
Valuing Distressed Generation Assets



VALUING DISTRESSED GENERATION ASSETS

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Achieving an accurate valuation for distressed generation assets is of paramount importance. With most of the largest independent generation companies facing the need to restructure the debt that underlies their projects (or sell certain assets outright), less than rigorous valuation approaches could lead to a repeat of history on the debt side or a surrender of too much value on the equity side. In this environment, the need to apply more sophisticated analytical tools to the valuation of assets is essential. Failure to do so will likely lead to inappropriate valuations and less than optimal decisions.

Despite the increased complexities facing energy project analysts, many still employ the same approach to asset valuation as they have for years. However, traditional methodologies for the valuation of assets exhibit a number of shortcomings, such as:

- High-level financial pro formas do not capture the effects that dynamic, physical asset limitations have on generation asset value (e.g., costs to achieve optionality); and, hence, they do not represent real asset value.
- The level of precision and functionality afforded by spreadsheet environments limit flexibility in the analysis of the physical characteristics of generation assets.
- Some financial models do not optimize in response to multiple project inputs and constraints.
- Generation plants have operational constraints that restrict their ability to respond to market changes; therefore, traditional Black-Scholes models, which more or less assume an instant on/off capability, are inappropriate tools.

At Rudden, we believe that determining the true value of an asset, or portfolio of assets, requires a simulation-based analysis capable of capturing both the intrinsic and extrinsic (optional) values taking into account all operational constraints (Figure 1). In addition, the analysis should also include the use of a Monte Carlo-based tool to simulate a wide range of possible price trajectories and other variables. It will yield a distribution of profits, rather than a point estimate, that can be used to assess earnings at risk and calculate an appropriate asset or portfolio value under real world conditions.

Traditional Approach	Simulation-Based Approach
<ul style="list-style-type: none"> • Plants are physical assets that convert fuel into electricity • Valuation inputs: <ul style="list-style-type: none"> ▪ Expected capacity factor ▪ Expected average cost of fuel ▪ Expected average market price of electricity ▪ Precedent sale price/kW for similar plants 	<ul style="list-style-type: none"> • Many types of plants are more accurately viewed as call options on electricity whose exercise price is the price of fuel • Traditional valuation inputs plus: <ul style="list-style-type: none"> ▪ Volatility of fuel, electricity pricing ▪ Correlation between fuel, electricity pricing ▪ Operational flexibility (ramp-up/down time, start-up costs)

Figure 1: Simulation inputs capture plant and other constraints

Analyzing Revenue and Cost Streams

There are a number of revenue and cost streams that must be fully analyzed to develop an accurate generation asset valuation. Some of the more obvious include:

- Market prices
- Fuel costs
- Capacity factor
- Operations and maintenance (O&M) expenses
- Capital amortization

Less obvious, and more difficult to analyze, considerations such as revenue and cost streams associated with optionality include:

- Price volatility
- Unit flexibility
- Ancillary services such as spinning reserve, non-spinning reserve, regulation up, and regulation down
- Ramp-up, run time and ramp down
- Congestion costs/transmission credits

The cornerstone of Rudden's valuation is the development of an integrated revenue and cost model for the project that incorporates all of the impacts of optionality in addition to the economics of the sales contracts, supply contracts and market forecasts associated with the project (Figure 2). This type of analysis requires in-depth industry knowledge covering a broad array of factors, the most important of which include:

- Understanding sector and plant economics and their interrelation with sector and market regulations
- Assessing the alternatives at the project level and how they might positively or negatively impact the revenues that feed into the company
- Reviewing the engineering performance criteria (e.g., heat rates and forced outage rates) and output flexibility for a variety of electric generation assets
- Determining the plant's optionality (the ability to respond to market dynamics)
- Analyzing electric power, reserve and ancillary services markets, contracts, and uncertainties
- Evaluating fuel supply contracts and associated alternatives
- Developing correlations between power costs and fuel prices
- Identifying the location and extent of physical (e.g., transmission) constraints
- Integrating environmental restrictions

The Rudden Methodology

The Rudden methodology involves two stages: (1) a deterministic analysis stage, and (2) a financial analysis stage. In the deterministic analysis stage, the present values of the revenue and income streams are appraised using predicted values of the market for electrical energy and ancillary services. Fuel and production costs are also evaluated, using a production cost program based on an optimization simulation algorithm. Stage one is commonly referred to as an engineering analysis. The result of this stage is the intrinsic value of the asset.

In the financial analysis stage, market uncertainty, together with a model of the generator's optionality (which, in this case, refers to the ability of the unit to respond to market conditions), is considered and the expected extrinsic value, together with a measure of value-at-risk, is developed. This stage uses a Monte Carlo-based sampling and simulation model that combines the physical constraints of the plants with the volatilities associated with the power and fuel markets. Based on this simulation, a distribution of profits over the time horizon, for which expected profit and comprehensive risk measures are generated, is provided. The result of stage two is the extrinsic value of the asset.

When combined, the intrinsic and extrinsic values are equal to the total value of the generation asset.

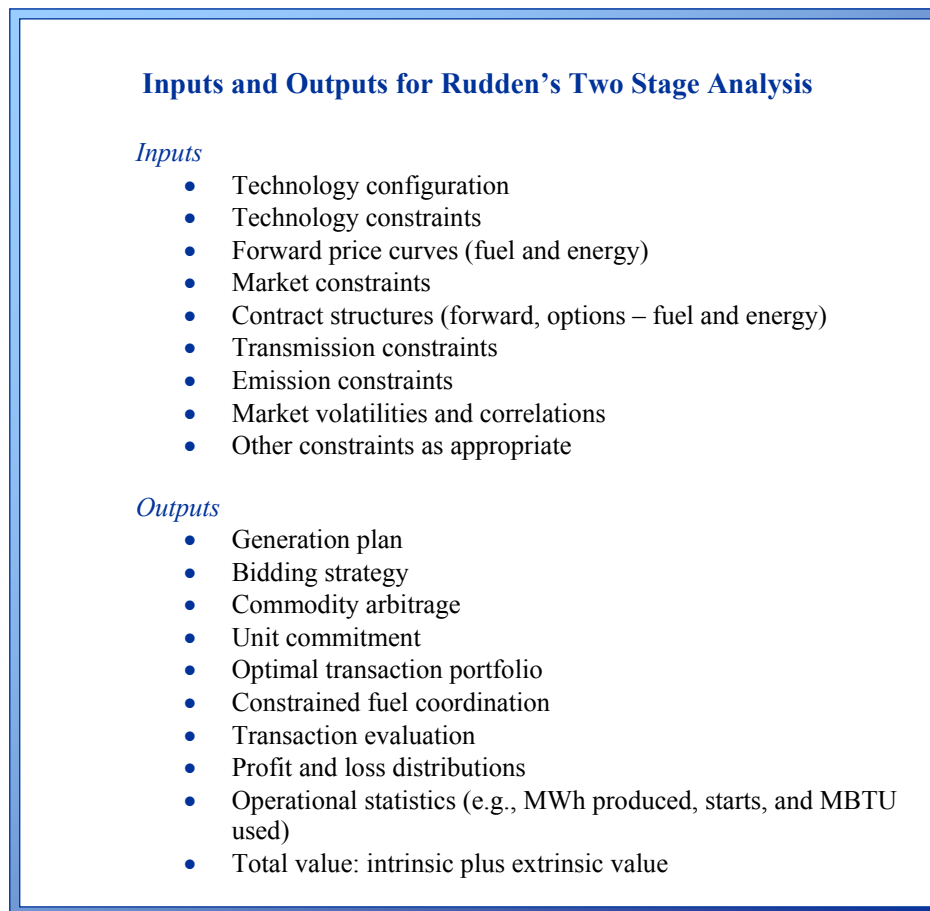


Figure 2: Simulation based analysis requires in depth industry knowledge covering a broad array of factors

The Rudden methodology uses the Power Costs, Inc. (PCI) two-stage GENTRADER® simulation model to capture the operation of the portfolio and the uncertainty in prices, quantity of full-service contracts and generation availability. GENTRADER® optimizes the hourly exercise of the associated physical and financial options to maximize profit for a number of deterministic scenarios. The optimization process uses hourly market price curves for energy, ancillary services, and fuel. It commits and dispatches generation units, and exercises long and short positions in forward and option contracts. The optimization is accomplished under fuel emission and transmission constraints (Figure 3).

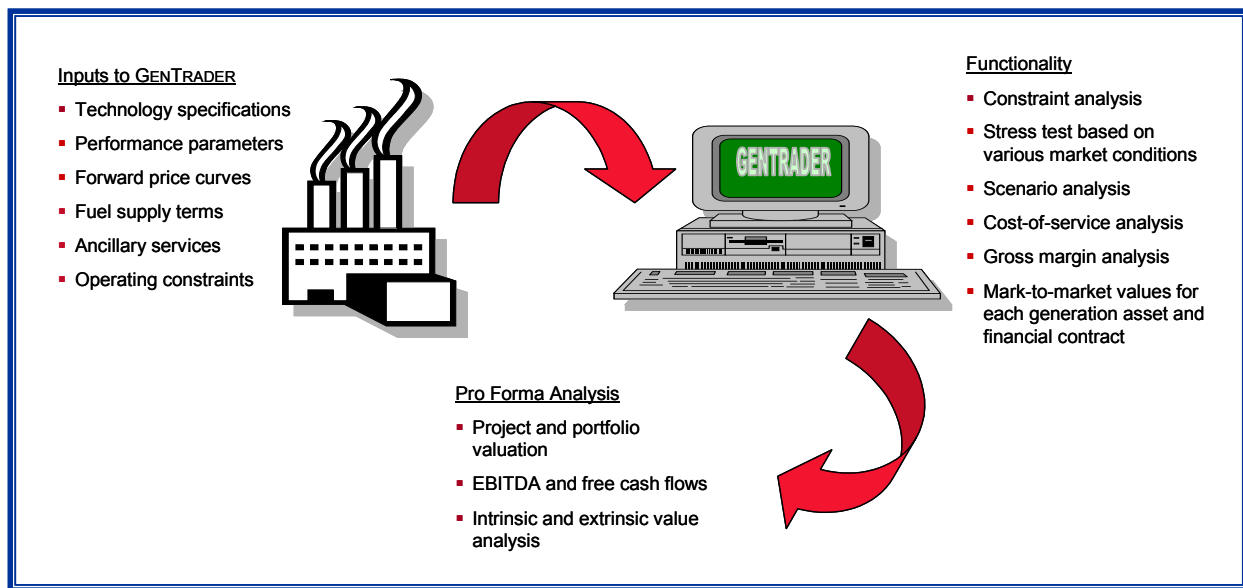


Figure 3: The Rudden methodology uses the Power Costs, Inc. (PCI) two-stage GENTRADER® simulation model

These simulations cover all possible outcomes as determined by volatilities of prices, time between the present and the time of operation, variance of the contract quantities and availability rates – the “sample space.” From the results of the first stage, the partial derivatives, or “deltas” of the profit portfolio – the rate of change of profit when only one of the risk drivers is changed – with respect to each of the risk drivers is estimated at a number of locations within the sample space. The deltas are then used to form a describing function that represents profit over the simulation horizon as a function of the uncertain, or stochastic variables. Finally, Monte Carlo simulation is used to estimate the distribution of profit.

Case Study

To demonstrate our methodology, we evaluated three different types of generating plants: (1) a 200 MW natural gas steam turbine, (2) a 50 MW natural gas combustion turbine, and (3) a 600 MW natural gas combined cycle plant featuring two combustion turbines, one steam turbine, and duct firing. The characteristics of these three generating plants are shown in Figure 4.

	Case Study Generating Plants		
	200 MW Gas	50 MW CT	600 MW CC
Type	Steam turbine	Combustion turbine	Combined cycle
Fuel	Natural gas	Natural gas	Natural gas
Capacity (MW)	200	50	575
Average Heat Rate (Btu/kWh)	10,800	13,300	7,400

Figure 4: Case study portfolio

The simulation model output provides detailed and accurate hourly unit commitment and dispatch (Figure 5). The example uses simulated hourly operation of the three plants over one week in January 2006 (Monday through Sunday) based on forecast prices for that period (\$3.91 for Natural Gas and \$42.63 for Energy) and an hourly price profile based on historical patterns in a specific region.

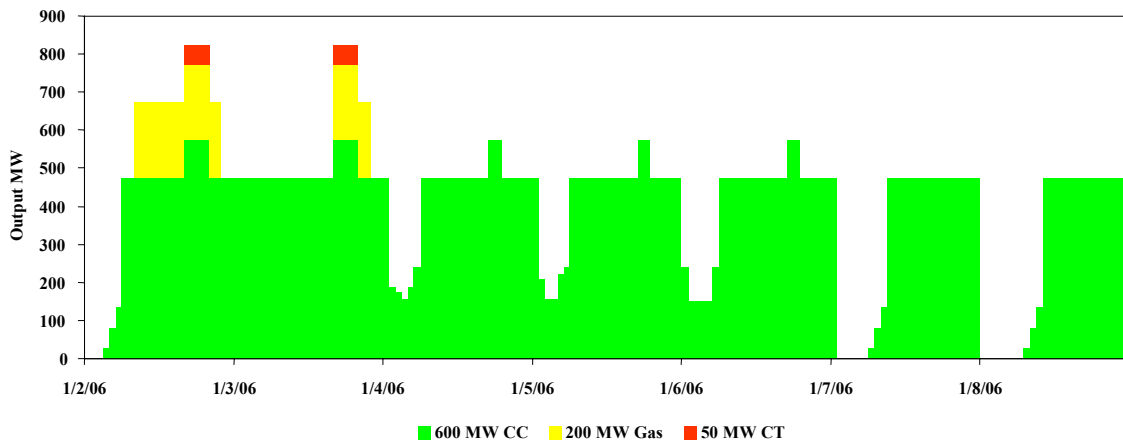


Figure 5: Hourly unit commitment and dispatch for the base case portfolio

The number of hours each unit is dispatched is related to its heat rate and operating constraints. The 600 MW combined cycle plant, containing units with the lowest heat rate, is dispatched every day. The other two plants are dispatched only on the first two days, when hourly prices are the highest. The 50 MW combustion turbine unit with the highest heat rate runs for the smallest number of hours.

As a reminder, the combined cycle plant is configured as two combustion turbines, one steam turbine, and duct firing. Figure 5 shows that in this plant the first combustion turbine unit will operate continuously from Monday morning through Friday evening. It is also economic to operate the steam turbine whenever either of the combustion turbines is running. The output from one combustion turbine, plus the capacity that can be obtained from the steam turbine, can range between 150 MW and 240 MW. In our case study, the generator prices dip below the level required to maintain profitable operation of the plant in the off-peak hours of Wednesday, Thursday, and Friday mornings, yet the first unit remains on at or near minimum capacity in those hours rather than shutting down because of operational constraints captured by the model. The second unit, for which the operating constraints are less restrictive, shuts down completely for those hours. Both units shut down in the early hours of Saturday and Sunday. The plant operates both units at maximum through Tuesday morning, because prices remain high enough. Duct firing operates for a few peak hours each weekday.

As noted earlier, GENTRADER®’s simulation-based analysis allows for full representation of plant operating constraints. To illustrate the impact of these constraints on valuation, a second case (the “Unconstrained Case”) was analyzed, in which the constraints in the original case were relaxed in the same manner as in a tradition Black-Scholes approach (Figure 6).

Parameter	Combined Cycle Operating Parameters	
	Constrained	Unconstrained
Maximum Ramp Rate	4.5 MW / min	15 MW / min
Minimum Up Time	4 hours	1 hour
Minimum Down time	4 hours	1 hour
Start-Up Profile	Requires 3 hours to reach 135 MW	Can start up immediately

Figure 6

Figure 7 looks only at the 600 MW combined cycle plant and shows the dispatch variance for these two cases. The green shaded area represents the original, combined cycle plant simulation under constrained conditions. This profile is identical to the one displayed in Figure 5. The blue diamonds show the dispatch of the combined cycle plant using a Black-Scholes unconstrained approach. In most hours, the two units operate at the same output level. However, in some off-peak hours the dispatch is very different. This is most obvious in the mornings of Wednesday, Thursday, and Friday. During these times, the entire plant shuts down under unconstrained conditions, while the one unit is kept running under constrained conditions.

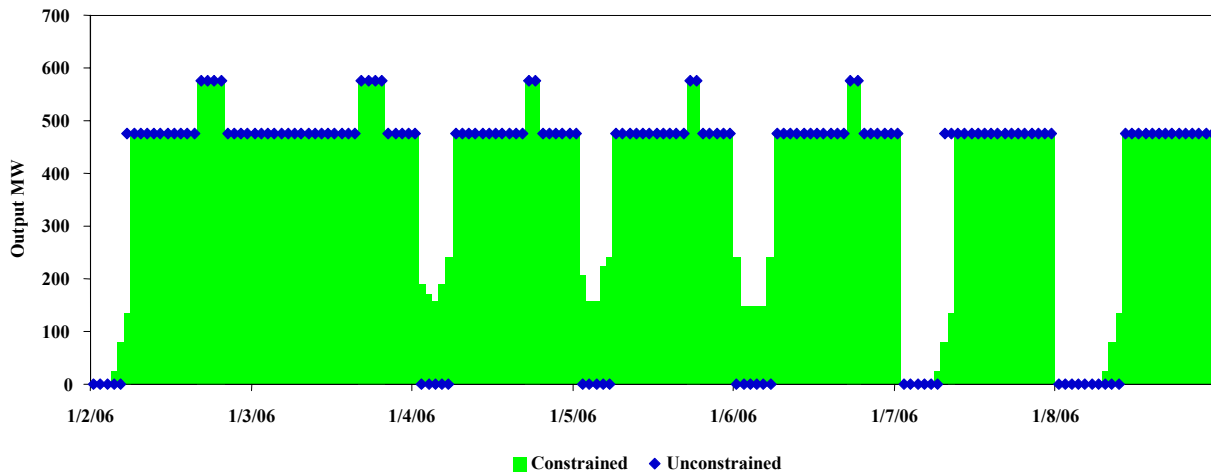


Figure 7: Dispatch variance for constrained versus unconstrained cases

The reason for the dispatch variance is the 3-hour start-up requirement identified earlier (Figure 6), or in other words, the constrained unit must be left running in order to be available for all in the money hours. The financial consequences of this dispatch variance is that the costs for operating the constrained units during the off peak intervals are lost in the unconstrained case. Figure 8 lists the results covering our one-week time horizon. In addition, it should be noted that units represented as being immediately available in the unconstrained case are not due to ramp rates, and thus revenues are overstated as well.

	Constrained	Unconstrained
Energy (MWh)	65,930	63,625
Revenue (\$)	2,596,661	2,541,843
Fuel Cost (\$)	1,887,294	1,809,247
O&M Cost (\$)	125,926	121,524
StartUp/ Shutdown Cost (\$)	22,555	30,067
Gross Margin (\$)	560,886	581,005
Average Revenue (\$/MWh)	39.39	39.95
Average Cost (\$/MWh)	30.88	30.82
Average Gross Margin (\$/MWh)	8.51	9.13

Figure 8: Financial results covering a one-week time horizon

It is through the careful representation of operating constraints that the Rudden Methodology featuring GENTRADER® software provides accurate modeling of unit commitment, dispatch, and financial results.

Returning to our case study, we can examine the portfolio’s performance. Figure 9 shows the projected long-term monthly results for each of the three generating plants for one year (2006). The monthly results show the seasonal variation in plant operations. Notice that, although the combined cycle plant operates every month, the steam turbine and combustion turbine units are each idle for a few months in the spring and fall. All three plants have their highest utilization in the summer, when higher electricity demand pushes market prices higher.

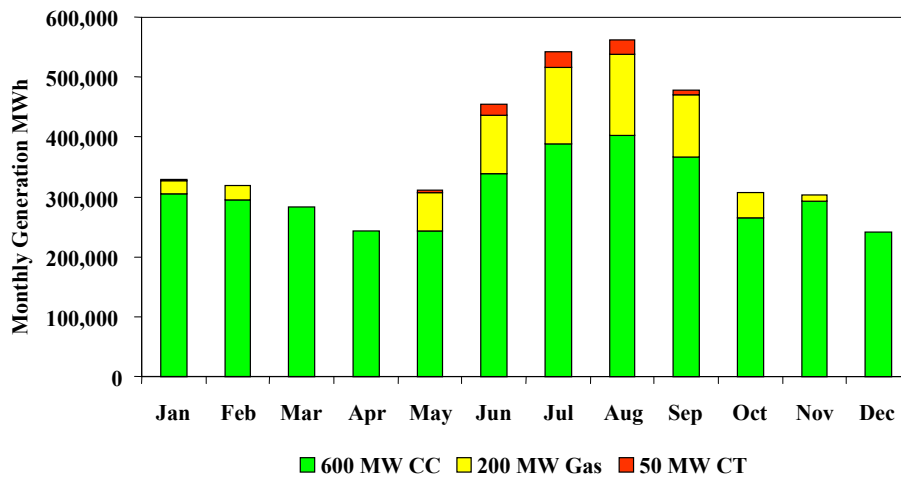


Figure 9: Long-term monthly results for each of the three generating plants for one year (2006).

For the longer-term view, we input fuel prices as shown and long-term annual operational results were developed (Figure 10); these annual results show the impact of evolving market conditions. In base case region for the first two years, the market is working down a projected surplus. Starting in 2005, the market is forecast to be in balance. Other regions may take longer to reach that balance.

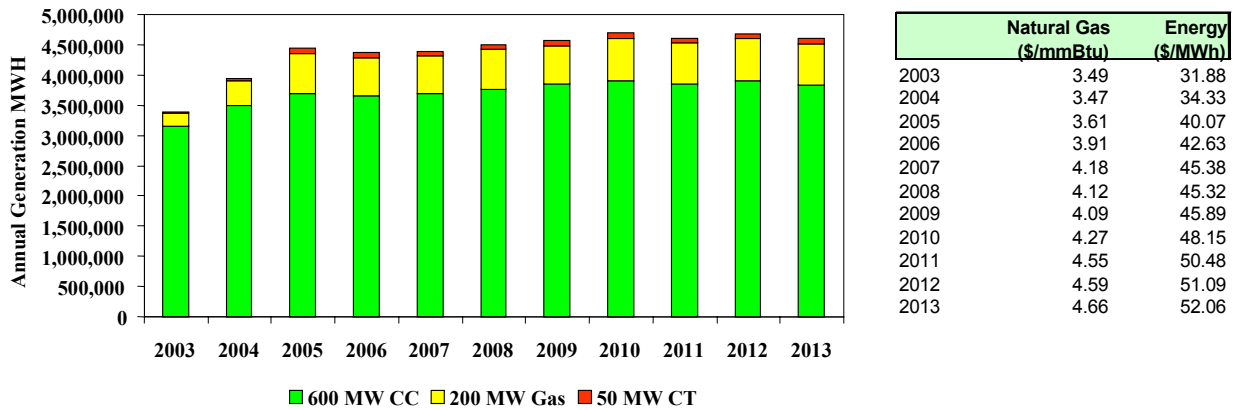


Figure 10: Long-term annual operational results

The impact of evolving market conditions on plant operations is magnified in the financial results, as shown in Figure 11. Although total energy output for the three units increases 35% from 2003 to 2013, gross margin increases by nearly 200% for the combined cycle plant and more than 700% for the combustion turbine plant.

The financial results shown are based on base case forecast assumptions, including a balanced market after the surplus is worked down. It is quite possible that further boom/bust cycles will occur within the forecast horizon, as well as strong fluctuation in natural gas prices.

	Annual Gross Margin \$		
	600 MW CC	200 MW Gas	50 MW CT
2003	25,807,360	1,730,046	211,133
2004	35,617,230	3,495,369	416,094
2005	57,162,260	9,874,885	1,442,652
2006	59,620,350	9,887,447	1,446,736
2007	63,626,910	10,391,320	1,541,389
2008	64,388,320	10,239,590	1,468,661
2009	67,361,280	11,231,300	1,668,753
2010	70,859,970	11,304,730	1,623,165
2011	73,108,620	11,516,910	1,641,785
2012	75,545,930	12,108,000	1,760,773
2013	76,371,070	12,210,890	1,752,286

Figure 11: Long-term base case financial results

To capture the impact of real-world uncertainties in the operational and resulting financial results of the portfolio, we analyzed four stress testing cases in addition to the base case. The combined set of five cases is the following: (1) base case, (2) higher power costs than in the base case, (3) lower power costs, (4) lower natural gas fuel costs than in the base case, and (5) lower natural gas prices. The alternative power price scenarios represent the impact of regional generation supply, demand balances and natural gas prices (Figure 12).

	Case				
	1 Base	2 Power -30%	3 Power +30%	4 Gas -30%	5 Gas +30%
Energy Generation (MWh)					
600 MW Combined Cycle	65,930	14,990	83,915	86,015	28,750
200 MW Gas Steam Turbine	4,000	0	26,413	31,555	0
50 MW Combustion Turbine	400	0	2,250	3,100	0

Figure 12: Stress tested operational results for the portfolio

The impact of market conditions on unit start-up, dispatch, fuel use, net operating revenue, and many other results can be examined using the simulation model. This is illustrated in Figure 13 for the 600 MW combined cycle plant. Gross margin range between about \$39,000 and \$1.4 million over the five scenarios.

	Case				
	1 Base	2 Power -30%	3 Power +30%	4 Gas -30%	5 Gas +30%
Gross Margin (\$)	560,886	37,932	1,435,229	1,238,016	171,947
Energy (MWh)	65,930	14,990	83,915	86,015	28,750
Fuel (mmBtu)	481,453	110,718	628,399	654,899	208,735
Total Hours On-Line	153	47	168	168	73
Total Number of Start-Ups	14	8	13	11	10
Capacity Factor	65.4%	14.9%	83.3%	85.3%	28.5%
Average Cost (\$/MWh)	30.88	32.2	31.32	22.88	39.76
Average Heat Rate (Btu/kWh)	7,303	7,386	7,489	7,614	7,260

Figure 13: Stress tested financial results for the combined cycle plant

To reach an accurate portfolio valuation, Rudden's methodology uses a Monte Carlo simulation of plant operation under thousands of market conditions. This enables an analysis of the risk inherent in a generating asset taking into account the relative likelihood of the range of outcomes. Figure 14 shows the Monte Carlo analysis for the 2006 forecast year.

	600 MW CC	200 MW GAS	50 MW CTI
Gross Margin (\$)			
Mean	89,023,064	24,988,896	4,952,267
Std Deviation	35,445,912	11,778,185	2,713,403
Intrinsic	59,620,352	9,688,478	1,441,370
Energy (MWh)			
Mean	2,827,588	833,403	160,520
Std Deviation	553,104	213,631	49,798

Figure 14: Monte Carlo analysis for the 2006 forecast year

In this year, the intrinsic gross margin (\$59.6 million for the 600 MW combined cycle plant) is the value obtained from the base case for 2006. The expected or mean value of gross margin (\$89.0 million) is significantly higher, due to the asset's operating flexibility and market volatility. The difference between the mean and intrinsic values, approximately \$29.4 million, is the extrinsic, or optionality, value of the asset. From a risk management

point of view, it is extremely important to assess the range of financial outcomes and their probabilities. The probability distribution of gross margin (Figure 15) illustrates the entire spectrum of possibilities. From the distribution one can derive earnings-at-risk estimates. For example, there is a 5% chance that the gross margin of the combined cycle unit will fall below \$39.7 million.

Using Rudden's simulation methodology featuring GENTRADER®, the total plant value (intrinsic + extrinsic) would be \$ 89.0 million in the year shown. If the traditional Black-Scholes methodology were used and depending on the plant constraints, the plant value could have been overstated by as much as 10% to 30%.

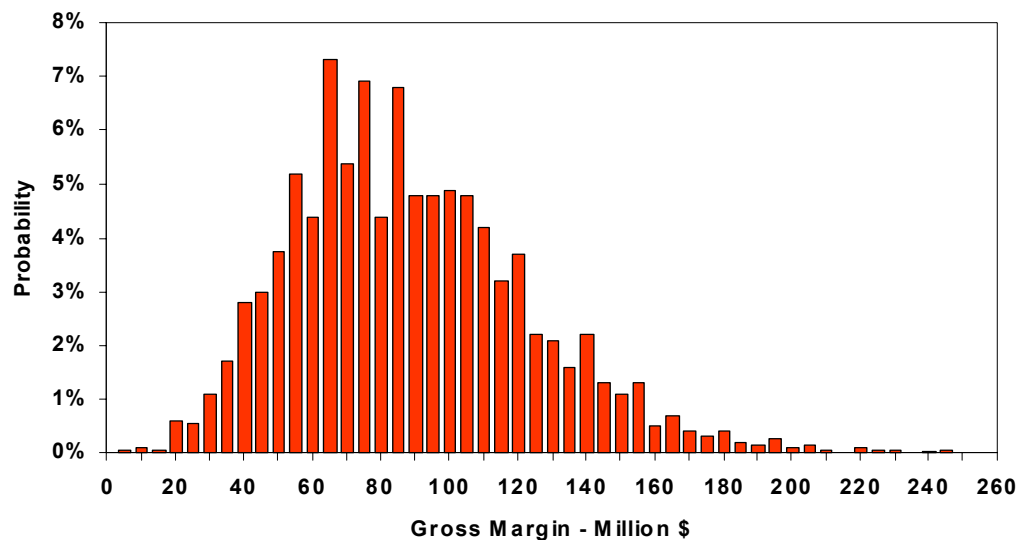


Figure 15: Gross margin histogram for 600 MW CC

Conclusion – The Need for More Sophisticated Valuation Analyses

The distressed market has put a large number of projects at risk; there is a lot of money at stake. S&P reported in November 2002 that energy companies have \$90 billion in medium-term debt that will need to be refinanced between 2003 and 2006; 30 percent of this amount is currently in or near default. Power companies have been hard hit and, according to a recent survey of 25 energy executives conducted by the Bauer College, nearly two-thirds of the executives do not expect the industry to emerge from its credit rating crisis before the second half of 2004.

As shown in Figures 16, long-range forecasts predict that generation project financials will be squeezed even tighter than they are today because the rate of rise in natural gas prices is expected to outpace the rate of rise in generator prices for many years. This asynchronous relationship is driven by increased natural gas usage in areas unrelated to gas-fired generation coupled with slow electricity load growth forecasts impacted by market saturation of high-use appliances such as air conditioners, power efficiency gains in electric power usage generally, and more effective demand management processes. Spark spread narrowing will follow this trend (Figure 17). Figure 18 shows the competitive position of the 600 MW gas-fired plant versus coal and nuclear plants.

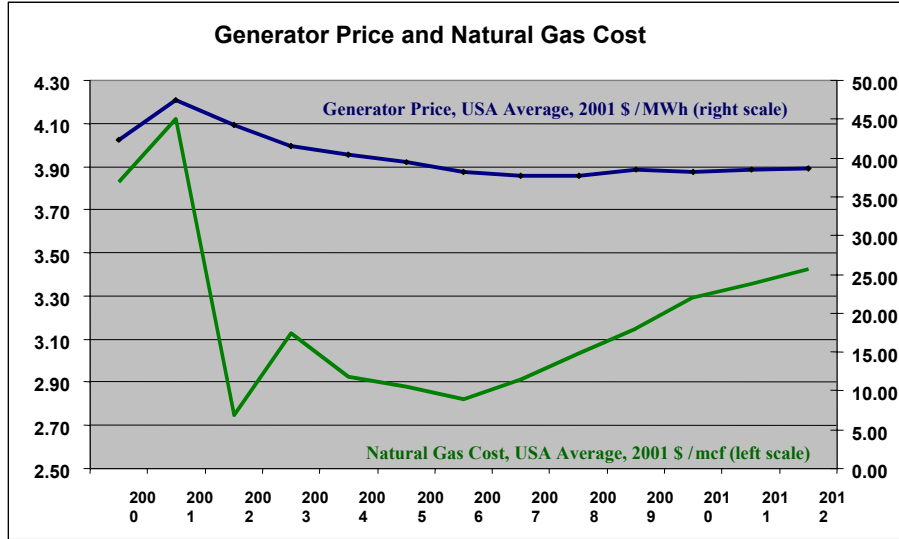


Figure 16: The rate of rise in natural gas prices is expected to outpace the rate of price rise in generator prices. Source: EIA Annual Energy Outlook, January 2003

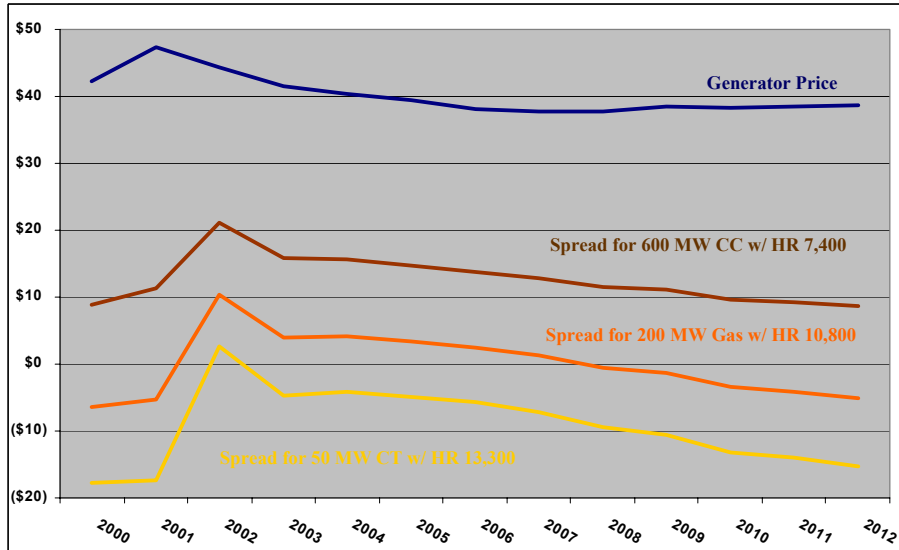


Figure 17: Spark spreads are expected to narrow. Source: EIA Annual Energy Outlook, January 2003

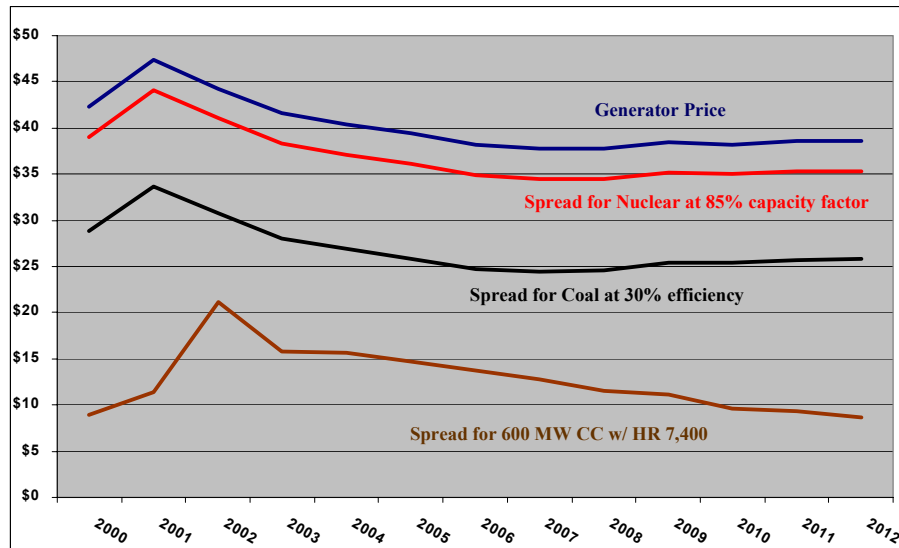


Figure 18: Natural Gas will be less competitive than Coal or Nuclear. Source: EIA Annual Energy Outlook, January 2003

In response to these changing market dynamics, energy companies are now mothballing some plants, stopping early construction, putting development plans on hold, and hanging the “For Sale” signs on existing assets. Additionally, many project owners are being forced to restructure their financing, either on a project-specific basis or at a corporate level. Refinancing will occur at higher costs, putting additional pressure on energy companies already experiencing financial problems. Understandably, these companies do not want to give up too much as part of the restructuring. At the same time, financial companies want to ensure that they receive fair value for their contributions.

To fairly achieve both objectives, accurate asset and portfolio valuation is required. The changing regulatory environment (e.g., the Federal Energy Regulatory Commission’s proposed Standard Market Design) and other uncertainties facing the industry make it imperative that a more sophisticated approach to asset valuation be undertaken. Traditional approaches are simply no longer appropriate.

R.J. Rudden Associates, Inc. is among the world’s premier strategic, economic and management consulting firms specializing in energy matters. Additional information is available on Rudden’s web site at www.rjrudden.com.

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