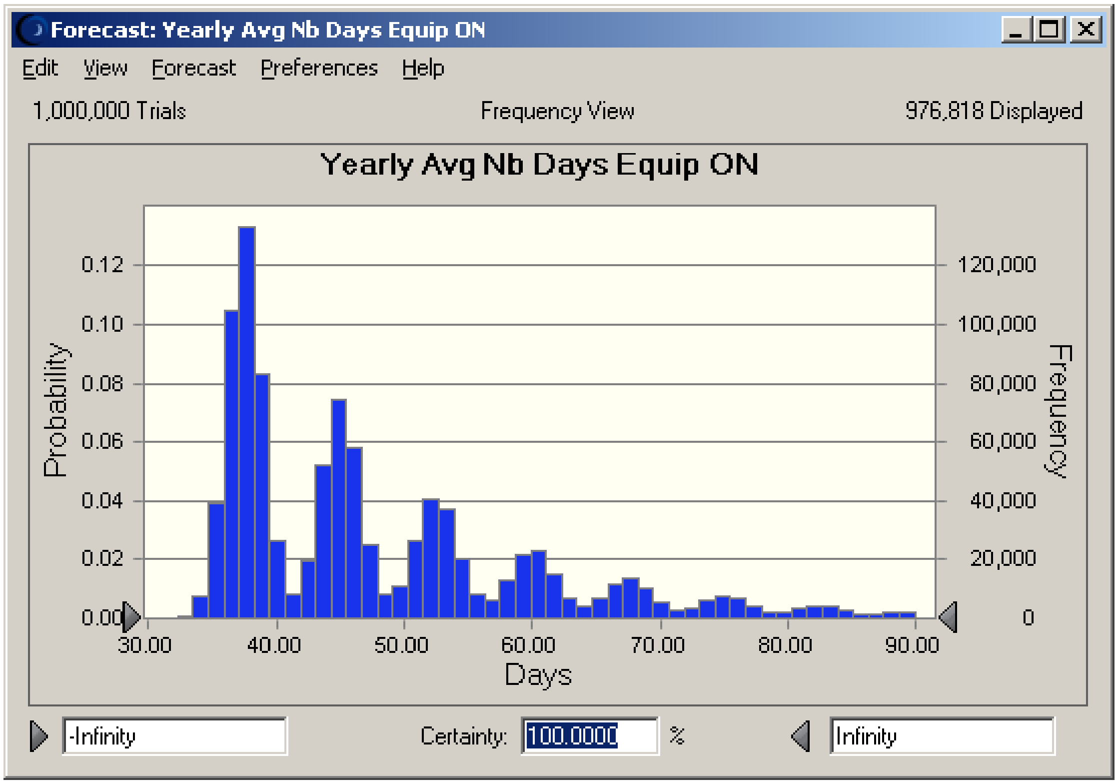
3.1 Different Options to Consider

3.1.1 Do Nothing

One might decide that the CAPEX and OPEX of the equipment are too expensive and opts for having full exposure to LNG spot prices. This exposure is mainly present during the contingency period where no LNG contract is secured. This period is random and modeled such that there is 99% chance of ending within 10 years time (see the previous section). The resulting distribution of cashflow NPV and its corresponding statistics and percentiles are depicted in Figures (7), (8) and (9) respectively.

3.1.2 Re-Liquefaction

In the case when a re-Liquefaction unit is selected, then there are OPEX and CAPEX costs incurred as described in high level at the outset of this section. There is however no exposure to LNG spot prices and an increased optionality in diverting the cargos if they proved to be more profitable in other markets. The resulting distribution of cashflow NPV and its corresponding statistics and



1,000,000 Trials

Frequency View

976,818 Displayed

-Infinity

Certainty: 100.0000 %

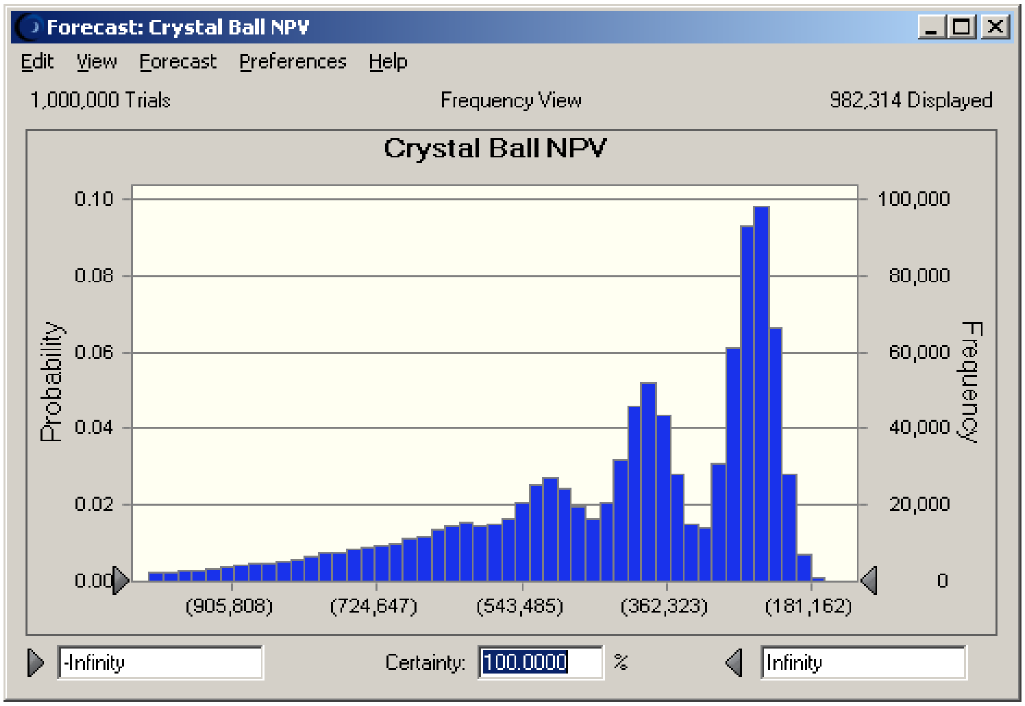
Infinity

Figure 6: Yearly average of number of days the equipment is switched on over the 20 years period

percentiles are depicted in Figures (10), (11) and (12) respectively. The diversion option is however not included in this plot.

3.1.3 HP compression

In the case when an HP compression unit is selected, then there are OPEX and CAPEX costs incurred as described in high level at the outset of this section. There is however non-zero exposure to LNG spot prices and an increased optionality in diverting the cargos if they proved to be more profitable in other markets. The resulting distribution of cashflow NPV and its corresponding statistics and percentiles are depicted in Figures (13), (14) and (15) respectively. The diversion option is however not included in this distribution.



1,000,000 Trials

982,314 Displayed

-Infinity

Certainty: 100.0000 %

Infinity

Figure 7: NPV distribution when no MSO equipment is selected

3.2 Decision making

3.2.1 Intrinsic NPV Comparison

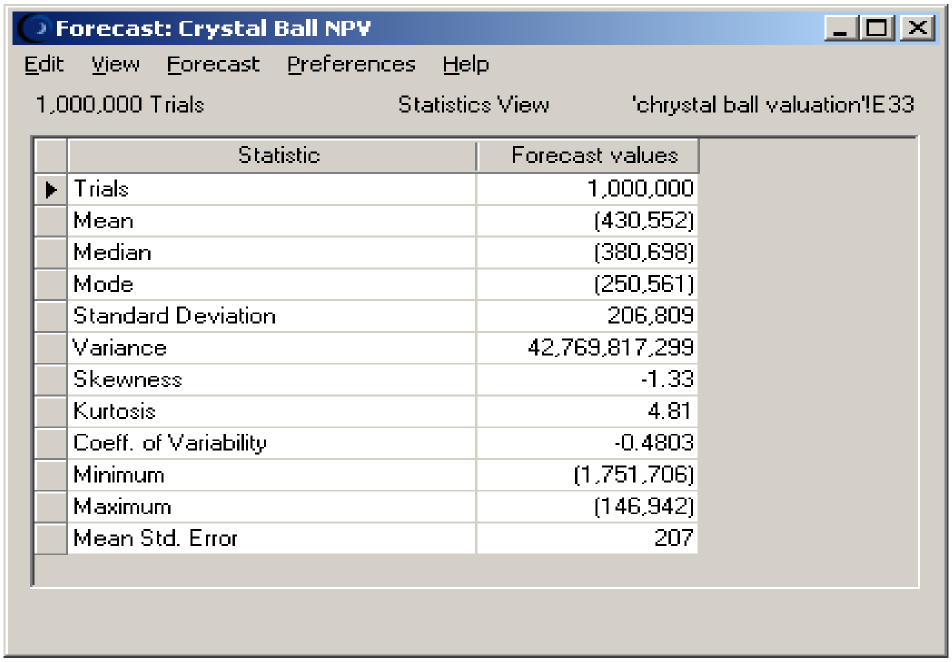
After computing the NPV distribution, one can make a decision based on the following criteria:

$$E\,[NPV] + \lambda\,(P_{10}\,[NPV] - E[NPV])$$

where $\lambda > 0$ measures the risk aversion of the decision maker, $E\,[NPV]$ is the expected value of the NPV and $P_{10}\,[NPV]$ is the 10^{th} percentile of the NPV. This is pertaining to the RAROC approach where $P_{10}\,[NPV] - E[NPV]$ can be interpreted as the Value At Risk, since it measures the distance between the portfolio expected cost and the worse case scenario cost. The option with the highest corresponding risk adjusted NPV is the preferred one.

From the analysis above, it is clear that having an equipment has better outcome than doing nothing and being potentially penalized by the LNG spot market volatility.

In this particular example based on the assumption shown above between re-Liquefaction and the HP compression, with a RAROC of 20%, the HP compression option is preferred but not significantly better.



Statistic	Forecast values
Trials	1,000,000
Mean	(430,552)
Median	(380,698)
Mode	(250,561)
Standard Deviation	206,809
Variance	42,769,817,299
Skewness	-1.33
Kurtosis	4.81
Coeff. of Variability	-0.4803
Minimum	(1,751,706)
Maximum	(146,942)
Mean Std. Error	207

Figure 8: NPV distribution when no MSO equipment is selected

3.2.2 Full (intrinsic + extrinsic) NPV Comparison

From our standpoint we would look at making decision for/against different MSORU alternatives based on the full intrinsic and extrinsic values of the MSORU which would be:

$$\begin{aligned} Full\ MSORU\ NPV &= NPV_1(intrinsic) + NPV_2[diversion\ option] \\ &\quad + NPV_3[Flexibility\ option\ value] \end{aligned}$$

When the LNG spot – local gas price spread is negative then the MSORU should be running. Therefore, this methodology could be used for estimating number of days when LNG spot – local gas price spread is negative.

- In case of Do Nothing: $NPV_2 = 0$ and NPV_3 is negative and is the extrinsic value of buying LNG on the spot for MSO rate volumes.
- In case of re-Liquefaction: $NPV_3 = 0$ (0% MSO rate) and NPV_2 is the extrinsic value of diverting cargoes.
- In case of HP Compression: 2% of gas still has to be sent out i.e. NPV_2 is 98% of the extrinsic value of diverting cargoes and NPV_3 is negative value of buying LNG on the spot for 2% MSO rate[2].

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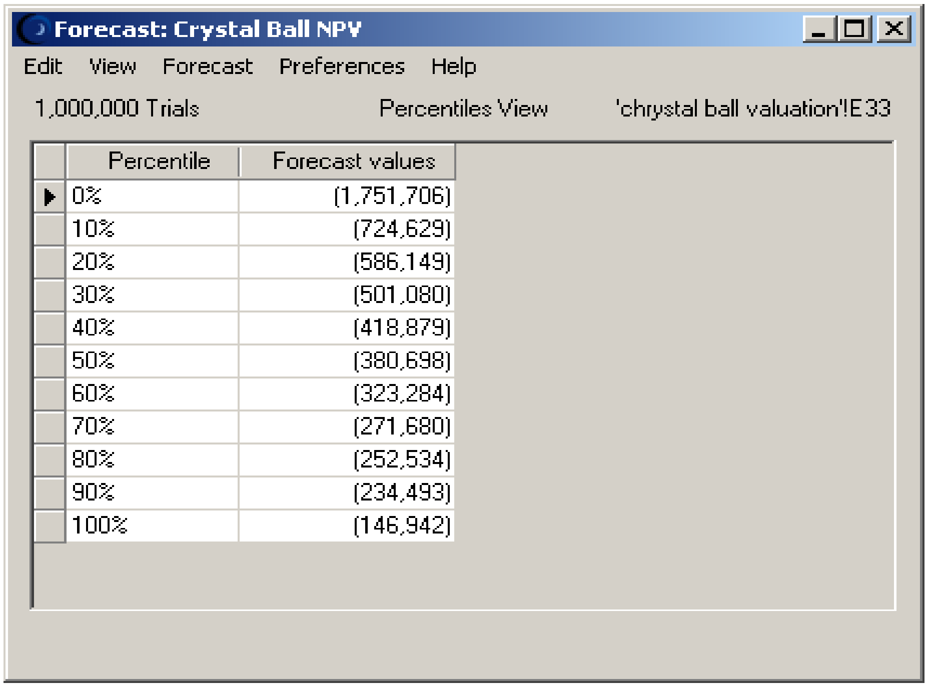
[2] Options value calculations for NPV2 and NPV3 are outside of this paper remit.



1,000,000 Trials

Percentiles View

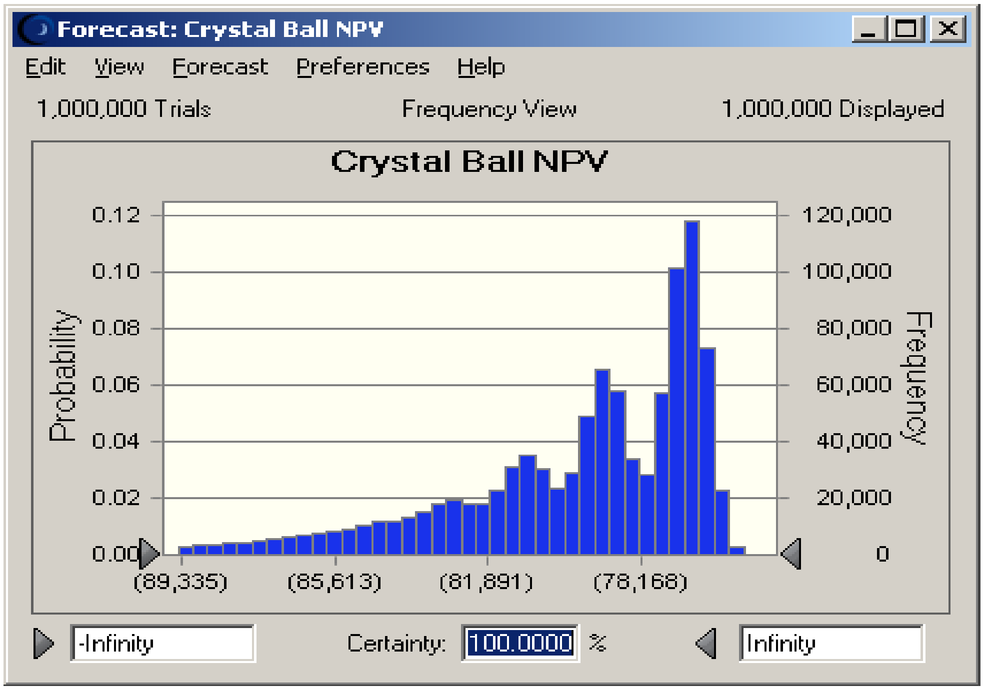
'chrystal ball valuation'!E33

Percentile	Forecast values
0%	(1,751,706)
10%	(724,629)
20%	(586,149)
30%	(501,080)
40%	(418,879)
50%	(380,698)
60%	(323,284)
70%	(271,680)
80%	(252,534)
90%	(234,493)
100%	(146,942)

Figure 9: NPV percentiles when no MSO equipment is selected

3.3 Conclusion

In this paper we have provided a framework for selecting the best alternative amongst Minimum Send Out Reduction Unit equipment. A special focus was on modelling the operational time of the unit, which it is the key random variable in selecting MSORU. Having a method for simulating this variable is the first step in developing a proper decision making under uncertainty. While our business case did not put up a real data because of its commercially sensitive nature, we have discussed the major steps involved in making this kind of decisions.



1,000,000 Trials

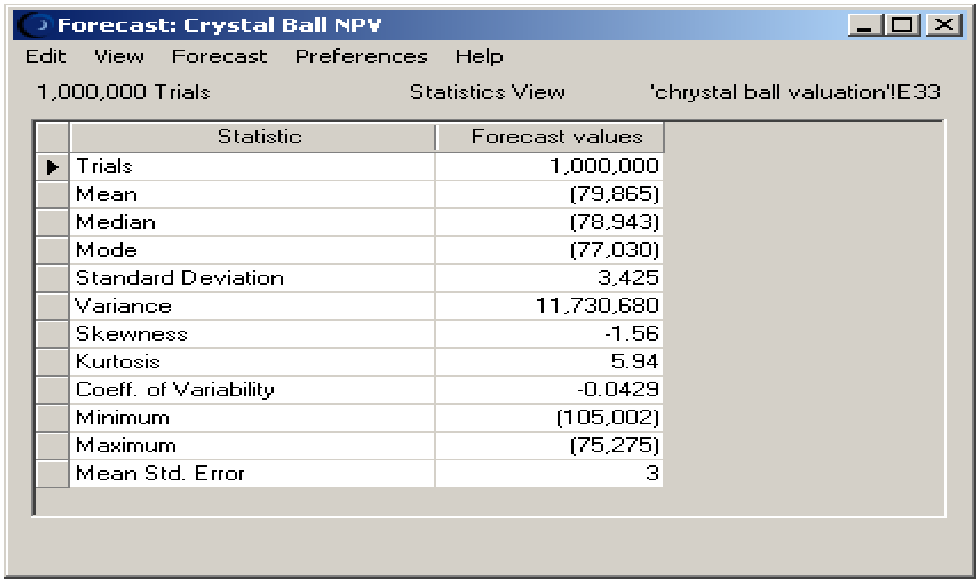
1,000,000 Displayed

-Infinity

Certainty: 100.0000 %

Infinity

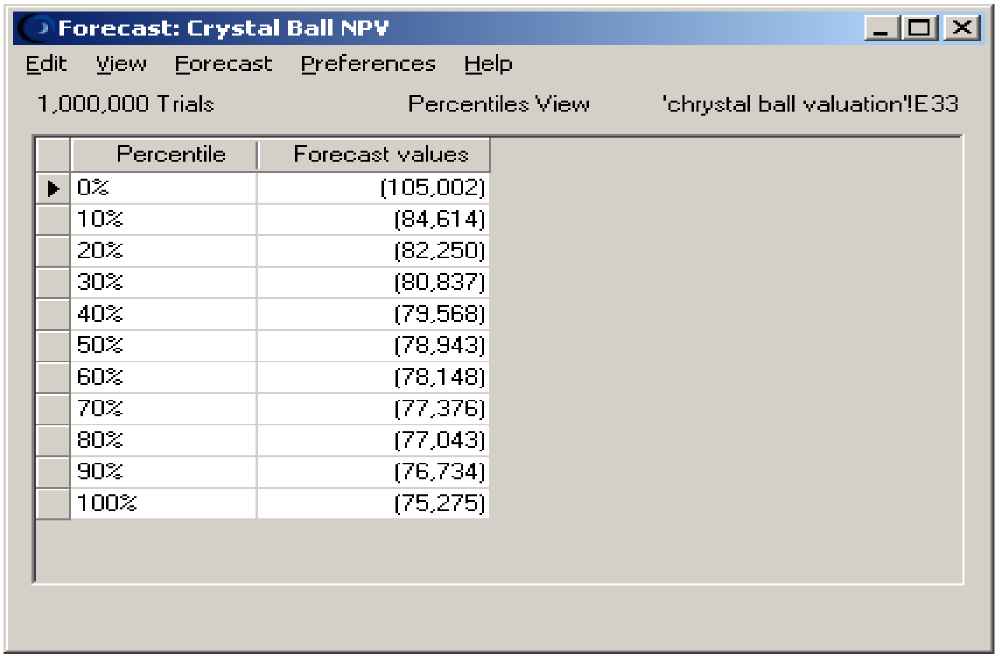
Figure 10: NPV distribution when reliquifaction equipment is selected



1,000,000 Trials Statistics View 'chrystal ball valuation'!E33

Statistic	Forecast values
Trials	1,000,000
Mean	(79,865)
Median	(78,943)
Mode	(77,030)
Standard Deviation	3,425
Variance	11,730,680
Skewness	-1.56
Kurtosis	5.94
Coeff. of Variability	-0.0429
Minimum	(105,002)
Maximum	(75,275)
Mean Std. Error	3

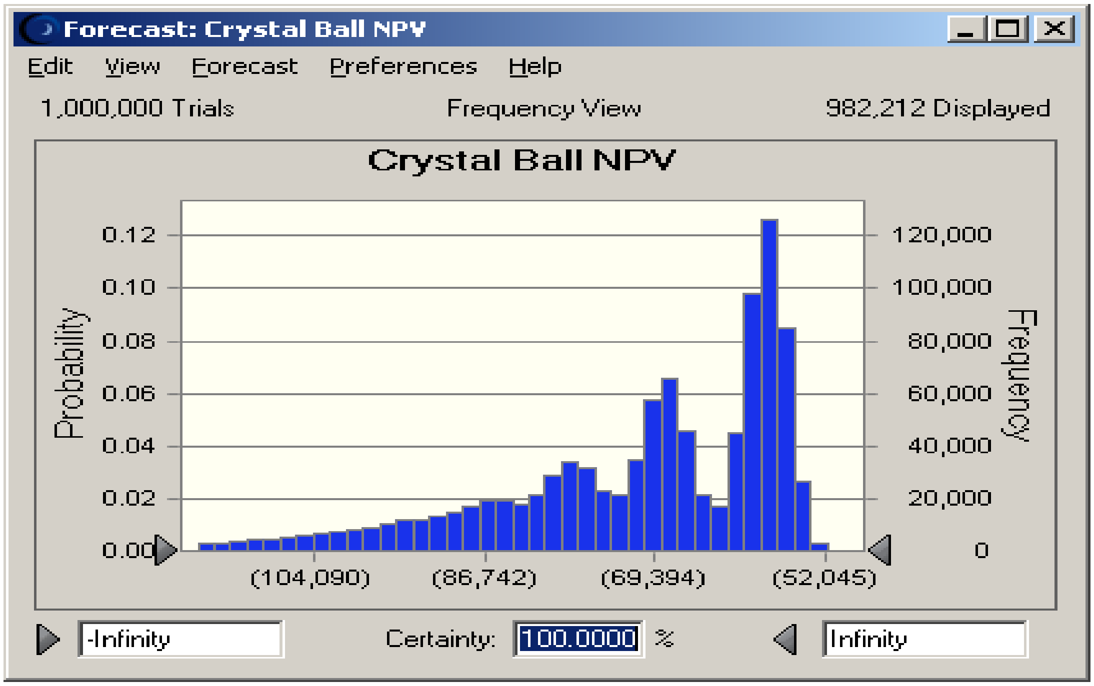
Figure 11: NPV statistics when reliquifaction equipment is selected



1,000,000 Trials Percentiles View 'chrystal ball valuation'!E33

Percentile	Forecast values
0%	(105,002)
10%	(84,614)
20%	(82,250)
30%	(80,837)
40%	(79,568)
50%	(78,943)
60%	(78,148)
70%	(77,376)
80%	(77,043)
90%	(76,734)
100%	(75,275)

Figure 12: NPV percentile when reliquifaction equipment is selected



1,000,000 Trials

Frequency View

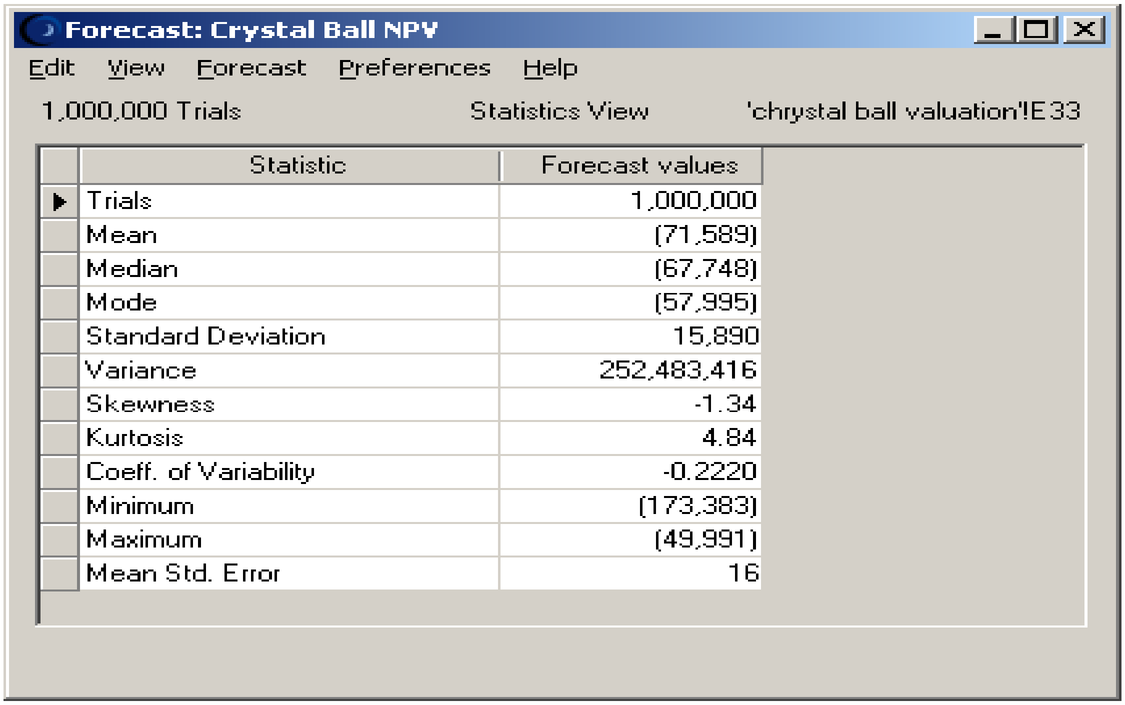
982,212 Displayed

-Infinity

Certainty: 100.0000 %

Infinity

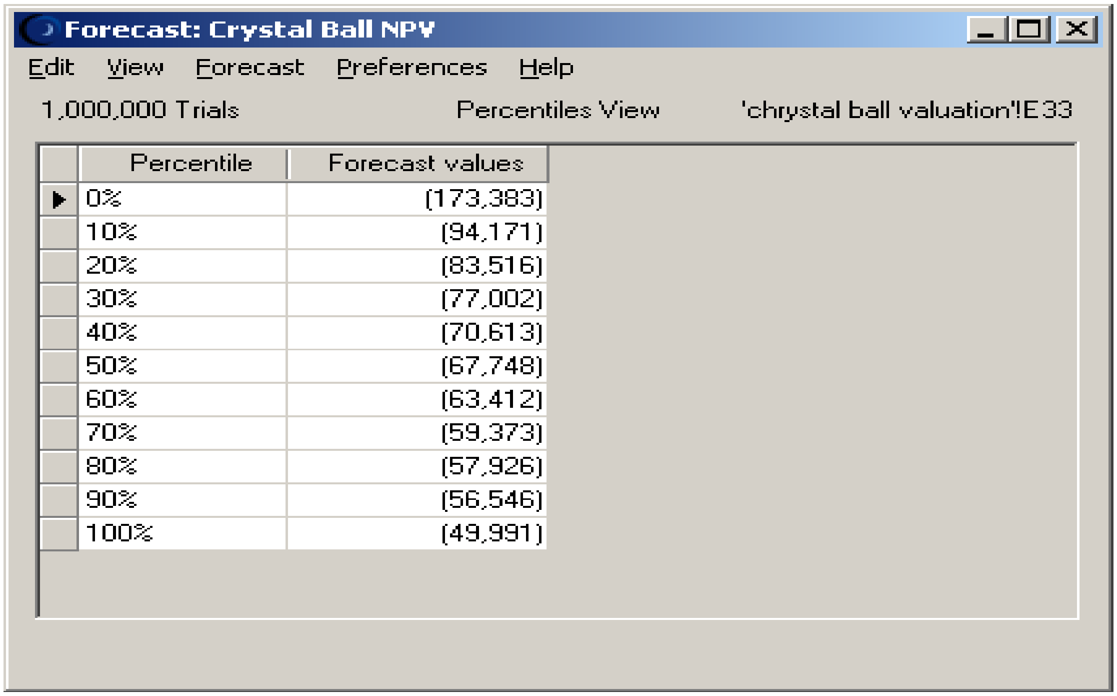
Figure 13: NPV distribution when HP compression equipment is selected



1,000,000 Trials Statistics View 'chrystal ball valuation'!E33

Statistic	Forecast values
Trials	1,000,000
Mean	(71,589)
Median	(67,748)
Mode	(57,995)
Standard Deviation	15,890
Variance	252,483,416
Skewness	-1.34
Kurtosis	4.84
Coeff. of Variability	-0.2220
Minimum	(173,383)
Maximum	(49,991)
Mean Std. Error	16

Figure 14: NPV statistics when HP compression equipment is selected



1,000,000 Trials Percentiles View 'chrystal ball valuation'!E33

Percentile	Forecast values
0%	(173,383)
10%	(94,171)
20%	(83,516)
30%	(77,002)
40%	(70,613)
50%	(67,748)
60%	(63,412)
70%	(59,373)
80%	(57,926)
90%	(56,546)
100%	(49,991)

Figure 15: NPV percentiles when HP compression equipment is selected